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September 13, 2021

Residential Consumer Intervener Association
c/o Midgard Consulting Inc.
Suite 828 – 1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Mr. Peter Helland, Director

Dear Mr. Helland:

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 Residential Consumer Intervener Association (RCIA) Information Request (IR) No. 1

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

Treatment of Confidential Material

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

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

disclose security-sensitive or commercially-sensitive confidential information, FEI has redacted those portions for the public record.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

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A. Project Need and Justification

1. Reference: Exhibit B-1-4 p. 1

> "FEI obtains most of its natural gas via Westcoast Energy's T-South system (T-South system), making a disruption on the T-South system the greatest supply risk facing FEI at present. The 2018 pipeline rupture on the T-South system (T-South Incident), and the challenges it presented for maintaining service to customers, underscored the importance of making new investments in system resiliency. Without additional investment in resiliency, future supply disruptions that may occur could have significant consequences in terms of cost to customers and socio-economic impacts to society generally."

1.1 Confirm whether the primary purpose of the TLSE project is to address a no-flow event resulting from a failure of the Enbridge B.C. (T-South) pipeline.

Response:

The primary purpose of the TLSE Project is to position FEI to be able to withstand, and recover from, a 3-day no-flow event on the T-South system, regardless of the cause of the supply interruption.

1.2 Does FEI consider the additional resiliency provided by TLSE to restore the level of resiliency that its Lower Mainland customers previously enjoyed, or is it considered to be an enhanced level of service, over and above the level of service that has historically been provided to FEI's Lower Mainland customers?

Response:

The TLSE Project will enhance the level of service and system resiliency over and above what has been historically provided to FEI's Lower Mainland customers.

1.2.1 For how many years were Lower Mainland customers served from a single pipeline tube on Westcoast's system?

Response:

Lower Mainland customers were served from a single (NPS 30 diameter) Westcoast pipeline starting in 1957 until the second T-South pipeline (NPS 36 diameter) was completed in 1972. However, as discussed in the response to BCUC IR1 1.1, T-South continues to operate as one system despite having two pipelines.

1.2.2 For how many years were Lower Mainland customers served from a single pipeline tube on FEI's system?

Response:

Lower Mainland customers were served from a single pipeline on FEI's system from 1957 to 1960.

2. Reference: Exhibit B-1-4 p. 23; Workshop Transcript (11 Mar 2021) pp. 103-105

Exhibit B-1-4 p. 23: "When the pressure in a portion of the gas system experiences a hydraulic collapse, FEI is unable to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment safely. These pressure variations can vary both in time (as the event progresses) and location (from area to area or even street to street). This uncertainty greatly complicates the ability of FEI to localize, manage and respond to the supply deficiency."

Workshop p. 103: "Yes, we have pressure monitors. We have some telemetry as well for stations. What I'm referring to is that we clearly do not have visibility of the length and volume of our distribution and how it's networked throughout the Lower Mainland…

Yeah, we have telemetry on some of the large customers for sure but not down into the -- as Doyle says, the distinction is between transmission or distribution… we have more customers, large customers, off of the transmission system, if you will, not a lot of customers in the distribution network, if that helps."

2.1 Explain how FEI's response is complicated without knowing which customers are receiving sufficient pressure.

Response:

FEI's response is complicated because of the lack of specific real-time feedback on the extent and location of low pressure and loss of supply within its distribution systems. As a result, FEI cannot respond precisely to the area impacted. This could result in:

- Isolating larger portions of a distribution system and impacting more customers than might otherwise be necessary; and/or
- The inability to dispatch service personnel effectively and proactively to investigate unsafe situations that may persist for customers that are impacted but have remained undetected.

One possible scenario in a system experiencing a hydraulic collapse, is that the pressure experienced by customers in the affected areas may drop low enough such that the customers' appliances fail to operate. The pressure may then recover somewhat (since some consumer appliances have shut down), resulting in repeated pressure increase/decrease cycles as appliances attempt to recover. In a hydraulic collapse, FEI anticipates that such situations would be occurring at multiple locations and would be widely distributed through the system. FEI's response to customers who have lost supply is to isolate those customers until the supply disruption is corrected and supply can be safely restored. As discussed in the response to BCUC IR1 5.3, currently FEI does not have distributed real-time or on-demand pressure monitoring of the distribution system such that it can determine where these unsafe situations are occurring, and hence specifically which customers and systems need to be isolated.

2.2 Explain why other sources of information (such as hydraulic models, SCADA monitoring of Intermediate Pressure and Transmission Pressure stations, large customers with remote pressure monitoring, and other remote telemetry units which monitor distribution system pressure and which FEI presumably uses to aid in calibration of its hydraulic models) are insufficient to inform FEI's response.

Response:

The other sources of information cited above would provide some support to FEI's decision-making when responding to a system experiencing a hydraulic collapse. FEI does have SCADA monitoring on its TP and IP systems and at some large customers, as indicated in the cited transcripts. This monitoring would allow FEI to identify some locations where hydraulic collapse may be imminent. However, they cannot provide information on whether downstream locations in distribution systems have actually experienced a hydraulic collapse. As described in the response to BCUC IR1 5.3, FEI has few telemetry units monitoring pressure within the distribution systems.

Hydraulic models rely on past measurements of customer demand and system pressures to initialize the models. During transient conditions, the system measurements would be too sparse and would not have the necessary granularity to set up the system model. As well, the computer software itself may not converge on a solution due to the transient conditions and low system pressures. As such, computer modeling is not expected to be helpful during potential pressure collapse scenarios.

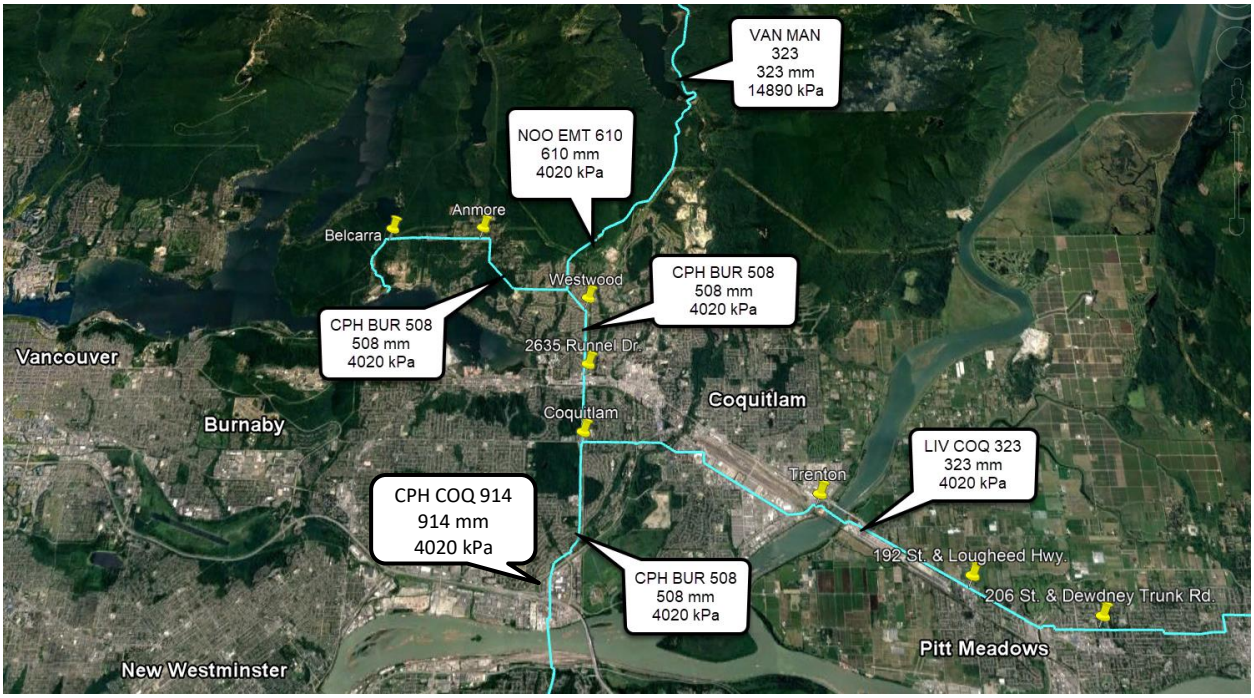
3. Reference: Exhibit B-1-4 p. 29

"FEI's own transmission system has a degree of resiliency due to the redundancy incorporated into its design. This redundancy has been incorporated as the need arose for additional system capacity to supply customers during peak load periods."

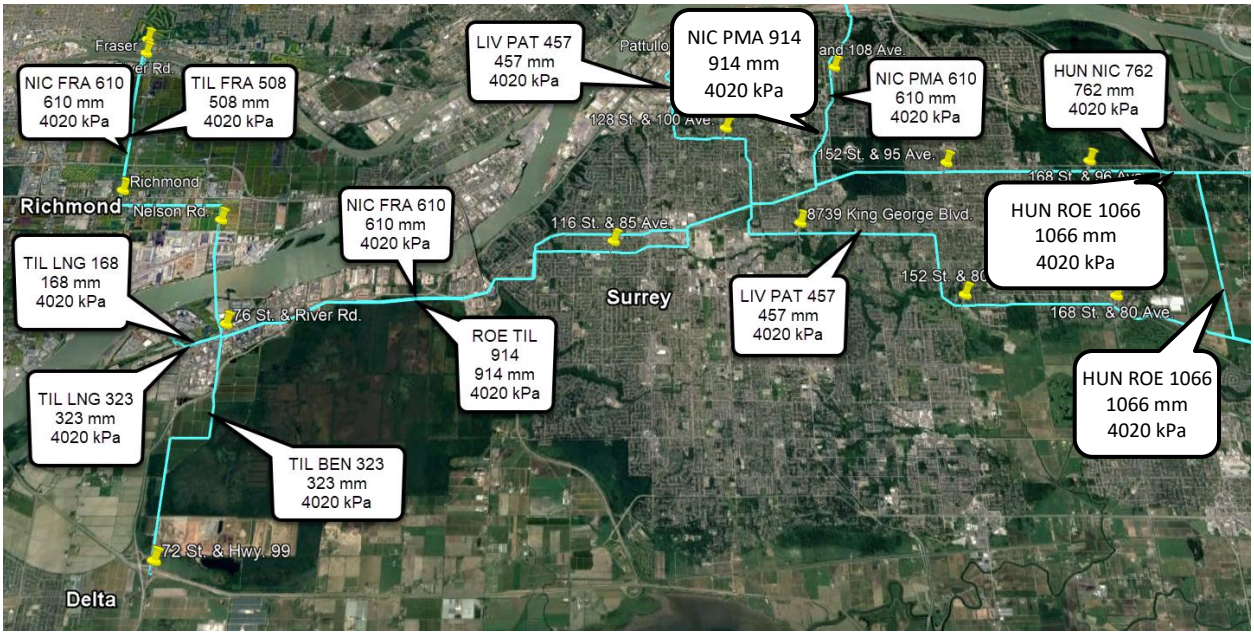
3.1 Provide a map showing the Coastal Transmission System pipelines and gate stations, including pipe diameters and maximum operating pressures.

Response:

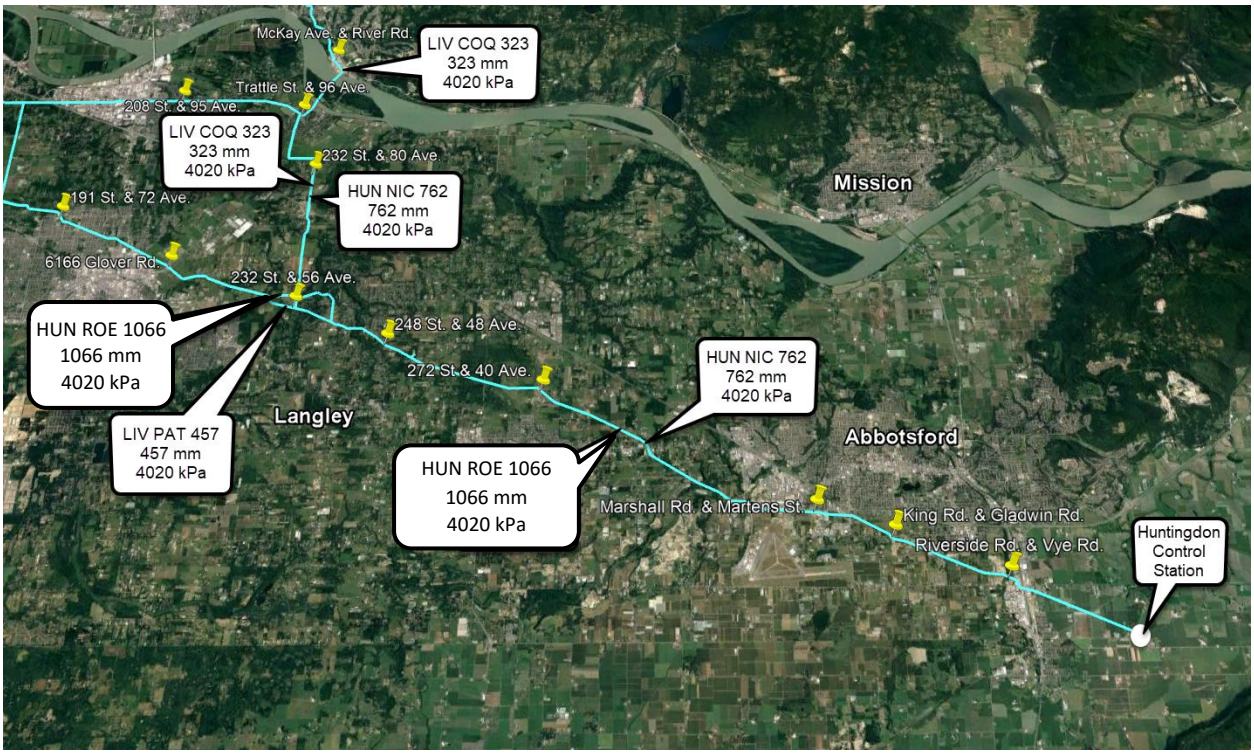
The following maps show portions of the CTS, including FEI's gate stations (yellow pin markers), pipe diameter, and maximum operating pressure[1] (MOP) for each transmission pipeline. Note that in some cases, pipelines run parallel to each other in the same right-of-way and may appear as a single line on the schematic. In these cases, both pipelines are labelled; for example, in the first schematic, the CPH COQ 914 and CPH BUR 508 pipelines run parallel from the Cape Horn Station until they diverge in Coquitlam.



[1] MOP refers to the actual current set pressure of the pipeline, and not the maximum pressure a given pipeline may operate at in accordance with the CSA Z662 standard.


NIC FRA 610
610 mm
4020 kPa
TIL FRA 508
508 mm
4020 kPa
LIV PAT 457
457 mm
4020 kPa
NIC PMA 914
914 mm
4020 kPa
NIC PMA 610
610 mm
4020 kPa
HUN NIC 762
762 mm
4020 kPa
Richmond
Nelson Rd.
NIC FRA 610
610 mm
4020 kPa
116 St. & 85 Ave.
8739 King George Blvd.
HUN ROE 1066
1066 mm
4020 kPa
TIL LNG 168
168 mm
4020 kPa
Surrey
LIV PAT 457
457 mm
4020 kPa
76 St. & River Rd.
ROE TIL
914
914 mm
4020 kPa
168 St. & 80 Ave.
HUN ROE 1066
1066 mm
4020 kPa
TIL LNG 323
323 mm
4020 kPa
TIL BEN 323
323 mm
4020 kPa
72 St. & Hwy. 99
Delta

1


McKay Ave. & River Rd.
LIV COQ 323
323 mm
4020 kPa
Trattle St. & 96 Ave.
208 St. & 95 Ave.
LIV COQ 323
323 mm
4020 kPa
232 St. & 80 Ave.
Mission
191 St. & 72 Ave.
HUN NIC 762
762 mm
4020 kPa
6166 Glover Rd.
232 St. & 56 Ave.
HUN ROE 1066
1066 mm
4020 kPa
248 St. & 48 Ave.
272 St. & 40 Ave.
HUN NIC 762
762 mm
4020 kPa
Langley
LIV PAT 457
457 mm
4020 kPa
Abbotsford
HUN ROE 1066
1066 mm
4020 kPa
Marshall Rd. & Martens St.
King Rd. & Gladwin Rd.
Riverside Rd. & Vye Rd.
Huntingdon
Control
Station

2

3

4. Reference: Workshop Transcript (11 Mar 2021) p. 125

"[Risk] has also been described as the possibility of an event occurring that will significantly disrupt the ability of the company to fulfill its mission. So it's really less about the probability of an event, and it's more about the magnitude of the impact of that event."

4.1 Provide Guidehouse's definition of "risk".

4.1.1 Describe how Guidehouse's definition incorporates the concepts of probability and consequence or impact.

Response:

The following response has been provided by Guidehouse:

Risk is the possibility of something bad happening. Merriam Webster defines risk as the possibility of loss or injury.[2] Guidehouse observes that it is important to understand the likelihood, i.e., the probability of a major system disruption whether it be a climate event, cyber event, or other man-made incident, 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.

4.2 Explain why Guidehouse considers impact to be of greater importance than probability when considering the risks facing a gas utility such as FEI.

Response:

The following response has been provided by Guidehouse:

The possibility of an event is an important consideration. Moreover, Guidehouse observes that the critical factors to consider include defining the risk, both in terms of the probability of the risk and the consequences. Guidehouse observes that probability of an occurrence often clouds decision-making relative to consequence mitigation.

[2] https://www.merriam-webster.com/dictionary/risk.

5. Reference: Exhibit B-1-4 pp. 35-36

"The subsections below set out the analytical framework through which FEI arrived at the Minimum Resiliency Planning Objective, and explain why it is an appropriate objective from the standpoint of customers, the Company and British Columbians generally. The considerations include:

• a risk assessment framework for resiliency investments should consider both the potential for a supply emergency to occur, and the magnitude of the associated consequences (Section 3.4.1); …

In analysing the need for investment in on-system storage, FEI has considered both the risk that a supply emergency will occur, and the potential consequences in the event that a supply emergency does occur. Other considerations, such as cost and ancillary benefits, inform the ultimate decision as well."

5.1 Confirm whether FEI has quantified the risk of a T-South failure or other supply-related no-flow event in terms of probability and consequence in order to compare the risk of such an event to other risks facing FEI. If confirmed, provide the risk assessment. If not confirmed, explain why not.

Response:

Given that a no-flow incident on the T-South system is the most impactful supply disruption to the Lower Mainland, FEI commissioned an analysis to explore the probability of a T-South failure, as discussed in the response to BCUC IR1 1.5.

With respect to the consequences of a T-South failure or other supply-related no-flow event, this information is quantified in Section 3.4.3 of the Confidential Application.

Since risk is mathematically quantified as the probability of an undesirable event occurring, multiplied by the consequences of that event if it occurs, together these analyses represent FEI's quantified risk assessment associated with the T-South system.

5.2 Confirm whether FEI has prioritized its spending toward projects that generate the greatest reduction in risk to FEI at the least cost. If confirmed, provide the analysis supporting the decision to proceed with TLSE.

Response:

FEI prioritizes spending towards projects which mitigate risks and/or provide benefits to its customers. With regard to the TLSE Application, FEI also confirms that, in providing a solution to

address the risk associated with a no-flow event on the T-South system, it has selected a project alternative that provides the greatest reduction in risk to FEI at the least cost.

The analysis which supports the decision to proceed with the TLSE Project is contained in Section 4 of the Application. Specifically, Section 4.2 describes the two-step alternatives analysis that was conducted to identify a cost-effective and technically-feasible solution that would meet FEI's Minimum Resiliency Planning Objective (in other words, address the identified risk of a 3-day no-flow event on the T-South system resulting in the loss of significant firm load). In Step One (described in Section 4.3 of the Application), FEI identified and screened all possible alternatives for meeting the Minimum Resiliency Planning Objective. Section 4.3.4.5.2 (refer to Confidential Table 4-3), explains how FEI determined that an optimal mix of on-system storage and pipeline capacity provides a lower cost approach to building resiliency than pipeline capacity alone. Finally, Section 4.3 concludes that the only feasible and cost-effective solution to meet the Minimum Resiliency Planning Objective is having on-system storage of between 2 and 3 Bcf within the Lower Mainland at the existing Tilbury LNG facility.

6. Reference: Exhibit B-1-4 Appendix A p. 48; Transportation Safety Board of Canada "PIPELINE TRANSPORTATION SAFETY INVESTIGATION REPORT P18H0088" pp. 4-5

Appendix A p. 48: "In the event of an unforeseen supply interruption, it will take several hours to discern the location and magnitude of the disruption. Additional time is required to plan and execute an appropriate curtailment response to prevent a system collapse."

TSB Report P18H0088 p. 4: "Approx. 17:29 An off-duty Westcoast employee contacted the Enbridge Calgary Gas Control (CGC) to report a large noise and fire near Shelley, BC, and the Fraser River. …

17:34 A local technician arrived at the 4AL2 segment valve site near Landooz Road (kilometre post [KP] 32.6) to investigate. …

17:56 Enbridge notified FortisBC of the pipeline rupture. …

Approx. 18:24 An RCMP (Royal Canadian Mounted Police) helicopter, with Westcoast employees on board, surveyed the site. It was confirmed that a natural gas pipeline rupture** and ignition had occurred on the NPS 36 L2 pipeline."

6.1 Explain why Guidehouse expects that it will take several hours to identify a problem on Enbridge's T-South pipeline, considering Enbridge was able to identify the location within 5 minutes of the October 2018 rupture and Enbridge informed FortisBC within 27 minutes of the rupture.

Response:

The following response has been provided by Guidehouse:

Guidehouse clarifies that it will take FEI several hours to understand the implications of a problem on the Enbridge T-South pipeline on its distribution system and execute an orderly shutdown of the system.

7. Reference: Exhibit B-1-4 pp. 43

"FEI is a voluntary member of the Northwest Mutual Assistance Agreement (NWMAA), which is comprised of 18 member organizations that utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest."

7.1 Does the NWMAA provide for the sharing of maintenance technicians who would be responsible for shutting in the system and performing relights once gas flows were restored?

Response:

No. The NWMAA pertains to the gas supply assets and resources that each member controls which may provide assistance in emergency conditions or events.

FEI is a member of the Canadian Gas Association, which has mutual aid agreements in-place so that members can make a formal resource request including technicians. Further, FEI is also a member of the Western Energy Institute, which also has mutual aid agreements that provide FEI access to natural gas and electric utility support (i.e., maintenance technicians) throughout Western Canada and the Western United States. Members of the Western Energy Institute can be found on their website: https://www.westernenergy.org/energy-companies/.

It is also important to note that within all of FEI's mutual aid agreements there are no contractual obligations between the parties to provide resources.

7.2 Which Canadian utilities does FEI have mutual aid agreements with that would allow FEI to request and utilize maintenance technicians for the relighting process?

Response:

Please refer to the response to RCIA IR1 7.1.

8. Reference: Exhibit B-1-4p. 23, 34; Workshop Transcript (11 Mar 2021) pp. 86-88, 95-96; BC Gas Safety Regulation 208/2019 Subsection 53(2)

Exhibit B-1-4 p. 34: "Without AMI technology, the shut-in process is crude. It requires technicians to visit valves and gate stations across the system to manually shut off the flow of gas to large geographic areas. This process not only stops supply to all customers in a given area, but also depressurizes the distribution system in that area. The benefits of having sufficient on-system supply to delay a shut-in are desirable; once a shut-in has been undertaken, this measure is irreversible in the short-term as it requires FEI's technicians to:

- Visit each premise to turn off the valve at the meter to isolate customer piping from the depressurized distribution system;
- Verify that 100 percent of individual customer valves are shut off;
- Purge the distribution system to remove air;
- Repressurize the distribution system once gas flows to FEI's system have resumed; and
- Revisit each premise to reopen the valve at the meter, purge air from customer piping, and relight each customer appliance."

8.1 Explain why FEI is required to visit each premise to turn off the valve at the meter.

Response:

Visiting each premises to turn off the meter set valve is a critical safety step that must be taken before pressurizing a system with gas. Provided below are common examples which illustrate why it is important for the meter set valve at each premises to be closed after a pressure collapse within a gas system.

When the pressure in the gas system collapses, customer appliances no longer operate. During the period of insufficient system pressure, a customer may try to unsuccessfully light their gas range and mistakenly leave their gas appliance flow control in the 'on' position. Alternatively, a customer may inadvertently bump the gas range's control knob(s), causing the appliance flow control to be left in the 'on' position. When the system is later pressurized, if the meter set valves are left open the premises lines would also become pressurized. Any appliances with the flow control in the 'on' position would allow gas that has not been combusted to flow into the customer's premises creating a hazardous situation.

The remaining appliances in a customer's premises, such as a furnace, hot water tank, or fireplace, typically have a 'safety valve' which is designed to automatically close when the appliance is not burning natural gas. However, these safety valves can fail, allowing uncombusted gas to flow into a customer's premises when the lines become pressurized.

In the situations outlined above, as gas begins flowing into a customer's premises unexpectedly, the customer inside the premises may smell natural gas and take appropriate action to resolve the situation before it becomes a serious safety issue. However, if a customer is not present or fails to take appropriate action to resolve the situation and the flow control on a customer's appliance allows uncombusted gas to enter a premises, an accumulation of gas could occur inside the structure, creating an explosive environment. This could result in a very serious safety incident involving significant harm to people and damage to the premises. As a result, FEI's policy is to always turn off the valve at every meter set connected to a system that has experienced a pressure collapse.

8.2 Explain what FEI would do to verify that 100 percent of individual customer valves are shut off.

Response:

To confirm 100 percent of individual customer valves are shut off, FEI would:

1. Develop a complete list of customer premises connected to the depressurized system;
2. Create disconnect orders for each affected customer in FEI's Work Order Management System (WOMS);
3. Assign these disconnect orders to field representatives responsible to disconnecting these customers;
4. Update the WOMS as disconnect orders are completed to track which disconnects are complete and which are outstanding; and
5. Ensure that repressurizing a system does not take place until all individual customer valves are confirmed to be closed using information from the WOMS.

Workshop p. 86: "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."

Workshop p. 95: "In the event that -- the example you're relying on is that we don't take any proactive measures and we just let the gas pressure system just naturally reduce pressure with the demand that you or I would have it on it. And at some point in time what's going to happen is the pressure will become so low and we do run the risk of air getting into our lines. These lines are no long pressurized. And air could come in from natural fittings that could seep a little bit. We also have third-party damages in our system and we have a number of third-party damages, folks, contractors, digging, excavators, pounding posts, that damage our lines. So we have a number of damages every day that we manage when our lines get compromised from third-party damages."

Exhibit B1-4 p. 23: "From a safety perspective, the uncontrolled drop in gas pressure can also introduce the possibility of air being drawn into the gas distribution grid. This is a potentially hazardous situation as the gas-air mixture can result in fire or explosion risks. Entrained air can also blow out the flames in customer appliances or equipment, resulting in misoperation and possible gas odour calls. Consequently, any air within the gas distribution pipes must be carefully purged by technicians attending each customer premise prior to relighting any appliances. This purge and regasification process could take days to months, depending on both the scale of outages and access to qualified resources."

8.3 Explain how and why FEI expects air to be drawn into the gas distribution system from an uncontrolled drop in pressure (presumably to zero).

Response:

As discussed at the TLSE Workshop, air can be drawn into a gas distribution system that has experienced an uncontrolled pressure collapse.

A pressure collapse occurs because customers continue to consume the remaining gas (line pack) that remains in the gas lines after the system valves are shut to isolate the system from upstream supply. As a result, the pressure within the isolated portion of the system will drop and customers at the end of the system will be the first to lose service. Over time, the pressure in the isolated portion of the system will reduce to atmospheric conditions and all the customers will lose gas service.

In FEI's experience, when a system pressure collapse occurs, air enters the collapsed system through various pathways. At atmospheric pressure, natural gas is less dense than air and will naturally flow out of any openings and the displaced volume will be replaced by air. These potential openings include:

- Appliances that are left on (such as gas ranges) or appliances that have defective safety valves (please also refer to the response to RCIA IR1 8.5);

- Above ground equipment leaks; and
- Third-party damage that goes undetected in depressurized lines (as there would be no noise of escaping pressurized gas or odour).

8.4 In the event that the system is at zero gauge pressure, explain why air is expected to enter the FEI system through fittings and leaks in the absence of a pressure gradient.

Response:

Air will enter the system through fittings and leaks when the pressure inside a gas line reaches atmospheric (zero gauge) pressure. This occurs because natural gas is approximately one-third less dense than air. At atmospheric pressure, natural gas will naturally flow out of any openings and the displaced volume will be replaced by air.

8.5 In the event that air is entrained in the distribution system in sufficient quantities to cause problems with appliance operation, explain why FEI expects the safety features on customer appliances to fail to safely shut down the appliance.

Response:

To clarify, air in the gas system will not negatively impact the safety features of an appliance. Rather, the concern is that if an appliance's safety features are not working as designed, air in the system could produce an unsafe situation inside a customer's home.

The following could occur when air in the gas system makes its way to a customer's appliance:

- A slug of air could come through a customer's appliance and extinguish the flame that had been produced by the burning natural gas. If an appliance's safety features are operating properly, its safety valve will immediately close when the flame is extinguished. However, if the safety valve does not close properly, then uncombusted gas will continue to flow into the residence. If the customer is not present at the time, or fails to take appropriate action, the amount of natural gas will accumulate to a level that may result in an explosion.
- A mixture of gas and air at a concentration that will not undergo combustion is fed into the appliance. The appliance will go through a series of relight attempts, while a concentration of gas and air mixture accumulates outside the combustion chamber. When the trapped air finally discharges out of the customer's appliance, the natural gas can relight, causing the accumulated air and gas mixture outside the combustion chamber to possibly also

ignite. This uncontrolled event could burn the person trying to manually relight the appliance, or the energy released outside the combustion chamber could damage the appliance, cause structural damage or a fire.

Workshop p. 87: "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. "

8.6 Following an event where the system pressure reached zero, is FEI proposing to leak survey and fix every leak on its system prior to reconnecting any customers?

Response:

FEI's priority when pressurizing a collapsed system is to ensure the pressurized system is safe to operate before reconnecting customers.

If the pressure collapse was of a very short duration and over a relatively small area, the risk of third-party damage to the system would be minimal. The longer the duration of the collapse and the greater the area of the pressure collapse, the greater the possibility that third-party damage will have occurred. Should the collapse result in a reasonable possibility of third-party damage, FEI would conduct a complete leak survey of the collapsed system.

8.6.1 How many leak repairs does FEI complete on its Lower Mainland system (distribution, intermediate, and transmission) in a normal year?

Response:

The table below provides the annual number of Lower Mainland system leaks FEI responded to and repaired for the last two full years:

	Lower Mainland Leaks		
Year	Distribution System (DP)	Transmission System (Formerly TP + IP)	Total
2019	6,132	35	6,147
2020	5,501	33	5,534

8.7 During the repressurizing and relighting operation following a no-flow event, confirm whether FEI would purge each and every service, or would FEI only purge the air from services where it had suspicions of air entrainment. If the former, explain why.

Response:

FEI's standard operating procedure following a system pressure collapse is to purge every service at the meter set prior to relighting the customer. The reason for purging every service is because air may have entered the system during the outage, and as discussed in the response to RCIA IR1 8.5, air in the system could present a safety issue.

8.8 If the system has been repressurized following a zero pressure event, and if FEI finds leaks from a leak survey, gas will be flowing out of the system. Explain how air would be entrained which would require purging with nitrogen.

Response:

Gas flowing out of the system for a long period would be expected to purge air upstream of the leak, but it is still possible for air that was entrained in the system downstream of any leaks to remain. As such, this gas/air mixture must be purged for the reasons described in the response to RCIA IR1 8.5.

8.9 If FEI has cause to believe air has been entrained, explain why FEI is required to purge the distribution system of air with nitrogen first instead of purging with natural gas?

Response:

The use of nitrogen to remove air from damaged/ leaking sections of pipe ensures there is an inert buffer between the trapped air and gas. This safety procedure ensures a potentially explosive mixture of gas and air cannot be present in FEI's system or flow through a customer's house piping.

FEI's standard practice is to use nitrogen to purge air out of the system when repairing NPS 6 pipe or larger. The only time nitrogen is not used to purge a section of damaged/leaking pipe is if the diameter of the pipe is less than NPS 6 or the repairs can be completed without the risk of introducing air into the pipe.

If an NPS 6 or larger diameter pipe is damaged and leaking, FEI's standard repair procedure is to isolate the leaking section and then draw the gas pressure down in the isolated section. When the pressure inside the damaged/leaking pipe is at atmospheric pressure, the damaged/leaking section of pipe is removed. When this section of pipe is removed, a significant amount of air can enter the remaining section of isolated pipe. When the repairs are complete and the isolated section of pipe reconnected, FEI's standard procedure is to purge this section of pipe with nitrogen prior to feeding natural gas into the pipe. A predetermined amount of nitrogen is introduced at one end of the isolated section, and immediately behind the 'slug' of nitrogen, gas is reintroduced into the repaired section of pipe. At the other end of the isolated section of pipe, a field employee measures the concentration of gas flowing out of a purge point. When the concentration of gas reaches 100 percent, the purge procedure stops and the pipe is ready for normal operation.

8.9.1 Is the requirement to purge with nitrogen specific to certain sizes or lengths of pipe (that is, larger diameter or longer lengths of pipe)?

Response:

Please refer to the response to RCIA IR1 8.9.

8.9.2 How would FEI accomplish purging its system with nitrogen? For a networked distribution grid, how would FEI be sure that it has fully purged each main? How would FEI purge larger distribution mains? For example, would FEI purge through small diameter customer services or would FEI excavate and tap into larger mains in order to purge them more quickly?

Response:

If a large system had to be purged, FEI would sectionalize the network by first closing the appropriate system valves. A sufficient number of purge points would be identified at the tail end of the isolated system and FEI would determine the safest and most efficient approach to complete each purge. If the collapsed system contained NPS 6 pipe or larger, excavations would be conducted and purge points installed on enough endpoints to ensure the purge is completed in a timely manner. If the collapsed system contained NPS 4 pipe or smaller, FEI's current practice is to purge through customer services, located at the tail end of the collapsed system.

For details on how and when FEI purges with nitrogen, please refer to the response to RCIA IR1 8.9.

8.9.3 In the event of a third party damage to a main or service, is it FEI's approved procedure to always purge the main or service with nitrogen?

Response:

Please refer to the response to RCIA IR1 8.9 for FEI's operating practices with respect to nitrogen purging.

8.10 Would FEI consider every main and service to be susceptible to third party damage and thus require a manual leak patrol? Or would FEI apply criteria or perform investigation (for example by accessing municipal excavation permits or call before you dig records) to narrow the number of mains and services that require a leak patrol?

Response:

Following a pressure collapse, FEI would apply a risk-based approach when determining how best to ensure the collapsed system was safe for restoration.

The considerations, and actions, that FEI would take when developing an initial leak survey plan would include:

- Consideration of the age of the affected system;
- Review the date of last leak survey and prior leak survey results;
- Determine how long the system had been depressurized;

- Review building use and density in the affected region;
- Confirm with the applicable municipality(s) to determine where below ground construction has occurred that may have impacted FEI's system;
- Review FEI's BC 1 Call database for excavation permits and cross reference these against the damage history of the callers; and
- Drive major roadways to look for evidence of unreported below ground construction activity.

Based on the findings of the actual leak survey, FEI would assess its approach to ensure the repressurized system is safe for operation.

8.11 Under what conditions would FEI expect to leak patrol all 20,000 kilometres of pipeline in the Lower Mainland?

Response:

One consideration that would drive FEI to leak patrol all 20,000 kilometres would be if the initial leak survey plan found a large number of below ground leaks and a large number of high-risk above ground leaks. These initial results would indicate if the newly pressurized system had been significantly compromised while depressurized. FEI would increase the percentage of mains and services leak surveyed, when the next section of pipe was ready to be repressurized and purged. Should the trend of finding a large number of below ground and high-risk above ground leaks continue, FEI would expand the risk-based leak survey approach until additional survey results did not find below ground or high-risk above ground leaks.

8.12 If FEI has repressurized its system, which would be required to complete the leak survey, explain why it would not begin immediately serving its customers.

Response:

Safely reconnecting customers would be FEI's priority should a system experience a pressure collapse. However, there are a number of steps that have to be successfully completed before FEI would be ready to safely reconnect these customers.

Before reconnecting customers, FEI must be confident the collapsed system is operating safely. The best approach to ensure safety would be to repressurize the collapsed system and then reconnect customers in a controlled manner.

Following a pressure collapse, the first step would be to sectionalize the system into areas that support approximately 2,000 customers. When FEI was ready to repressurize a section of the collapsed system, its pressure would be brought back up to normal operating conditions. Next, a leak survey would be conducted to ensure the newly pressurized section was safe for operation. If leaks were found, repairs would be prioritized based on the number of available resources and the risk profile of each leak. Only after FEI determined the newly pressurized section was safe would FEI start to repressurize the next sectionalized part of the collapsed system. This process would continue until all the collapsed system was successfully repressurized. While FEI crews continued to safely repressurize remaining sections of the collapsed system, FEI would have other dedicated groups of employees working in parallel, relighting customers connected to sections of the system that are safe to resume operation.

8.12.1 How would FEI prevent its customers from turning on their own gas service once the system was repressurized?

Response:

The current equipment on a customer meter set would make it impossible to prevent a determined customer from pre-emptively turning on their gas service and attempting to relight their appliance(s). However, at the onset of the outage, and for the duration of the restoration, FEI would be continually broadcasting public appeals in the media reminding customers not to attempt to restore service on their own as this could present safety risks.

Please refer to the response to BCUC IR1 16.2 on how AMI would benefit customers by providing an additional option to relight their appliance(s).

8.13 Has FEI considered not shutting off the valves at each customer (or each residential customer) meter and allowing customers to continue to draw gas until the system reaches zero pressure? Identify and explain FEI's concerns with such an approach.

Response:

During a widescale no-flow event, FEI would not have the resources to quickly close every meter set valve. Consequently, customers would continue to use gas until their ongoing demand on the system resulted in a system pressure collapse.

A system pressure collapse is the worst outcome of a no-flow event because all customers on the system will lose an important source of energy and it will take FEI weeks to months to repressurize the collapsed system and relight the affected customers.

For an explanation of why FEI considers it a necessary safety practice to ensure meter set valves are closed before repressurizing and purging the collapsed system, please refer to the response to RCIA IR1 8.1.

Gas Safety Regulation subsection 53(2): "If a gas supply has been turned off, a person must not turn the supply on again until the person (a) notifies all affected consumers, and (b) carefully checks all outlets and pilots to ascertain that they are relighted or turned off."

8.14 Faced with the prospect of having to complete 700,000 relights in winter following a no-flow incident, would FEI apply to the jurisdictional authority for an exemption to subsection 53(2) in order to allow customers to turn on their own gas service or otherwise complete their own relights?

8.14.1 What additional steps would FEI take to ensure this is done safely?

Response:

FEI does not believe an exemption from Technical Safety BC is required.

Section 53(2) of the Gas Safety Regulation (GSR) does not prohibit a customer from attempting to relight the pilots on their own appliances.

Section 53(2) of the GSR provides that FEI must not turn the gas supply on until FEI has notified affected customers and carefully checked outlets and pilot lights to ascertain that they are relighted or turned off. FEI's standard practice is to attend customers' premises to turn on the gas supply at the meter and enter the premises to relight the pilots on appliances where required. In cases where a customer does not want an FEI customer service technician to enter the premises, FEI recommends to the customers that a qualified person turn the gas supply on and perform the required relights. The qualified person will confirm that the pilots have either been relit or are turned off (so gas is not flowing to the appliance).

Please refer to the response to BCUC IR1 16.2 for details on how AMI would improve the efficiency of the relight process.

8.15 How would the installation of Advanced Metering Infrastructure alter the relight process?

Response:

Please refer to the response to BCUC IR1 16.2 for details on how AMI would improve the relight process.

A potential remote reconnect option enabled by AMI would satisfy the requirements of Gas Safety Regulation subsection 53(2b) to carefully check that outlets and pilots are turned off or relighted. The remotely supported relight process that is under consideration is summarized as follows:

- The advanced meter installed at the customer's premises would perform a remote dial check. This remote dial check process could consist of:
  - FEI gains verbal confirmation from the customer that all appliance feed valves have been positioned in the off position;
  - FEI then remotely opens the internal valve within the advanced meter;
  - The advanced meter would monitor for any flow for the next three minutes;
  - If flow is detected by the advanced meter, the meter would automatically close its internal valve and send a signal back to the FEI employee, indicating the situation is not safe to perform the relight(s); and
  - If during these three minutes no flow is detected by the advanced meter, the remote dial check has confirmed it is safe to relight the appliance(s) and the FEI employee will inform the customer they can proceed and relight their appliance(s).
- FEI could offer the customer the option of having a qualified person remotely support (via a video link) the customer during the relight or if necessary an FEI Customer Service Technician could provide onsite support.

9. Reference: Workshop Transcript (11 Mar 2021) p. 88

"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."

9.1 Provide additional details of the referenced event, including utility name, location, date, and the steps taken to shut down, purge, and relight its customers.

Response:

The referenced event was associated with the wildfire which swept through the Fort McMurray region of Alberta in May 2016. The impacted utility was ATCO Gas. A general description of ATCO's response was published in the Winter 2016 edition of the Association of Professional Engineers and Geoscientists of Alberta publication, *The PEG*.[3]

FEI notes that ATCO's account of their response is consistent with that described in FEI's Application and the TLSE Workshop, including:

- the need to confirm the safety and availability of supply from the upstream gas provider prior to beginning customer restoration;
- the need to conduct inspections and any necessary system repairs prior to beginning customer restoration;
- the need to visit every home and business location to shut off the service valve;
- the need for—and complexity associated with—purging and regasifying the distribution system;
- the number of field crews involved (approximately 150 people); and
- the number of customers impacted and the timelines of ATCO's response (approximately 10 days to execute the plan once the preliminary steps above were completed).

FEI also notes that in addition to a different initiating cause (i.e., a wildfire which also damaged property and infrastructure), this incident took place in the summer when the demand for gas for space heating purposes would be very low, and winter weather (e.g., snow and ice) did not hinder the response. As such, this supply disruption does not necessarily represent the same response time or life-safety implications that would result if a similar event occurred during extremely cold winter conditions. As such, the Colorado incident (described on page 88 of the Workshop Transcript), which happened in late December during cold winter conditions, is more representative of a service disruption event which could occur in the Lower Mainland service region.

[3] https://online.flippingbook.com/view/874501/53/.

10. Reference: Workshop Transcript (11 Mar 2021) p. 89

"And not so obvious, but an outage of this duration would also have a significant impact on the local electrical system, and would likely overload that system, causing electrical outage as well."

10.1 Has FEI discussed the implications of a wide-area gas outage on the electrical system with BC Hydro?

10.1.1 Has BC Hydro explained to FEI how it would manage its system to accommodate the expected increase in electrical demand? If so, please summarize this information and highlight any concerns expressed by BC Hydro.

10.1.2 Is FEI aware of whether BC Hydro has public messaging prepared that would be utilized in the event of a wide-area gas outage?

Response:

FEI confirms that discussions of the impacts of a widespread gas outage on the BC Hydro electrical system have taken place, both with senior executives, as well as technical representatives from both companies.

Shortly following the T-South Incident, a joint working group of BC Hydro and FEI engineers was formed to explore options to manage the implications of a wide-area gas outage on BC Hydro distribution feeders and substation transformers. The joint working group concluded that:

- More coordination would be required between the two utilities if this type of event occurred;
- Further scenario analysis of BC Hydro's system would be required to identify how to manage the impact of each unique gas outage; and
- Rotating electric feeder outages may be required depending on the specific gas outage.

FEI cannot confirm whether BC Hydro has public messaging prepared that would be utilized in the event of a wide-area gas outage. BC Hydro did work with FEI on possible messaging during the Westcoast T-South Incident.

11. Reference: Workshop Transcript (11 Mar 2021) p. 90; Exhibit B-1-4 Appendix B pp. 5-6

Workshop p. 90: "And the T-South event had significant consequences for a number of customers. But it could have been orders of magnitudes worse. And as such, we engaged Price Water Coopers to conduct a study that confirmed that the socio-economic impacts would be significant."

In Appendix B, PricewaterhouseCoopers identifies three scenarios that a potential natural gas disruption could have on British Columbia.

11.1 Confirm whether PricewaterhouseCoopers developed the durations of the scenarios or whether FEI developed the scenario durations.

Response:

The following response has been provided by PwC:

Scenario bounds were defined based on the notable conditions that would create a material step change in impact for one or more stakeholder groups in BC. These were identified by PwC research, supported by information collected from external (impacted sectors / stakeholder groups) and internal (FEI) interviews.

For example:

- Our stakeholder interviews indicated that major hospitals are mandated to have a three (3) day back up heating source, yet some critical systems / capabilities for full operations (e.g., sterilization) may be limited.
- Information gathered from internal interviews included FEI's operational experience in outages and bringing systems back online, which played a part in informing the "Duration" bounds, predominantly related to restoring natural gas service.

11.2 Provide timelines with milestones and activity durations for each scenario from the point of gas supply interruption until the restoration of service.

Response:

The following security sensitive response has been provided by PwC:

[redacted]

[redacted]

[redacted]

12. Reference: Exhibit B-1-4 pp. 35, 67

Exhibit B-1-4 p. 35: "FEI has identified the following Minimum Resiliency Planning Objective:

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."

Exhibit B-1-4 p. 67:

Table 3-3: Summary of Mt. Hayes LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification[60]	VI Peak Design Load
Mt. Hayes	8 MMcf/day 200 days to fill	1.5 Bcf 10 days reserve	150 MMcf/day 100% of VI daily design load	150 MMcf/day

12.1 Can FEI's system in the Interior (Thompson, Okanagan, Kootenay) withstand and recover from a 3-day "no-flow" event on a) T-South or b) TC Energy's Foothills pipeline, including on peak days? Explain any limitations on the resiliency of the Interior system.

Response:

FEI's Interior Transmission System (ITS) is currently not able to support all firm load during a supply interruption from either the Westcoast T-South or TC Energy interconnection points at all times of the year. The ITS was originally constructed as a single NPS 12 pipeline from the Westcoast T-South system at Savona, reducing to an NPS 10 in the South Okanagan, and then NPS 8 in the West Kootenays, finally terminating in Nelson.

Over time, the system capacity was upgraded to accommodate load growth by the addition of the NPS 12 East Kootenay Link pipeline from Yahk to Trail (connecting to the TC Energy Foothills system), and more recently, the NPS 24 Southern Crossing Pipeline (SCP) from Yahk to Oliver. Despite its evolution, the ITS has inherent resiliency limitations because under colder spring, fall or winter conditions the ITS must rely on some supply from both the T-South system and the TC Energy system to support all customers supplied by the system.

The ITS is more resilient to supply interruptions from TC Energy at Yahk. Contingent on FEI securing sufficient supply from Westcoast, FEI can replace supply from TC Energy into the South Okanagan and Kootenays by moving gas from Westcoast at Kingsvale through reverse flow on FEI's Kingsvale to Oliver NPS 12 pipeline. FEI could then meet the needs of firm customers on the ITS, with interruptible customers curtailed, for all but the coldest days each winter expected in late December through early February.

If the Westcoast T-South supply was lost at Savona and Kingsvale, the ITS is less resilient and could begin to experience supply shortages in the Thompson region around Kamloops in the September through May period (without additional curtailment of firm customer demand). FEI's proposed Okanagan Capacity Upgrade Project would improve resiliency in this scenario by reducing the window where supply shortages could occur in the October through April period.

Although there remain some resiliency challenges in the Okanagan, the potential impacts to the LML as a result of a no-flow event on the T-South system are far more significant and the exposure exists over larger parts of the year.

12.2 Is FEI aware of any other Canadian gas utilities that have a similar resiliency planning objective? If so, provide the names of the utilities along with their resiliency planning objectives.

Response:

Please refer to the response to BCUC IR1 10.4.1.

13. Reference: Exhibit B-1-4 pp. 31

"FEI responded to the significant gas supply deficiency by curtailing load in two ways: directing large volume and/or interruptible customers to immediately disconnect from the system, and by making public appeals for all customers to reduce their gas usage."

13.1 Provide the number of firm customers that FEI requested curtail their consumption during the October 2018 no-flow event and the number that curtailed their consumption.

Response:

During the October 2018 no-flow event, of the approximately 230 large customers (both firm and interruptible) that FEI contacted individually to curtail their consumption, approximately 50 customers were either firm or held an amount of firm capacity. In addition, FEI made public requests to all of its remaining approximately 1 million customers to reduce their consumption.

14. Reference: Exhibit B-1-4 pp. 145-146; Exhibit A-12 BCUC IR1 7.3

Exhibit B-1-4 p. 145: "Table 5-9: TLSE Project Schedule and Milestones … LNG Storage Tank Expansion Completion, Sep 2026"

RCIA notes that until September 2026, FEI is at risk of a no-flow event.

Exhibit A-12 IR1 7.3: "7.3 Please confirm, or explain otherwise, that under the FEI's General Terms and Conditions, FEI has the right to restrict service to any of its customers under certain circumstances.

7.3.1 Please discuss whether no-flow events on the T-South system could constitute an emergency.

7.3.2 Please discuss whether FEI considers that the General Terms and Conditions provide FEI the right to restrict service to any of its customers during an event such as the 2018 T-South Incident."

14.1 Has FEI prepared plans for curtailment of customers in anticipation of future no-flow incidents? Such plans could include thresholds of supply availability that would trigger curtailment, prioritization of customers to curtail, steps to be taken to curtail including contacting the customers and deployment of staff, etc. If so, please describe what FEI has done to plan such an eventuality.

Response:

Yes. FEI regularly prepares and practices for potential future incidents by performing and testing a variety of emergency exercises based upon various emergency plans. As part of its response to a potential severe supply shortage as a result of the T-South Incident, FEI prepared a System Preservation and Service Restoration (P&R) Plan (which was filed confidentially with, and reviewed by, the BCUC). The P&R Plan includes principles and strategies aimed at maintaining service to as many customers and areas as possible under evolving conditions. The P&R Plan includes curtailment strategies and analysis of customer demand by groups of customers and regions of customers and how FEI could respond under various scenarios. The P&R Plan will evolve as circumstances change, such as with greater resiliency on the system or if additional technical solutions (such as AMI) become available.

15. Reference: Exhibit B-1-4 p. 41; Exhibit B-1-4 Appendix A p. 12

Appendix A p. 12: "Because the amount of linepack available for intra-day flexibility is directly correlated to the amount of demand and the amount of gas in the pipeline segment, linepack has limited capability to serve resiliency in the event of a prolonged supply disruption."

Exhibit B-1-4 p. 41: "On October 10, 2018, Westcoast declared *force majeure*, effective as of October 9, 2018. Westcoast's *force majeure* notice indicated that service was interrupted as a result of the rupture of the NPS 36 pipeline, and that flow was restricted to zero on all delivery points on the T-South system between Compressor Station 4B and Huntingdon, as shown in Figure 3-5 above."

15.1 During the 2018 no-flow event caused by the rupture of T-South, at what date and time did FEI cease to draw linepack from T-South?

Response:

In general, during no-flow events FEI will try to minimize any impacts to Westcoast's T-South line pack. It is critical for FEI and other interconnects that Westcoast T-South's line pack is maintained at a healthy level in order to avoid a system pressure collapse; failure to do so can result in complete loss of T-South delivery to all interconnects.

For example, during the 2018 T-South Incident, even though there was no gas flowing on T-South past Station 4B, FEI was still relying on T-South between Station 4B and Huntingdon to flow Alberta gas supply into the Interior and Lower Mainland; therefore, the line pack in T-South needed to be maintained.

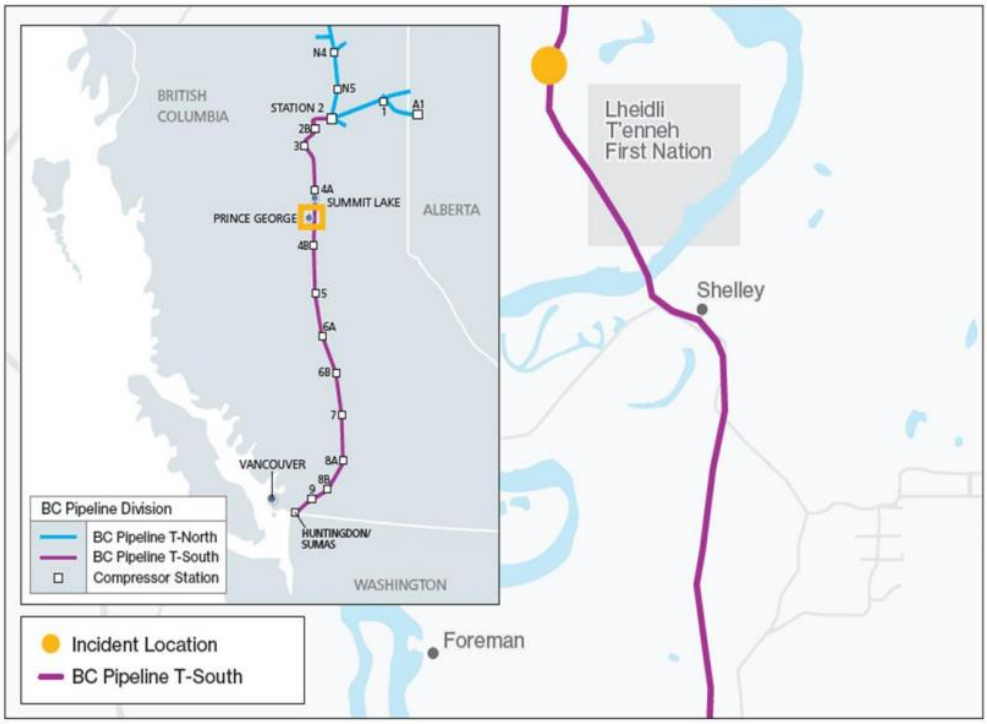
15.2 In the course of the October 2018 T-South Incident, did FEI isolate its system from the T-South system?

Response:

FEI did not isolate its system from the T-South system during the October 2018 T-South Incident.

The point of rupture was in the north near Station 4A of the T-South system in the vicinity of Prince George, which stopped all gas supply past Station 4B (refer to Figure 3-5 from the Application, reproduced below for convenience). However, the T-South system south of Station 4B was not physically impacted, and it allowed FEI to continue to import limited gas supply from Alberta via the Southern Crossing Pipeline, which was fed into the T-South system at Station 7 and subsequently delivered to the Huntingdon Station and into the Lower Mainland.

Figure 3-5: Location of Rupture on the T-South Pipeline



16. Reference: Exhibit A-12 BCUC IR1 9.4.1

"If possible, please explain how FEI is resilient to risks other than no-flow scenarios caused by a single-point-of-failure, such as earthquakes, malicious acts and dig-ins. In your response, please explain the probability of these other risks in comparison and the mitigation measures FEI takes to manage these other risks."

16.1 Describe the Huntingdon station and its redundancy in supplying the CTS. Can it fully supply the winter peak demand if any of its station equipment fails?

Response:

FEI's Huntingdon Station has two separate and redundant sets of piping, valves, and regulators, referred to as Huntingdon "Station 1" and "Station 2". With the exception of the inlet and outlet headers, each "station" is individually capable of flowing the entire CTS winter peak demand.

To cover off any potential overlap, and provide full redundancy, in 2015 FEI constructed a station bypass pipeline and associated facilities that are also capable of meeting the CTS winter peak demand. This bypass pipeline is intended to operate if the Huntingdon Station site itself is out of service for any reason.

Both of these "stations" as well as the bypass pipeline are connected to the two pipelines leaving Huntingdon Station. Considering the two stations and the bypass, FEI has designed the facilities so that there is no common header that could result in a single point of failure within the Huntingdon Station or the connections to the existing pipelines.

16.2 Characterize the redundancy of the CTS leaving the Huntingdon station. Can the CTS supply the winter peak demand in the event of a failure of a single pipeline?

Response:

There are two main parallel pipelines, an NPS 42 and an NPS 30, leaving the Huntingdon Station that supply the CTS. Neither pipeline on its own, if completely isolated from the other, could support the peak winter demand. However, due to placements of mainline isolation valves and crossover assemblies between the two pipelines at regular intervals, the failure of any individual pipeline segment would not result in the complete and extended loss of the entire pipeline. Individual pipeline segments would be isolated by closing mainline valves upstream and downstream of a failure point, and crossover assemblies opened to reroute gas flow through the remaining pipeline along the same segment. Therefore, with the isolation of only segments of the NPS 42 and NPS 30, there is redundancy of the CTS leaving the Huntingdon station to meet all but the highest winter load demand requirements.

B. Description and Evaluation of Alternatives

17. Reference: Exhibit B-1-4 p. 113-114; www.enbridge.com/projects-and infrastructure/projects/tsouth-reliability-and-expansion-program

Exhibit B-1-4 p. 113: "Traditionally, Westcoast has assisted FEI in managing these instances by refraining, where it can, from enforcing the 5 percent limitation in the OBA. However, Westcoast's ability to provide this additional flexibility to FEI has become more limited in recent years as the Westcoast system has become fully contracted and capacity has become harder to obtain."

Exhibit B-1-4 p. 114: "Second, FEI's ability to rely on Westcoast's waiver of the 5 percent requirement into the future is less certain than it has been in the past. FEI expects that Westcoast will be operating in an increasingly constrained pipeline environment in the winter given the existing market conditions, such that the provision of the 5 percent term within the OBA may become more strictly enforced."

Enbridge website: "This work, known as the T-South Reliability and Expansion Program, will involve: replacing old compressor station units with new, more reliable and efficient units; adding an additional compressor station unit; and undertaking smaller upgrades and operational maintenance at various facilities along the system. These upgrades are being done as part of operating a safe natural gas pipeline system, and to accommodate an incremental 190 MMcf/d of firm capacity."

17.1 Explain whether the compression and capacity upgrades Enbridge/Westcoast is making to its T-South system will allow Westcoast to continue to refrain from enforcing the 5 percent limitation in the OBA, or to amend the OBA to remove the 5 percent limitation.

Response:

FEI considers it unlikely that the 5 percent limitation will be amended or removed from the OBA contract. This is because the 5 percent limitation is taken into account in setting Westcoast's design criteria on the T-South system. To change or modify this design criterion, Westcoast would need to make further capital upgrades to its T-South system.

In terms of enforcement, Westcoast can enforce this rule from time to time, and will likely continue to do so in the future given that operating conditions on their system will evolve and change over time.

17.2 Explain why FEI believes Westcoast will more strictly enforce the OBA and 5 percent limitation, considering the compression and capacity upgrades on T-South.

Response:

Please refer to the response to RCIA IR1 17.1.

18. Reference: Exhibit B-1-4 pp. 63, 100-101; Workshop Transcript (11 Mar 2021) pp. 167, 225-226

Exhibit B-1-4 p. 100: "While FEI expects the tank to last beyond 55 years, it makes economic and practical sense to replace the tank now to capture available economies of scale in the construction of a single, larger tank."

Exhibit B-1-4 p.101: "Additionally, replacing the 0.6 Bcf tank at some point in the future presents other disadvantages. For example, in order to maintain resiliency and uninterrupted service to FEI's customers, FEI would need to complete the construction of the replacement 0.6 Bcf tank (i.e., a fourth LNG tank onsite90) before it could demolish the existing Base Plant tank. As an operating, brownfield site, this would create significant additional constraints on space for construction activities and siting new facilities."

Workshop p. 167: "Okay, so 2 Bcf you consider the minimum, 3 Bcf is better, because it provides these incremental benefits. Would more than 3 Bcf provide additional benefits?

Yes. From an operations perspective, anything that will help resiliency more is better."

Workshop p. 225: "So to clarify, as I mentioned earlier, the planned expansions end at the Tilbury 1B expansion in terms of our known plans, and should the TLSC proceed and the base plant be demolished, you know, that is the available space we have on site."

18.1 If additional LNG storage provides additional resiliency and thus has value to FEI and its customers, and as there is no plan to utilize the space that the Base Plant currently occupies, explain why FEI would forego the additional resiliency benefit of the Base Plant tank and incur additional cost at this time to demolish it even if FEI proceeds with a 3 BCF tank.

Response:

Maintaining the Base Plant would not benefit customers if FEI constructs the new 3 Bcf TLSE Project. It would not be cost-effective and there are other benefits from removing it.

As explained in the response to BCUC IR1 40.1, the average service life of the Base Plant tank is 40 years and thus the asset has already exceeded its financial life by 10 years (the tank was placed into service in 1971). The operational life of the tank has been extended due to the maintenance activities over the years that have involved replacing and repairing major components of the tank. While FEI could continue to perform sustaining capital maintenance on the Base Plant tank, this maintenance would be an added cost to customers and the additional operational life that might be achieved through such sustaining capital activities is uncertain given that the tank is already 50 years old. The TLSE tank will also benefit from modern design standards and best practices that offer improved safety and environmental performance over the Base Plant tank.

Additionally, as explained in the response to BCUC IR1 16.22, there are also benefits to removing the Base Plant facilities as part of the TLSE Project, as the demolition activities can be planned and synchronized as part of the overall Project execution, thus allowing for a more efficient and streamlined process. Finally, continuing to operate the Base Plant facilities would increase the operation and maintenance costs for the overall Tilbury facility, as FEI would be operating and maintaining three storage tanks (the Base Plant tank, Tilbury 1A tank, and the new TLSE tank); in particular, the maintenance requirements for the Base Plant tank would be different from the other newer tanks due to the Base Plant tank's age and design.

18.2 Explain whether FEI could retain the Base Plant tank until such time as it has reached the end of its life or until a significant capital expenditure is required to maintain it in safe operating condition, at which time it could be demolished.

Response:

Please refer to the response to RCIA IR1 18.1.

Exhibit B-1-4 p. 63: "Although the design capacity of the Base Plant tank is 0.6 Bcf as shown in Figure 3-13 above, FEI is currently operating the tank at a reduced capacity while it assesses the future operability of the tank.57"

Exhibit B-1-4 Footnote 57: "At 50 years old, the Base Plant tank is nearing the end of its useful life."

18.3 Provide the results of FEI's assessments of the Base Plant tank.

Response:

In order to properly assess the expected remaining operational life of the Base Plant tank FEI would need to conduct an internal inspection of the tank. This would require the tank to be drained to allow safe entry and assessment. FEI has not completed this internal inspection given the difficulty and cost associated with this work.

FEI recently completed a seismic analysis of the Base Plant tank that led to derating the operating capacity of the Base Plant tank to align with current day seismic design standards. This limits the ability for FEI to utilize the Base Plant tank for its full operating capacity. The Base Plant tank remains in safe operation today, and is compliant with all regulatory requirements. Further work is required to determine the extent of the capital improvements necessary to return the tank back

to full operating capacity. However, even if these capital improvements were to proceed, the Base Plant tank would still not provide the enhanced safety and environmental performance enabled by the modern design standards of a new tank.

The statement that the Base Plant tank is nearing the end of its useful life is based on the expectation that the investments to upgrade old equipment and make ongoing improvements to address changing seismic requirements would be significant in the upcoming years and therefore it is preferable to decommission and demolish the Base Plant tank and construct the TLSE Project.

19. Reference: Exhibit B1-4 p. 100; Workshop Transcript (11 Mar 2021) pp. 164, 201-202

Workshop p. 201: "And, finally, the project includes decommissioning and the demolition of the above ground portions of the Tilbury base LNG storage tank and liquefaction facilities…

The base plant liquefaction has not been utilized over the past couple years as we have found it more efficient and cost effective to utilize the newly installed liquefaction capacity rather than the older base plan equipment."

19.1 FEI states that the Base Plant liquefaction facilities are no longer utilized but appear to remain functional. Explain why FEI proposes to demolish the Base Plant liquefaction facilities, instead of keeping them as spares in case there are: 1) problems with the T1A liquefaction train, 2) the TLSE tank is depleted following a no-flow event and the reserve or even full T1A liquefaction capacity is incapable of refilling the tank within an acceptable timeframe.

Response:

The Base Plant liquefaction capacity is 5 MMcf/day, as compared to the Tilbury 1A liquefaction capacity of 33 MMcf/day and there is limited to no interchangeability of equipment between the two facilities. FEI operated the Base Plant liquefaction facilities safely for nearly 50 years; however, given the age of the equipment, ongoing investments were required to continue to meet current day safety standards. Furthermore, the Base Plant liquefaction equipment is ageing, with some equipment such as the mixed refrigerant compressor becoming increasingly maintenance intensive and unreliable and, therefore, costly to retain.

FEI expects that the new Tilbury 1A liquefaction train will operate reliably and hence the cost to maintain the nearly 50 year old Base Plant liquefaction equipment as standby equipment is not warranted. In an instance where the TLSE tank is depleted following a no-flow event, it is expected that it will be more cost effective to rely on the liquefaction reserve capacity from Tilbury 1A as well as any excess site capacity available at that time to refill the TLSE tank, as discussed in Section 5.3.1.4 of the Application.

19.2 Explain whether the Base Plant liquefaction could be maintained as an emergency backup.

Response:

Please refer to the response to RCIA IR1 19.1.

Exhibit B-1-4 p. 100: "FEI could, in theory, achieve the desired storage capacity with a combination of the existing 0.6 Bcf Tilbury Base Plant tank and a new storage tank. This combination might, on first blush, look like it would reduce the overall cost of the Project. In reality, the analysis is more complex; both the technical considerations and the economics are unfavourable."

Workshop p. 164: "Using the existing base plant storage, including its regasification, and adding additional storage and regasification capability at our Tilbury site is a consideration. This option, however, would not lead to the economies of scale on a single larger tank and would be most costly over time for our customer, recognizing that the existing base plant facilities are over 50 years old and would still require replacement at some point in the future."

19.3 Explain why the Base Plant regasification train is being demolished, as the analysis on page 100 and the transcript quote provide FEI's reasons why the Base Plant tank should be demolished (i.e., there are economies of scale in the construction of a single, larger tank) but do not address the reasons why the regasification train should be demolished.

Response:

The Base Plant regasification equipment is 50 years old and the equipment is approaching the end of life. While still operational, obsolescence is an issue with repair and replacement parts increasingly difficult to source. Some equipment requires continual monitoring as it has been subject to corrosion. Auxiliary equipment such as the electrical system is also in poor condition and consists of a single supply circuit and a single transformer, which poses additional risks to power supply reliability.

Once the new regasification equipment has been installed and commissioned, the Base Plant regasification trains would be surplus to FEI's regasification requirements; incurring the cost to modernize the equipment and provide ongoing maintenance to ensure their reliability would not be warranted. For this reason, FEI intends to decommission and demolish the regasification train once the new equipment has been installed.

19.4 Explain whether the proposed 200 mmcf/d regasification units are modular in that three units could be installed now, with additional units added later as the load and winter peak demand grow.

Response:

The proposed 200 MMcf/day regasification units are modular and, from a technical standpoint, could be installed in phases. FEI has determined that it is appropriate to install the units at the outset because FEI identified 800 MMcf/day regasification as necessary for resiliency and FEI has not identified an economic benefit associated with phasing.

19.5 Explain whether the existing Base Plant regasification capacity of 150 mmcf/d could be maintained and provide continued service for the foreseeable future if FEI proceeds with a 2 or 3 BCF tank and 600 mmcf/d of new regasification.

Response:

Please refer to the response to RCIA IR1 19.3 with respect to the limited remaining service life of the existing Base Plant regasification system.

C. Project Description

20. Reference: Exhibit B1-4 pp. 127, 132; Exhibit A-12 BCUC IR1 30.1; Workshop Transcript (11 Mar 2021) pp. 215-216

Exhibit B-1-4 p. 127: "Construction of additional liquefaction is not within the scope of the TLSE Project."

Exhibit A-12 IR1 30.1: "Please describe how the reserved 5 MMSCFD liquefaction capacity from the Tilbury 1A LNG liquefaction system is adequate for the purposes of the proposed 3 Bcf tank."

Exhibit B-1-4 p. 132: "Electrical power, including 13.8 kV and 4.16 kV feeder lines to supply the LNG storage tank systems, BOG compressors, and regasification package…

An emergency generator to provide electric supply for critical loads to ensure operations even during a site-wide power failure. At a minimum, these critical loads will include one in-tank LNG pump, three HP send-out pumps, three vapourizers, and instrument air compressors, as required."

Workshop p. 215: "So the power supply upgrade, as I mentioned, is dependent -- is a component, potentially a component of Tilbury 1B and is not required for the TLSE."

Workshop p. 216: "The power supply we have that feeds the site today is adequate to support both the regasification and the TLSE tank."

20.1 If FEI determines that additional liquefaction is necessary, indicate the maximum amount of additional liquefaction that could be installed utilizing the existing electrical system, substation, and feeders (or those that are included within the scope of the TLSE project).

Response:

As discussed in the TLSE Workshop, and referenced above, the existing 69 kV power supply to the site has adequate capacity to support the TLSE Project.

For clarity, additional liquefaction is not required within the scope of the TLSE Project. However, increased liquefaction at the site would at some point require additional power (i.e., construction of an additional power line to Tilbury).

21. Reference: Exhibit B1-4 p. 127; Exhibit A-12 BCUC IR1 30.2

Exhibit B-1-4 p. 127: "Construction of additional liquefaction is not within the scope of the TLSE Project."

Exhibit A-12 IR1 30.2: "Please explain how long it will take FEI to fill the tank to a level of 2 Bcf and 3 Bcf from empty."

21.1 Explain whether the time to fill the tank from empty varies depending on the month or season. If so, explain how it varies.

Response:

The time to fill the tank from empty does not vary depending on the month or season.

Please also refer to the response to BCUC IR1 30.1.

21.2 What does FEI consider to be an acceptable duration to refill the TLSE tank (i.e. to a level where the 3-day resiliency objective is re-established) following a no-flow or similar even that depletes most or all of the inventory?

Response:

FEI considers the ranges discussed in the response to BCUC IR1 30.1 as acceptable durations to refill the TLSE tank following a gas supply event that depletes most or all of the inventory.

21.3 Confirm or otherwise explain whether a significant draw upon the TLSE inventory of 2 or 3 BCF due to a no-flow event, coupled with the expected reduced supply following the no-flow event (e.g. due to temporarily reduced capacity of T-South) and a reserve liquefaction capacity of only 5 MMcf/d, means that it will not be possible to refill the TLSE tank and re-establish the 3-day resiliency objective until the T-South restriction is removed.

Response:

This is not confirmed, given that there are possibilities that FEI can start to refill the TLSE tank while the T-South pipeline is restricted. This scenario would likely occur if the pipeline restrictions are during a period of low gas demand (i.e., spring and summer season), because FEI may have excess T-South capacity available to help refill the TLSE tank. Refilling would be accomplished

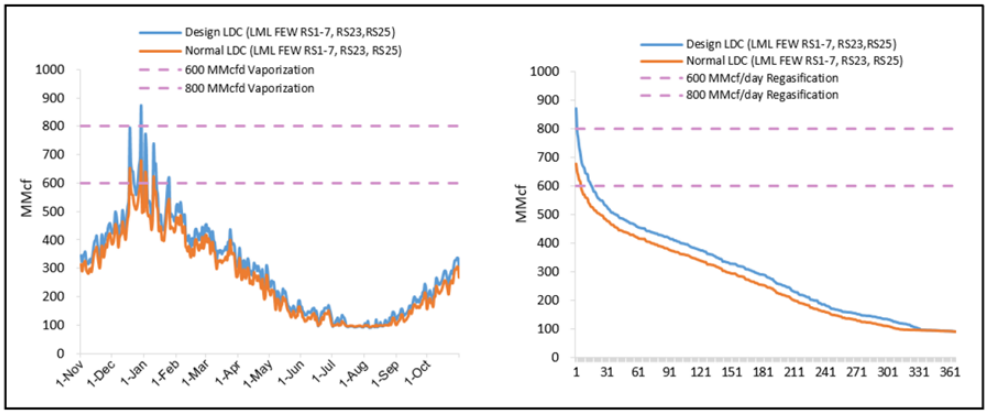
1 through a combination of the 5 MMcf/day reserve liquefaction capacity and any excess capacity
2 available at that time.

3

22. Reference: Exhibit B-1-4 pp. 60, 117-118

Exhibit B-1-4 p. 117:

Figure 4-12: Lower Mainland Load Duration Curves[103]



"Based on the load duration curve above, the design peak demand for the Lower Mainland is 871 MMcf/day for 2019/20. FEI notes that the load duration curve declines steeply, such that the second coldest day on the design load duration curve (blue) is 793 MMcf/day. The figures above demonstrate that a regasification capacity of 800 MMcf/day is adequate to cover Lower Mainland load during a complete T-South outage if it occurred on the coldest days of the winter, with the exception of the single peak design day. FEI believes regasification capacity at this level is reasonable given the remote probability of a "no-flow" event occurring simultaneously with the design peak day. Further, regasification capacity at this level will allow FEI to supply enough load so as to make it more realistic to balance the system through targeted load shedding or other emergency measures at times when it is colder."

22.1 How many days on i) the design load duration curve and ii) the normal load duration curve is 600 mmcf/d regasification insufficient to meet the load?

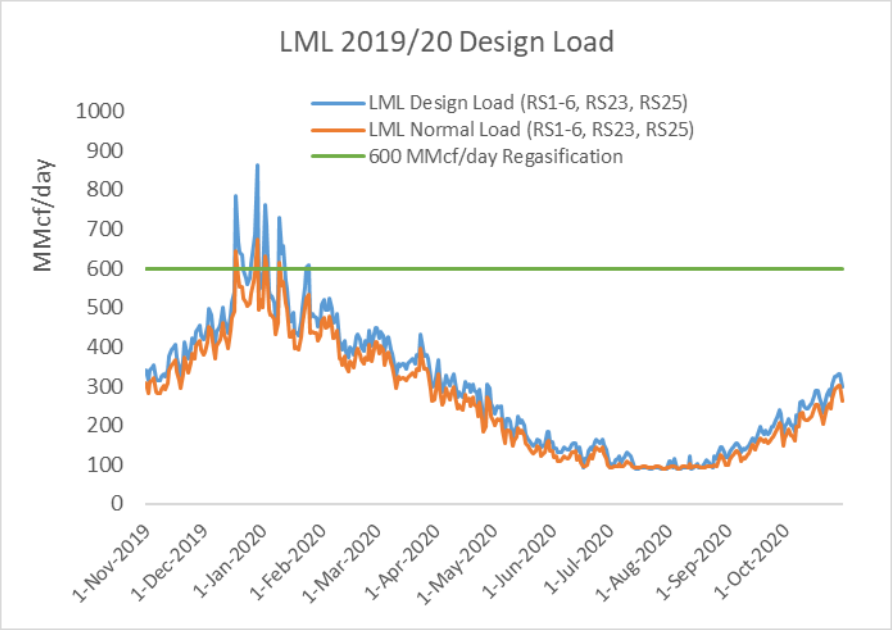
22.1.1 Confirm whether this response factors in any additional supply over and above 600 mmcf/d that may be available from linepack, mutual aid (reverse flow from the South at Huntingdon), voluntary curtailment, Tilbury Base Plant, or Mount Hayes Plant.

Response:

Based on the 2019/20 load forecast for Lower Mainland RS 1 to 6, 23 and 25 customers, there are 15 days that 600 MMcf/day is insufficient to meet the design load and five days that 600 MMcf/day is insufficient to meet the normal load.

FEI did not factor in any supply over and above 600 MMcf/day that may be available from the resources listed in the preamble because of the following reasons:

- line pack and mutual aid cannot be relied upon during a no-flow event, as discussed in the response to the BCUC IR1 11.2;
- voluntary curtailment is not a resiliency tool that can be relied upon with a timely and guaranteed response rate or demand reduction during a no-flow event;
- the TLSE Project will replace the Tilbury Base Plant, as discussed in Section 1.1 of the Application; and
- FEI cannot quantify the additional supply that may be used from Mt. Hayes because during a no-flow event that facility would be supporting the Vancouver Island system as a priority. This is further discussed in the response to BCUC IR1 11.8.



22.2 What are the expected annual growth rates in the design peak and normal winter peak?

Response:

Based on the current demand forecast, the annual growth rate for the Lower Mainland design peak and normal winter peak is approximately one percent per year on average.

22.3 In 2040, how many days on i) the design load duration curve and ii) the normal load duration curve does FEI forecast that 800 mmcf/d regasification is insufficient?

Response:

The table below provides the number of days the Lower Mainland load is above 600 and 800 MMcf/day in the 2039/40 design and normal year, assuming current load increases by one percent per year. The 800 MMcf/day regasification meets the Lower Mainland requirements except for the peak day in the design year, while 600 MMcf/day regasification is insufficient to meet the design and normal year requirements on the colder days, if a no-flow event occurs during the December to February period.

	Number of Days above Regasification Capacity	
	800 MMcf/day	600 MMcf/day
Design Year 2039/40	1 day	16 days
Normal Year 2039/40	0 day	5 days
Design Year 2019/20	1 day	15 days
Normal Year 2019/20	0 day	5 days

22.4 In 2040, how many days on i) the design load duration curve and ii) the normal load duration curve does FEI forecast that 600 mmcf/d regasification is insufficient?

Response:

Please refer to the response to RCIA IR1 22.3.

Exhibit B-1-4 p. 60: "During the T-South Incident, FEI made public appeals, starting on the evening of October 9, 2018, for customers to limit their natural gas use to the greatest extent possible…

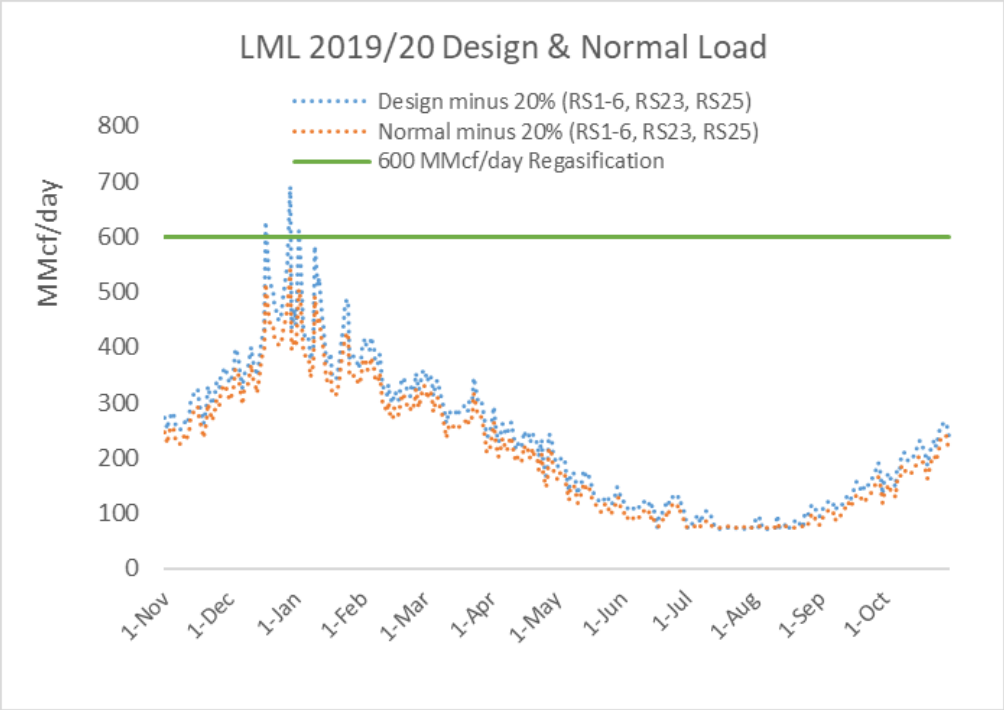
FEI has estimated that natural gas use reduced by approximately 39 MMcf/day (approximately 20 percent of expected load of 193 MMcf/day) on October 10, 2018 for customers in Rate Schedules 1 through 7 within the Lower Mainland."

22.5 Overlay design and normal load duration curves on Figure 4-12 assuming customers voluntarily curtail their consumption by 20%.

22.5.1 How many days on i) this modified design load duration curve and ii) this modified normal load duration curve is 600 mmcf/d regasification insufficient to meet the load?

Response:

Assuming customers voluntarily curtail their consumption by 20 percent, 600 MMcf/day regasification would be sufficient to meet the 2019/20 normal load requirements and would be able to meet the 2019/20 design load requirements, except for the three coldest days. This has been illustrated in the below figure. However, FEI emphasizes that, as discussed in the responses to BCUC IR1 13.3 and 19.2, voluntary curtailment is not a resiliency tool that FEI can rely on.



22.6 Provide the savings to the TLSE project if only 600 mmcf/d of regasification was installed, taking into account any incremental costs related to equipment, installation, and upgrades to ancillary systems.

Response:

Please refer to the response to BCUC IR1 19.5.

23. Reference: Exhibit B-1-4 p. 128

"The regasification system includes numerous facility components and can be thought of as the system that moves the LNG from the storage tank, converts the natural gas from its liquid state to a gaseous state, and then injects it into the CTS. The system utilizes: …

• Equipment to meter (measure) and odourize the natural gas before it is injected into the CTS."

23.1 Confirm whether gas on the Coastal Transmission System is fully odourized.

Response:

Confirmed. The odourant in the feed gas from the transmission system is removed prior to the liquefaction process, so the stored LNG itself is unodourized.

23.1.1 If so, explain the purpose of the odourization equipment that is part of the TLSE project.

Response:

Odourant is injected into the natural gas following the regasification of the LNG and prior to routing to the pipeline distribution system. Odourization of natural gas is a safety requirement in accordance with pipeline regulations. This is required so that the presence of natural gas is detectable by smell.

23.1.2 Does the Tilbury Base Plant have odourization equipment with its regasification equipment?

Response:

Yes.

D. Project Cost Estimate

24. Reference: Exhibit B-1-4 p. 138; FEI Okanagan Capacity Upgrade ("OCU") CPCN Application Exhibit B-1-2 p. 90

Exhibit B-1-4 p. 138: "FEI has set contingency and escalation amounts in addition to the Project base cost estimate to achieve a P50 confidence level to address foreseeable risks and changes in market conditions over time."

OCU Exhibit B-1-2 p. 90: "Risks with low probabilities and high consequence are not appropriately funded through contingency as they overwhelm the cost and schedule allotments. The cost associated with these types of risks are typically identified and managed as management reserves that the project team cannot spend without the Company's management's approval."

24.1 Confirm whether the TLSE project will include management reserves in addition to contingency in the project cost estimate.

24.1.1 If confirmed, identify the magnitude of the management reserves, the risks that the management reserves will address, and how the magnitude was determined.

24.1.2 If not confirmed, explain why management reserves are not included in the project cost estimate, considering management reserves were included in the Okanagan Capacity Upgrade project which has a substantially lower capital cost.

Response:

The TLSE Project does not include a management reserve. As noted in the preamble, a management reserve is required in cases where the occurrence of a risk event would consume a large portion of a project's contingency. In the case of the TLSE Project, no risk events with low probability of occurrence and high impacts were identified such that if the risk events were to occur, the Project's contingency would be inadequate or a large portion of the contingency would be used to address the risk. The TLSE project team did not identify specific risks which, if realized, would have an extreme impact on Project cost. Therefore there was no reason to include a management reserve in addition to contingency.

For the referenced Okanagan Capacity Upgrade (OCU) Project, the OCU project team identified two risk events which necessitated the allocation of a management reserve.[4] For clarity, the total estimated cost of a project is not a factor that determines the need for a management reserve but rather the need is based on the types of risk events and the consequences.

[4] Ultimately, FEI selected one management reserve for the OCU Project because the likelihood of both low probability events occurring during the project is low.

25. Reference: Exhibit B-1-4 p.146

"Construction execution plans (CEPs) will be prepared in consultation with the EPC Contractor(s) and mutually agreed upon before proceeding."

25.1 Identify the project delivery method that FEI will use for TLSE construction and explain why this project delivery method was selected.

Response:

As described in the response to CEC IR1 50.1, FEI has selected the EPC delivery method for the project. That response also describes the reasons for selecting the EPC delivery method, which are summarized as: the work will be executed by an organization with proven capability in the execution of large LNG projects; the detailed design will be done with the full involvement of construction and commissioning expertise; and, having one organization execute the work will minimize the management of interfaces on the Tilbury site, reducing overall execution risk.

26. Reference: Exhibit B-1-4 pp. 17-18; Exhibit A-12 BCUC IR1 14

Exhibit B-1-4 p. 17: "FEI has the technical capacity to undertake the Project, having designed and constructed a system of integrated high, intermediate and low-pressure pipelines as well as plant facilities associated with those pipelines."

26.1 By dollar amount, what is the largest plant facility that FEI has designed and constructed? Provide a brief summary of this project and explain why it demonstrates that FEI has the technical capacity to undertake the TLSE project.

Response:

The largest plant facility that FEI has designed and constructed is the $425 million Tilbury 1A Liquefied Natural Gas Project (T1A Project).

The T1A Project scope included gas pre-treatment, liquefaction, LNG storage, and LNG transfer to road tankers and ISO-containers, and all the other facilities required for high-reliability, safe, and efficient operation. The T1A Project was designed to operate the liquefaction system 24 hours per day, for a minimum of 345 days per year with LNG directed to the T1A tank. LNG loading from the tank to the load-out station has the capability and capacity to be operated on a 24 hours per day, seven days per week basis.

The T1A Project demonstrates that FEI has the technical capacity to undertake the TLSE Project because FEI engineering and project management staff developed the scope of work, competitively bid, evaluated, awarded, and managed the contract through to handover to operations within the approved budget.

Since the T1A Project, FEI has increased its technical capacity through growth, operating knowledge and experience. FEI has added technical capacity through the addition of experienced discipline engineers, technicians, trades, and operations staff. In addition, FEI has added the Major Projects Office staffed with experienced project management professionals who lead the development, execution, and governance of projects such as the TLSE Project.

Exhibit A-12 IR1 14: "FEI's projects currently before the BCUC requiring CPCN approval include: Pattullo Gas Line Replacement, Okanagan Capacity Upgrades, Transmission Integrity Management Capabilities (Coastal Transmission System and Interior Transmission System), TLSE, and Automated Metering Infrastructure."

Exhibit B-1-4 p. 18: "Further, when required, FEI augments its internal engineering, environmental, project management, and communications and consultation resources with experienced external consultants who provide specialist support."

26.2 Explain further why FEI is of the view that it has sufficient internal resources to undertake the TLSE project, considering the number of other projects that are expected to be undertaken in the next several years.

Response:

Please refer to the response to CEC IR1 51.1.