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September 13, 2021

Mr. James Langley
Sentinel Energy Management Inc.
PO Box 1342
Comox, BC
V9M 728

Attention: Mr. James Langley,

Dear Mr. Langley:

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 Sentinel Energy Management Inc. (Sentinel) Information Request (IR) No. 1

FEI respectfully submits the attached response to Sentinel 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

1.2 Executive Summary

Pg 35 table 1.1 subsection expansion to Northwest Pipelines Gorge capacity:

1. Explain why Northwest Pipe could not be expanded to deliver 800 million cubic feet per day to the Lower Mainland; at what cost and what would it do for system resiliency for all affected LDC's in the Pacific Northwest corridor

Response:

FEI believes that a portfolio approach is necessary to address the need for improved infrastructure resiliency. This means that on-system LNG storage and pipeline expansions are both required because they help to provide critical interrelated resiliency benefits as each separately addresses short duration and long duration supply disruptions. Please refer to the response to BCUC IR1 16.3 for additional context for this portfolio approach.

Pipeline solutions, including an expansion of Northwest Pipelines (NWP), were among the alternatives FEI considered but rejected as too costly to addressing the identified risk associated with a no-flow event on the T-South system. FEI also believes there is insufficient market interest to support the scale of such an expansion of this pipeline, requiring its cost to be borne largely by FEI. As a result, a detailed analysis of this option and cost estimate was not undertaken. An understanding, however, of issues associated with this option is important because it highlights how limited the alternatives are for addressing the regional resiliency risk given the reliance on the T-South system.

A NWP expansion of the type contemplated in this question, or any such NWP expansion to bring physical supply to the Lower Mainland, would involve reversing its north to south flow. It would also require a major expansion to bring supply from Stanfield (served by AECO/NIT supply that moves on a fully contracted flow path and by Rockies supply from a basin that is declining and costly). A variant of this alternative could involve an expansion of storage at JPS but would still require a significant Northwest Pipeline system reconfiguration.

FEI is cognizant of the resiliency risk US Pacific Northwest (US PNW) utilities face who rely on the both the T-South system and the Northwest Pipeline system. In FEI's view, it is important that a new pipeline address this resiliency risk with the development of a new flow path to the Lower Mainland and/or the Huntington delivery area as this avoids reliance on existing, well-utilized systems, while maintaining the traditional north to south flow on the north end of NWP's system.

Please also refer to the response to BCUC IR1 16.5.

Page 35 table 1.1 Subsection SCP expansion to Huntingdon

2. Explain why a new pipeline delivering to Huntingdon could not manage most of the resiliency required with managed load-shedding making up the difference. What is the right resource to manage this risk?

Response:

If a new pipeline delivering to Huntingdon was built to manage most of the resiliency requirements associated with a no-flow event on T-South during the winter, it would have to be at a significant size (800+ MMcf/day), that would ultimately be more costly for customers. This was discussed in greater detail in the response to BCUC IR1 16.3. The right resource mix to manage this risk in a cost effective manner is the combination of both the TLSE Project and a pipeline expansion (Figure 4-3 of the TLSE Application).

As discussed in Section 4.3.3, the load management capabilities that the Advanced Metering Infrastructure offers will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply side solutions, given that it does not increase supply.

Page 35 table 1.1 On system underground storage

3. Why is it not possible to build within FEI service territory and if it is a legislative hurdle what efforts has Fortis made to canvas the government changing such legislation?

Response:

FEI's Coastal Transmission System (CTS) is within the exclusion zone described in Section 4.3.5.4 of the Application; by legislation, underground natural gas storage is not permitted within this zone. FEI has not canvassed the government on this issue, but does not expect that the public or the government would be in favor of a reversal of this legislation.

Page 35 table 1 1 on system storage add a new site

4. Explain the resiliency challenges faced by other LDCs on the I-5 corridor and why resiliency facilities for such a low probability event could not be shared with these other LDCs? What efforts has Fortis made to contact other ldcs and canvas a shared resource? Please provide details.

Response:

Please refer to the response to CEC IR1 16.2.

Section 1.2.2.1.2

5. Wouldn't having on system underground storage (as opposed to above ground LNG storage) not only contribute to system efficiency but also reduce gas cost and contribute to more efficient use of the pipeline system for longer-term winter requirements?

Response:

There are some advantages to underground storage when compared to above ground LNG storage, although FEI is unsure what Sentinel means by "system efficiency". If Sentinel is referring to FEI's goal to achieve an efficient gas supply portfolio, as discussed on page 8 of the Application, this goal can be achieved via either underground or above ground storage. Regardless, FEI is unable to pursue on-system underground storage due to restrictions on this type of storage in the area surrounding FEI's CTS.

Please also refer to the response to Sentinel IR1 3.

Page 38 line 23

6. What future regional pipeline infrastructure has Fortis considered in the context of resiliency? Is Fortis aware of any imminent applications proposed by others or does Fortis have any timeline for their own applications?

Response:

Regional pipeline operators have indicated that expansions in their respective service areas are possible; however, FEI is unaware of any detailed proposals that have made it past the initial assessment stage, which includes gauging customer interest. Therefore, no applications have been brought forward to the appropriate federal, provincial or state regulator.

FEI has plans to conduct a detailed assessment to extend its existing SCP pipeline to the Lower Mainland (which FEI is referring to as the Regional Gas Supply Diversity project, or RGSD). The SCP extension from Oliver to Huntingdon would constitute a new pipeline built along a separate

corridor that is completely independent of the T-South system. Please refer to the responses to BCUC IR1 10.6 and 16.9 for more details.

1.2.3 Project Timeline Costs and Rate Impacts:

Project completion Q3 2026

Line 5 project expenditures estimated at 769 million as spent

7. Please explain “as spent”. Are there other costs to consider?

Response:

The cost estimates were completed using current dollars, i.e., in 2020 dollars in the case of the TLSE Project. As the Project will be completed over multiple years in the future, the as-spent dollars include the forecast escalation from current dollars to future dollars due to inflation as well as market conditions over time. Please refer to Section 5.4.4.5 of the Application for further details of the forecast escalation, which is completed by Validation Estimating. FEI notes the as-spent dollars also include financing costs and income tax offsets resulting from the Project deferral account costs.

Section 3 Project Need and Justification

3.1 Introduction

Para 1 The Project will provide immediate backup Supply to FEI customers primarily in the Lower Mainland……

8. What happens if pipeline break occurs between Lower Mainland and Southern Crossing? What benefit will be available to Interior customers? What if the WEI pipeline break occurs north of Savona? Will the project be able to backfeed Okanagan?

Response:

Although the TLSE Project is specifically designed to enhance the system resiliency for the Lower Mainland service area, it can provide resiliency benefits across other FEI service areas depending on the location of the event.

For example, if a pipeline break occurs between Lower Mainland and Southern Crossing Pipeline (SCP), the TLSE Project could help FEI manage such an event. FEI could divert supply off the T-South system into the Interior Transmission System (ITS) to replace the lost supply from SCP, and back fill supply from TLSE to replace the supply that was originally headed for the Lower Mainland from T-South. If the break occurs north of Savona, the TLSE Project may also help the Interior system; however, the extent of support would be limited by physical pipeline capacity. FEI's proposed Okanagan Capacity Upgrade project would improve this scenario as it will increase pipeline capacity in the south Okanagan.

3.2 .1.1 Defining Integrity line 18:

L 18. FEI manages the Integrity of its gas system assets in order to achieve its goal of zero incidents of significant consequences…

9. What actions does Fortis take to ensure the integrity of the upstream and third party gas systems that feed Fortis?

Response:

The integrity of the upstream and third-party gas systems that supply FEI are outside of the direct control of FEI. However, FEI participates in a variety of industry activities where it has periodic opportunities to engage in discussion with other pipeline operators, including on such subjects as integrity and resiliency. Further, as a firm shipper on the WEI system, FEI is a member of the WEI Toll and Tariff Task Force. The Task Force meets regularly to discuss a variety of topics, and integrity issues may be raised.

Line 22 through 30

10. Does Fortis believe they have a fiduciary responsibility in monitoring and advocating for the kind of integrity management they espouse here on third parties that are integral to Fortis supply? If yes please describe the steps Fortis takes to ensure integrity compliance. If not, who in Fortis' opinion has this responsibility?

Response:

The term "fiduciary" has a specific legal meaning that is inapplicable in this context. FEI has interpreted the question as asking about the role FEI plays in engaging with third party operators.

In FEI's experience, the transmission pipeline industry works collaboratively to prevent pipeline failures as a failure on any pipeline affects the entire industry. FEI demonstrates its commitment to industry-level integrity compliance by participating actively within the pipeline community and by participating in industry groups. This includes being an Integrity First Partner with the Canadian Energy Pipeline Association (CEPA). Senior members of FEI's System Integrity department actively participate in formal CEPA Community of Practice groups, including Pipeline Integrity, Inline Inspection, Corrosion Control, and Geohazard Management.

Participation in these groups includes conducting research, developing industry recommended practice and guidance documents, conducting benchmarking exercises, and sharing of integrity related experiences. A portion of each quarterly meeting is reserved for confidentially sharing information regarding recent failure incidents, company best practices, as well as integrity management challenges and successes. These activities contribute to integrity compliance by all members and the industry as a whole.

FEI recognizes that regulators also have an important role in ensuring integrity compliance, as a check and balance to the efforts of operators and the industry. They contribute proactively through activities including legislation development, consultation, education, and by performing assessments/audits.

Reference TSB 2018 Report Enbridge Pipeline Rupture and Fire
https://www.tsb.gc.ca/eng/rapports-reports/pipeline/2018/p18h0088/p18h0088.pdf

P 18 Integrity risk assessment report of the West Coast system completed in June 2018 identified that the 4AL2 segment of pipe had been given the second highest risk ranking for SCC.

10a. Given Fortis' statements on integrity management please confirm Fortis would prioritize rather than defer investigative examination of an area of pipe on their system defined as the second highest risk ranking for SCC on their system.

Response:

Not confirmed. Consistent with FEI's statements on integrity management, FEI's integrity management decision-making considers multiple factors including but not limited to:

- regulations and standards;
- industry practice; and
- engineering analysis, which can include ILI data analysis, system readiness assessment for ILI, and risk assessment outputs (such as a risk ranking).

FEI submits that a decision based solely on a risk ranking may not always drive prudent and cost effective integrity mitigation, and that effective decision-making requires a broader set of inputs.

3.2.1.3 p 51 line 7

FEI unable to determine which customers are receiving sufficient pressure operate safely…..

11. What resources would need to be put in place in order for Fortis to make this determination? In the case of AMI metering would it be necessary from a pressure determination perspective to have an AMI meter at every residence or could a statistically significant sample size appropriately distributed be used to make a reasonable estimation of pressures throughout the system?

Response:

The meter to be used in the proposed AMI project will not measure system pressure. The meter is installed downstream of the service regulator and, therefore, is not exposed to the system pressure.

FEI considers that installing pressure monitoring equipment at distribution stations, inlet/outlet locations and near the end of line will provide sufficient data to monitor pressure, and this scope is included as part of FEI's proposed AMI Project.

P 58 Line 30 31

Regional pipeline construction in BC and the US PNW region will only happen if large industrial projects that require natural gas come to fruition.

12. What is the status of pending large industrial projects Squamish LNG, NW innovation Works, others?

Response:

FEI assumes that Squamish LNG refers to the Woodfibre LNG project. FEI is under a non-disclosure agreement with Woodfibre LNG while they develop their project. Woodfibre LNG has stated in public that parties have expressed commercial interest in the project and have signed offtake agreements. For more information please visit Woodfibre LNG's website at https://woodfibrelng.ca/.

NW Innovation Works (NWIW) has announced that it is pausing development on the proposed methanol plant at the Port of Kalama due to an uncertain regulatory environment. The developer has notified the Port of Kalama that it will terminate its lease.

3.3.2 Load management:

Line 25 FEI expects to file an application for a CPCN to install AMI meters with remotely operable shut-off valves for the vast majority of FEI customers.

13. What is the estimated Capital cost of this initiative? What is the status of the application?

Response:

FEI filed its Application for a CPCN for the Advanced Metering Infrastructure (AMI) Project with the BCUC on May 5, 2021, and filed additional information with the BCUC on June 21, 2021. The application proceeding is expected to continue into 2022.

FEI's estimated incremental capital cost for the AMI project is $476 million. However, in the years following deployment of the AMI project, FEI expects that savings from avoided capital costs of the current meter sets as well as reduced operating costs will largely offset the project's capital cost.

Full details of FEI's AMI CPCN Application are available in Exhibit B-1 on the BCUC website at the following link: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=889

3.3.3 Ample Storage;

13a. Please provide a status update of the transport LNG infrastructure approved by the LGIC order? Is it Fortis' plan to use LNG for transport infrastructure as a resiliency tool to maintain system integrity? If not how can the existing LNG infrastructure be reconfigured in order to provide some of the resiliency Fortis seeks? Please confirm that the LGIC order approving LNG facilities for transport were in fact paid by all captive customers of Fortis through an increase in their delivery rates. If the core market customers paid for these facilities why wouldn't it be reasonable to expect they could rely on these facilities in the event of a very small likelihood of a massive system failure? Please confirm that RS 46 and any other LNG rate schedules have Force majeure clauses that allow for suspension of delivery of gas that would include failure of the supply delivery system.

Response:

The Tilbury Phase 1A facilities constructed pursuant to Order in Council 749 dated December 19, 2014 (Direction No. 5 to the BCUC), which included liquefaction capacity of up to 40 TJs per day of LNG and storage capacity of between 1.0 PJ and 1.1 PJ of LNG, were completed in 2017 and entered FEI's rate base in 2018. FEI has not yet determined to proceed with the Tilbury Phase 1B facilities, which were also approved under Direction No. 5.

As discussed in Section 5.3.3.2 of the Application, the proposed TLSE Project will be interconnected with the existing Tilbury Phase 1A facilities and is designed in such way that there is the ability to regasify and send out natural gas back into FEI's distribution system through both the TLSE storage tank and the existing Tilbury 1A storage tank. This also allows FEI to access both storage tanks in the event of a supply emergency and resiliency need. In other words, the Tilbury 1A facilities can be used in the event of a large-scale system failure, to the extent that there is LNG in Tilbury 1A at the time of the event. However, as noted in the response to BCUC IR1 11.9, FEI cannot rely on the Tilbury T1A tank from a planning perspective for resiliency purposes because FEI's LNG customers are taking LNG service, and drawing down LNG volumes in storage, in the ordinary course of business.

FEI confirms that, as part of Direction No. 5, the costs of the Tilbury 1A assets are to be included in FEI's rate base; thus, the costs of the Tilbury 1A facility are being recovered from FEI's non-bypass customers through delivery rates. However, FEI's non-bypass customers also receive the revenues from LNG sales under Rate Schedule (RS) 46.

FEI also confirms that RS 46 includes a curtailment clause which enables FEI to curtail RS 46 service by reason of *force majeure*.

14. Mount Hayes - Fortis has LNG on the island that contributes to Peak load balancing. What resiliency does it offer under the present system configuration and how can re configuring the system make material benefit to overall system resiliency? Instead of expanding the LNG system in the Urban and environmentally sensitive area of the Fraser foreshore has Fortis looked at providing resiliency to an expansion/reconfiguration of Mount Hayes? If not, why not?

Response:

Please refer to the response to BCUC IR1 11.8 for a discussion of the limited resiliency provided to the CTS by the Mt. Hayes LNG Facility. The referenced response also explains how the significant infrastructure and cost implications associated with expanding Mt. Hayes and the

interconnecting pipeline facilities to meet the Minimum Resiliency Planning Objective (MRPO) make that alternative non-feasible.

3.4.2 Interruption on T South

Page 66 lines 10 through 19

15. Given that Fortis' CTS system is in the same general geographic area as the cities of Seattle and Portland why can they not enjoy the same resiliency using Gorge capacity and Mist and Jackson Prairie storage? If the existing infrastructure is not set up to deliver US gas to the Lower Mainland at what cost would modifications be and how would such modifications help in the present situation where there is currently no more firm capacity on the Westcoast pipeline system?

Response:

Accessing gas supply either from Mist, JPS, or through the Gorge is by displacement, which requires gas to be physically flowing on the T-South system into the Northwest Pipeline system at Huntington.

Any modification or expansion to these resources (JPS, Mist, and/or Gorge) will help the present market conditions in the region under normal operations conditions, where there is currently no more firm capacity available on the Westcoast pipeline. However, to have Northwest Pipeline physically deliver gas supply to the Lower Mainland, especially during the winter season, would require a significant system reconfiguration on the north end of its system. Please refer to the response to Sentinel IR1 1, for details on why FEI considered this approach as too costly for FEI to meet its MRPO.

Page 67 line 7 to 14

15a. Why does or does not Fortis consider expanding their Southern Crossing pipeline, gaining the benefit of diversifying away from the single source of supply while simultaneously adding incremental capacity to a market hub which is presently fully subscribed? Has Fortis made any estimations of the potential gas cost savings to the core market in providing a second pipeline to the Sumas hub thereby reducing the current price volatility? Please confirm the construction of a new LNG tank is unlikely to have any significant effect on market pricing especially since Fortis plans

to use this facility to any volumetric significant quantity only in the case of a failure of supply.

Response:

FEI does consider expanding the SCP as a means to diversify away from the single source of supply and alleviate the current pipeline constrained environment in the region. This was discussed in Appendix C of the TLSE Application (Sections 3 and 5). FEI is actively exploring the option of extending the SCP to Huntingdon, (the RGSD). In FEI's view there are considerable commercial and resiliency benefits attached to such a project.

While building a second pipeline and increasing total capacity at Huntingdon could reduce the price volatility at Huntingdon, FEI cannot estimate any gas cost savings to the customers that FEI directly procures natural gas for (Rate Schedule (RS) 1 to RS 7 customers). This is because FEI's gas contracting strategy for its RS 1 to RS 7 customers in today's marketplace has limited supply priced off the Huntingdon/Sumas market (i.e., Sumas monthly or daily prices). FEI's strategy, as accepted by the BCUC in past Annual Contracting Plans, is to hold firm pipeline capacity and mitigate its fixed costs for holding such capacity whenever possible. FEI began to implement this strategy as far back as 2014 given the unfolding market conditions in the region and the broader West region. In FEI's view, this was a less risky and more prudent strategy that provided protection to customers from large price spikes, higher overall gas costs and limited availability of gas at Huntingdon. However, Sumas price volatility and increasing disconnects from Station 2 could have the effect of driving a future T-South expansion, which FEI would expect to place upward pressure on FEI's T-South tolls given the potential cost and complexity of its next expansion options. The overall cost risk to the portfolio will be considered in context of the regional constraints in FEI's expansion plans of SCP.

Building a second pipeline to Huntingdon along an entirely different path from the T-South system would allow FEI to improve resiliency while providing options and diversity for future load growth or changes in the underlying market that will unfold over time. For example, if hydrogen is introduced into the regional transmission pipelines, then FEI and the region will need more capacity to service customer needs due to the lower energy content of hydrogen.

The gas supply portfolio planning discussed above only considers a subset of the total FEI system throughput. The gas supply requirements for the remaining portion of the total system throughput are the responsibility of customers who have elected to participate in the Transportation model. These Transportation customers arrange for their own supply that is then transported by FEI to their premises. Although FEI does not procure gas on behalf of Firm Transportation customers, a second pipeline will provide significant benefits to this sector as well. In addition to providing incremental gas supply, a second independent pipeline will continue to keep gas flowing to the Huntingdon marketplace in the event of a major upset on one pipeline that leads to a long-term flow restriction. As a result, a second supply source could reduce long-term pricing volatility at the Huntingdon market, which is a major procurement hub for Transportation customers.

FEI can confirm that a new LNG tank is unlikely to have a significant effect on the market pricing at Huntingdon. The objective of the TLSE Project is to provide resiliency. FEI will keep 2 Bcf as a minimum reserve, with the remaining 1 Bcf providing additional resiliency above that minimum and flexibility to achieve gas supply and operational benefits. The additional 1 Bcf is only a modest increase to what FEI currently has from the Tilbury Base Plant, and therefore provides little impact to market pricing in the region.

Page 67 lines 21 through 28

16. Please provide examples where end of pipe utilities developed on system storage options. Does Fortis have any examples of a project approaching Fortis' cost for this proposal?

Response:

The following response has been provided by Guidehouse:

Guidehouse observes that the New England region of the U.S. provides an example of end of pipe utilities. There is no underground natural gas storage available in New England due to geographic unsuitability. There is approximately 16 Bcf of LNG storage in this region. In addition, the Everett LNG import facility provides 3.4 Bcf of storage. Much of this infrastructure was constructed in the 1970s and Guidehouse does not have the capital costs for these projects.

P 69 l 36

17. What efforts has Fortis made to ensure Westcoast provides timely information in the event of a future supply disruption?

Response:

FEI has had multiple discussions with Westcoast during and following the 2018 T-South Incident, and reinforced the importance of timely information sharing and transparency in case of any critical supply disruptions.

Similar exchanges have also occurred together with other regional shippers, customers, and pipeline companies who were all impacted by the incident. Subsequent Northwest Mutual Aid Agreement conferences have also reinforced this concern among all the member parties, of which both FEI and Westcoast are members.

As such, FEI believes the message about the necessity of Westcoast providing timely information has been made very clear. Westcoast has acknowledged this and FEI expects the sharing of information to continue.

3.4.2.2.1

Figure 3.6

18. What process changes have Fortis, Westcoast, CER made to ensure timely coordination in case of a future unexpected outage… has the CER been made aware of the capacity restraints unique to the BC service territory and has the idea of allowing gas to be turned on sooner been discussed with the regulator?

Response:

FEI maintains regular operational contact with Westcoast so that capacity and service impacts from supply disruptions are minimized. However, potential major supply disruptions arising from no-flow events on the T-South system that underpin the Application will require investments in physical infrastructure to help mitigate customer impacts.

The CER's regulation of Westcoast's systems includes overseeing activities undertaken by Westcoast to respond to failure incidents and also to ensure that Westcoast is taking appropriate steps to protect people, property and the environment; however, the CER's role does not extend to addressing the challenges to FEI and its customers associated the extent of FEI's dependency on the T-South system.

FEI has risk mitigation measures in place to address short-term and relatively minor supply disruptions that may occur on Westcoast's system. Significant no-flow events that could result in wide-scale and lengthy customer outages are best mitigated by the portfolio approach to resiliency as described in the Application.

19. In the case of another unexpected outage has Fortis coordinated with Emergency Management BC to have text messages sent to all Fortis customers to curtail gas use? If not, why not?

Response:

FEI and Emergency Management BC have discussed the possibility of utilizing the "Alert Ready" mass notification system in the event of an emergency related to FEI's infrastructure. Currently, only specific government agencies have access to Alert Ready and it is unclear as to whether there is any intent to allow municipalities or critical infrastructure operators to utilize it under emergency conditions.

Access to the "Alert Ready" mass notification system could improve the speed of delivery of messages to the public; however, more rapid messaging would not alleviate the limitations of public appeals for conservation. As described in Section 3.5.3 of the Application, public appeals for conservation have limitations related to the fact that customer demand is highly weather dependent. During cold weather, the majority of the energy used for space heating and hot water is non-discretionary and vital to the health and safety of customers. This means that customers may not respond to the curtailment requests, either by choice or because they are unable to do so. For example, care homes, hospitals, community centres, etc. are critical loads and may not be able to easily curtail their consumption.

20. Please confirm the additional dollar amount for integrity assessment management Westcoast pipeline shippers approved in Westcoast's most recent toll settlement. Please also confirm over what time period WEI has told shippers they could expect to pay these additional revenue requirements to ensure a safe and reliable pipeline.

Response:

The following table sets out the O&M and Capital integrity related costs that were agreed to in the last three negotiated settlements between Westcoast and its shippers. The most recent negotiated settlement is for 2020 and 2021.

Westcoast Negotiated Settlement Integrity Costs
Total for T-North and T-South
in $000s

	O&M	Capital[(1)]
2016	16,813	31,727
2017	19,344	45,241
2018	24,722	18,486
2019	24,613	5,618
2020	67,594	49,826
2021	56,006	38,702
Annual change		
2017	2,531	13,514
2018	5,378	(26,755)
2019	(109)	(12,868)
2020	42,981	44,208
2021	(11,588)	(11,124)

Notes
(1) Includes AFUDC.

FEI believes that Westcoast at no time indicated or implied to its shippers that the integrity costs it was seeking recovery for in 2020 or 2021 were an "additional dollar amount" for integrity assessment management required specifically in response to the 2018 rupture of the T-South system. As such, Westcoast also did not indicate a potential "time period" or that any such "additional dollar amount" would be payable by shippers.

FEI understands that the level of integrity spending required for the T-North and T-South systems over the period of the current negotiated settlement is what Westcoast believes is necessary to provide safe and reliable service.

21. Given this increased expenditure is it Fortis' understanding West Coast will have better control over the twin pipelines such that we can rely on the individual pipelines to be more reliable and to operate more independently of one another?

Response:

FEI has not assessed the impact of the additional dollar amount for integrity assessment management that Westcoast pipeline shippers approved in Westcoast's most recent toll settlement on Westcoast's control over the twin pipelines. While integrity management practices can be highly successful in identifying and mitigating against integrity-related threats, FEI

recognizes that residual integrity risk can never be zero. Similarly, FEI also recognizes that the potential for reliability events (e.g. a no-flow or reduced-flow event) can never be zero for transmission pipelines, whether due to a rupture or other cause. Please refer to the response to BCUC IR1 1.5, for a discussion of the probability of an incident occurring in the future on the T-South system based on industry data.

Please also refer to the response to BCUC IR1 1.1 which describes how the two pipelines comprising the T-South system are tied together by common headers and compressor stations and hence are operated as a single pipeline system and provide FEI with limited resiliency. This operating characteristic of the T-South system has inherent implications on its reliability and the ability of the two pipelines to operate independently of one another.

Figure 3.7 Mount Hayes provided 17% of demand on October 10th.

21a. What maximum capacity is currently available eastbound from Coquitlam compressor station?

Response:

Please refer to the responses to BCUC IR1 11.8 and Sentinel IR1 14.

Figure 3.8

The graphic shows Mutual Aid totalling [redacted] per day.

22. Given that the t south system had failed at this point please describe physically how this [redacted] was delivered to Fortis? How much of it was effectively an upstream diversion of WEI linepack and how much of it was physical gas flowing north off Northwest Pipe?

Response:

This gas supply was physically flowing north from Northwest Pipeline (NWP) into FEI's system. This was only possible because of favourable conditions (i.e., mild weather) during the no-flow portion of the T-South Incident. As discussed in Section 3.4.4.1 of the Application, FEI was able to physically access this supply because load in Washington and Oregon was sufficiently low that the physical flows could be reversed to flow north across the border. This gas was sourced from NWP line pack, Jackson Prairie Storage, and/or the Gorge supply.

3.4.2.4

23. Did any of the three "incidents of a similar nature" on the Westcoast system come close to the system impacts of the October 9th failure? Please provide volumes and duration of loss.

Response:

The following response was provided by PwC:

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

Publicly available data tends to be focused on immediate health and safety impacts (i.e., injuries and fatalities) as well as incident cause. We found limited publicly available information that would specifically characterize and allow quantification of the disruption (e.g., nature and duration of disruption, and number of customers affected).

Date	Location	Description
Oct 9, 2018	Prince George, BC	Enbridge T-South rupture **Nature of Disruption**: Major consumers curtailed (force majeure, no distinction between interruptible vs firm service) **Customers Affected**: 1 million BC, 0.8 million US **Geographic Area**: System disruption (BC and US Pacific Northwest) **Duration of disruption**: Curtailment lifted Dec, 2018 (>6 weeks), Full operational capacity resumed Dec 1, 2019 (> 1 year)
Jun 28, 2012	Buick, BC	Enbridge Nig Creek rupture **Nature of Disruption**: N/A (Pipelines were not operating at time of incident due to unplanned outage elsewhere in the system) **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: Full operational capacity resumed Sep 21, 2012 (85 days)

Date	Location	Description
Jun 23, 2012	Fort St. John, BC	Enbridge valve enclosure fire **Nature of Disruption**: N/A (Was not operating at time of incident due to planned outage) **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: Full operational capacity resumed Jul 16, 2012 (23 days)
Feb 20, 2009	Wonowon, BC	Enbridge Alaska Highway pipeline sending barrel rupture **Nature of Disruption**: No relevant information found **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: No relevant information found **Note:** Incident is believed to have occurred on non-critical system support assets (i.e., pipeline pig launcher) with limited impact to core system operations.

Additional commentary:

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

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

Page 84 line 11

24. Does Fortis have workforce sharing arrangements with other Northwest/Canadian utilities that would allow crews to aid in re-lights similar to those we have seen in the electric industry?

Response:

Please refer to the response to RCIA IR1 7.1.

3.4.6 p 84 85

25. Please provide the capital costs of Dominion Energy's LNG facility.

Response:

The following response has been provided by Guidehouse:

The capital costs of Dominion Energy's LNG facility are not available as these costs were redacted from the public record.

3.5.4.1 Tilbury

Constrained by current regasification and storage infrastructure

Page 92 line 13 re-gas at Tilbury 150 mmcf per day 17%; FEI design load of 871 mmcf

26. What would be the cost to increase re- gasification capacity at the existing Tilbury facility (using existing Peaking and 1A tanks as supply) to the design load?

Response:

Please refer to the response to Sentinel IR1 79.

Page 93 line 13

27. If the base plant at 0.6 BCF equals 17 hours of support then 1.6 BCF equals 45 hours of support; please confirm.

Response:

The 1.6 Bcf would equal approximately 45 to 46 hours of resiliency support. However, this scenario presumes both the Tilbury Base Plant and the Tilbury 1A facilities would be available for resiliency purposes, which is not an appropriate presumption for planning purposes, as discussed in Section 3.5.4.1.2 of the Application.

3.5.4.2 Mt Hayes

Page 97 line 2 Mount Hayes LNG facility is not able to support CTS requirements...

28. Did Fortis not say 44 mmcfd from Vancouver Island (Fig 3-7) was in fact used to support CTS requirements during this outage? What infrastructure rebuilds would be required to increase deliverability to CTS? Further Mount Hayes has 10 days output capacity; this is more than three times the resiliency Fortis states it needs…. what can be done to utilize this excess capacity to support the resiliency requirements of the CTS system?

Response:

FEI confirms that Figure 3-7 in the Application does indicate 44 MMcf/day was delivered into the CTS from Mt. Hayes. FEI sized Mt. Hayes appropriately with sufficient capacity to act as an on-system gas supply resource in addition to its peak shaving and resiliency capabilities mainly for the Vancouver Island system. Please refer to the response to BCUC IR1 11.8 for a discussion of the impracticability of increasing deliverability from Mt. Hayes to the CTS.

Figure 3-17 1.5 BCF regas 150 MMcfd

29. Why does excess regas capacity exist at Mt Hayes? What can be done to transfer the excess gasification capacity at Mount Hayes to Tilbury?

Response:

The regasification capacity at Mt. Hayes is appropriately sized and not in excess of that required to meet the intended purpose of the facility. Mt. Hayes was constructed to provide an on-system gas supply resource, peak shaving support, and system resiliency for the Vancouver Island Transmission System (VITS) primarily, and for the CTS, secondarily. During periods where Mt. Hayes is supporting the VITS, this reduces the amount of gas required through the CTS or from upstream suppliers. This displacement of the need to transport Vancouver Island gas though the CTS is how the Mt. Hayes regasification capacity benefits can be transferred to the CTS to support gas supply and resiliency.

3.5.4.3 FEI cannot rely on off system storage and line pack when planning for Supply emergencies….

29a. While this may be true in an absolute sense in a practical sense when a failure like this actually occurs there is almost certainly going to be some storage and line pack available. Why would Fortis ignore this in the analysis? Why not provide at least an estimate?

Response:

FEI does not ignore line pack and storage. In a real incident where access to line pack and storage exists, FEI takes full advantage of all resources in managing the response to the event. Planning resiliency investments on the basis that these resources are unavailable is a prudent approach, as a disruption on the T-South system can result in circumstances where FEI cannot access storage volumes at JPS and Mist (no northward flows at Huntingdon in Winter) and immaterial line pack is available on the T-South system (event occurring near Huntingdon). Please refer to the response to MS2S IR1 6.i where FEI provides an estimate of and discussion about the line pack in the Vancouver Island and Coastal transmission systems.

4. Description and evaluation of alternatives

Page 107 lines 21 to 27 “Pipeline capacity is expensive and it must be purchased for long durations.”

30. Given that pipeline capacity to Sumas has been fully subscribed for the last three to four years, is Fortis of the mind that incremental pipeline capacity will eventually have to be built to Sumas?

Response:

FEI does believes that new pipeline infrastructure is required in order to meet load growth, support the transition to a lower carbon economy and to enhance gas supply resiliency in the region. Further, the higher forward prices at Sumas and the West in general for the winter seasons compared to Station 2, as detailed in the response to the BCUC IR1 46.1, are also an indication that a pipeline expansion in the region is required. For these reasons, FEI is conducting a detailed assessment to extend its existing SCP to the Lower Mainland (the RGSD).

Since 2014, FEI has taken action to mitigate the risk of pipeline capacity to Huntingdon being fully contracted. This was discussed in Section 5 of the 2017 Long Term Gas Resource Plan, as well

as in FEI's Annual Contracting Plan (ACP), a gas supply planning document for RS 1 to 7 customers that is filed in the spring of each year.

For example, FEI has held contingency resources in the ACP portfolio since contracting additional T-South to Huntingdon Delivery capacity in October 2014. This was done because large-scale industrial projects (i.e., Woodfibre LNG) proposed in the region at the time secured firm transportation capacity on existing regional pipelines for a portion, if not all, of their supply requirements. Once these large projects come online, the regional gas flow and prices for all customers may be impacted. Given FEI's planning approach, FEI has likely avoided facing any supply issues to handle load growth in the short to medium term. However, there may be a significant impact on regional participants who have historically relied on interruptible transportation capacity or parties that purchase Huntingdon supply. Currently, these participants are able to serve the demand of their customers by accessing some transportation capacity in the secondary market and by purchasing more costly gas supply at the Huntingdon-Sumas market hub. In the long term, however, as new regional demand materializes, much of this capacity may be taken back to serve this new demand.

30a Is Fortis contemplating submitting a CPCN for a Southern Crossing expansion in the near future?

Response:

FEI anticipates that the earliest filing date for a CPCN application would be sometime in 2023.

30b Is Fortis aware of Westcoast offering an Open Season in the near future? Has Fortis discussed this possibility with WEI? Please describe the nature of these discussions.

Response:

FEI is not aware of any open season offering from Westcoast Energy Inc. (WEI) in the near future. FEI has not discussed the possibility of an open season with WEI because, as discussed in the response to the BCUC IR1 16.3, an expansion on T-South provides minimal resiliency benefits to FEI. This is because any future no-flow event could still disrupt the entire path through the common corridor. FEI is planning to proceed with developing a SCP expansion to Huntingdon which would entail a flow path separate from the T-South system. This type of expansion provides the greatest resiliency benefits as compared to the other pipeline expansions described in Section 4.3.4.1 of the Application.

30c Is Fortis aware of Northwest Pipe expanding their system in the I-5/Columbia gorge corridor such that incremental capacity could be available to Sumas? Has Fortis canvassed NWP on this possibility. If so please describe the nature of these discussions and if not why not?

Response:

FEI understands that Northwest Pipeline (NWP) has discussed with shippers a potential expansion of its system through the Columbia Gorge. Such an expansion would increase the physical capacity to allow for additional supply westbound through Stanfield into the I-5 corridor (i.e., into the Portland and Seattle areas). However, as discussed in the response to the BCUC IR1 16.5, this type of expansion would provide FEI with only limited resiliency benefits, especially during the winter season when physical north to south flows on NWP are critical to serving the I-5 corridor. FEI is not aware of any concrete plan by NWP to proceed with such an expansion.

30d Is Fortis aware of any other party considering a green field pipeline to enhance capacity at Sumas? If yes please describe. If any of these potential pipelines come to fruition is Fortis in agreement that such incremental capacity particularly if it was independent from Westcoast would enhance resiliency to the CTS system?

Response:

FEI is unaware of any third parties that are proposing new pipeline options for physical gas delivery to Huntingdon at this time.

30e Further if this incremental capacity existed, would it not allow Fortis to rely upon it's JPS and Mist storage contracts to provide further resiliency as displacement would likely occur as gas flows through Sumas during the outage of any one of the feeding pipelines?

Response:

The resiliency benefits that could be provided by Jackson Prairie Storage (JPS) and Mist storage during a supply disruption affecting the Lower Mainland are uncertain and likely limited. This is

because the resiliency that could be provided depends in large part on which pipeline system provides incremental physical capacity to Sumas. The amount of supply from JPS and Mist that FEI could rely upon would depend on several factors tying the amount and location of incremental pipeline capacity with the time of year and its associated demand conditions within the region.

For example, if incremental capacity was added on T-South (i.e., the situation discussed in the response to Sentinel IR1 30b), or Northwest Pipeline (i.e., the situation discussed in the response to Sentinel IR1 30c), FEI would still be dependent on physical gas flows on the T-South system to access JPS and Mist via displacement. If a future supply disruption occurred during the winter season, FEI would not be able to rely on supply from JPS and Mist via displacement.

However, if incremental capacity was added from a pipeline that follows a flow path separate from the T-South system to Huntingdon (i.e., the situation discussed in the responses to Sentinel IR1 30a), there is a greater chance that displacement on Northwest Pipeline (NWP) could continue, which may allow FEI to access some portion of its contracted supply at JPS and Mist. The amount of supply that FEI could access would be dependent on the new pipeline size (capacity per day), and how much gas is physically flowing into the NWP system during a supply disruption event. Further, FEI does not believe there is enough market support from third party shippers to build a large enough pipeline (800+ MMcf/day) that FEI could then rely upon the displacement commercial transactions during a no-flow event, specifically in the winter.

Page 108 lines 1 and 2 "..to construct a tank…"

31. In the short term, has Fortis considered using a LNG transport vessel moored at Tilbury during the winter months to provide additional storage that could then be released to transport LNG to other markets during off-peak months, until more certainty develops regarding incremental pipeline infrastructure? If not, why not and if physical or regulatory constraints prevent such use what would be the cost/likelihood of removing such constraints?

Response:

FEI has not considered the use of an LNG transport vessel moored at Tilbury to provide resiliency to the system. LNG transport vessels with the capability to transit the Lower Fraser to the Tilbury location would only be able to hold a maximum of approximately 90,000 to 100,000 metres^3 of LNG. This would be insufficient to meet the MRPO to provide resiliency to the LML. Further, this scenario would require a marine jetty as well as custom-built LNG carriers to navigate the Fraser River. FEI would either have to incur the cost to construct such a jetty and LNG carrier, or another party would have to construct it and FEI would have to pay for its use. Either of those scenarios would be more costly than the proposed TLSE Project.

4.3.1.2 As above noted pipeline infrastructure is currently at the limit of capacity and may be served by yet to be constructed pipelines.

32. What cost savings in addition to resiliency could Fortis' customers expect as increased liquidity resulting from multiple pipelines would have a downward effect on the incremental price of Sumas gas during Peak day and outage events?

Response:

As discussed in the response to Sentinel IR1 15a, FEI agrees that having multiple pipelines could have a downward effect on the Sumas price at Huntingdon. This will help customers, specifically on the Transportation model (Rate Schedules 22, 23, and 25), who rely on supply at the Huntingdon marketplace. However, FEI cannot provide a cost saving to these customers given that FEI is not responsible for procuring their supply requirements.

Although FEI has mitigated a large portion of the Sumas price risk for its Rate Schedule 1 to 7 customers as a result of Annual Contracting Plan strategies detailed in Appendix C of the TLSE Application (Exhibit B-1-3)[1], there are still significant benefits to having an additional pipeline to the Lower Mainland for all customers. Please also refer to the response to BCUC IR1 10.6 for further information on FEI's work related to a Regional Gas Supply Diversity (RGSD) solution, which would entail building a new pipeline route to the Lower Mainland connecting to the SCP in the BC interior. This project will enhance gas supply resiliency by providing needed pipeline diversity in the region, as well other benefits including to helping to serve load growth in the region and assisting with the transition to a lower carbon energy future.

P 108 l 21 -23 "...it is unlikely to be feasible or economic to attempt to manage long-duration supply events or exposures with on system LNG storage since the amount of storage required would be too large."

33. What potential long-duration supply events is Fortis referring to?

Response:

FEI is referring to the fact that after a no-flow event, the pipeline(s) would likely face operating restrictions (i.e., capacity restrictions), until it is deemed by the Regulator that it can safely operate

[1] These strategies have been addressed in FEI's 2019/20 ACP and 2020/21 ACP which have both been accepted by the BCUC via Letter L-40-19 and Letter L-31-20, respectively.

at their respective maximum operation pressures. These capacity restrictions result in less gas supply available to flow on the pipeline(s). This occurred after the T-South rupture on October 9, 2018, and is referred to in the TLSE Application as Phases two and three of the T-South Incident (Sections 3.4.2.2.2 and 3.4.2.2.3 of the Application).

4.3.2. Table 4.1

Expansion to Gorge capacity:

34. Explain why expansion of gorge capacity would require displacement. Provide approximate loads for Portland and Seattle and show capacity northbound to illustrate why gas could not move north. To the extent the Northwest Pipe currently cannot flow physically north to Sumas has Fortis approached Northwest to get an estimated cost that would allow such flows? If yes, what are those costs and if not why not?

Response:

Please refer to the responses to BCUC IR1 16.5 and Sentinel IR1 1 and 30c.

SCP expansion to Hunt:

"...new storage would still be required to supplement flows…"

35. Assuming reconfiguration at Coquitlam compressor allowing flows eastbound to CTS and expanded vaporization at Tilbury to utilize the 1 BCF tank covered by the LGIC order please provide a SCP capacity expansion that would satisfy Fortis' resiliency requirements

Response:

FEI cannot assume reconfiguration because the compressors (Eagle Mountain (V1), Port Mellon (V3), and Texada Island (V4)) are not configured to flow west to east and are not located for effective flow in that direction. Please refer to the response to BCUC IR1 11.8.

System storage at a new site

36. Would it not provide resiliency for the regional system for an LNG plant to be located very close to the Sumas interconnect such that gas could move north or south providing resiliency not only to the Lower Mainland but Washington State as well? Has Fortis approached any of the Pacific Northwest LDCs to look at construction of such a site and relevant cost-sharing? If not, why not?

Response:

FEI has not approached any of the Pacific Northwest (PNW) LDCs to evaluate such a site and relevant cost-sharing given the siting rationale discussed in the response to BCUC IR1 16.18.

4.3.4.3 Gorge

Fortis posits it would need to rely on displacement to make use of any new Northwest Pipe Gorge capacity.

37. Is it not the case additional Northwest Pipe capacity would provide additional gas supplies to the US LDCs such as Puget and Northwest Natural and to the extent that these utilities were able to rely on more gas moving West through a Gorge expansion that their ability to aid Fortis through the Northwest Mutual resiliency task force would be enhanced? Please explain.

Response:

FEI is unable to rely on the Northwest Mutual Aid Assistance Agreement (NWMAA) to meet its resiliency requirements. As discussed in Section 3.4.2.2.1 of the Application, the support provided by the NWMAA is on a best effort basis only. If there is another no-flow event on the T-South system that also occurred during the winter season, the load requirements of the Seattle and Portland areas would greatly reduce the partners' ability within NWMAA to make physical supply available to FEI at the Lower Mainland.

4.3.4.5 Expansion of SCP to Huntingdon

38. Given that the core market and other ratepayers on Fortis' system will ultimately pay for the resiliency measures Fortis seeks, what financial benefit in the form of lower gas costs did Fortis ascribe to a Sumas delivery pipeline that would mitigate the large Capital costs associated with either of the pipeline or LNG option?

Response:

As discussed in the response to BCUC IR1 10.6, FEI is completing the initial scoping and planning for a RGSD solution which would entail building a new pipeline route to the Lower Mainland connecting to the SCP in the BC Interior. The RGSD project will enhance gas supply resiliency by providing needed pipeline diversity in the region, as well as possibly alleviating the higher prices at Sumas during the winter season for customers in BC and the US PNW. Additionally, RGSD is expected to bring gas supply benefits to FEI's portfolio to mitigate the capital costs of the pipeline, in combination with the resiliency benefits for medium and longer-term events.

Please refer to the response to BCUC IR1 16.3 for additional details as to why FEI views the TLSE Project and the RGSD solution as complementary assets that form the foundation of an efficient resiliency portfolio.

4.3.4.5.1

P 117 l 1 &2.

39. Please provide historical flows that support the need to divert [redacted] per day to support interior demand.

Response:

The need to divert physical supply at Kingsvale to support the Interior demand only occurred during the T-South Incident (please refer to Figure 3-7 of the Application).

40. Please explain figure 4.5. [redacted]

Response:

[redacted]

41. Using Fortis figures would it not be [redacted] available for Sumas delivery either through existing Kingsvale connection or the new Huntingdon connection? Please explain.

Response:

Please refer to the response to Sentinel IR1 40.

4.3.5.1... p121 line 9

Guidehouse states that on system storage would provide not only a supply buffer but time to react;

42. Wouldn't having a second pipeline to Sumas not only allow a supply buffer AND provide time for Fortis to react but also allow for a continuous (if limited) flow of gas that would allow the system to limp WITHOUT catastrophic failure for an unlimited duration if weather demands? Please describe.

Response:

FEI agrees that a pipeline solution into the region could improve resiliency, while also meeting the commercial needs of the marketplace.

However, the absolute resiliency benefits that a second pipeline can bring are dependent on the pipeline size (i.e., capacity/day) and potentially the contractual arrangements to support expansion. The size of the pipeline expansion would have to be at least 800 MMcf/day in order to meet most of the design load requirements of FEI's Lower Mainland customers. While this may be technically possible, it will come at a higher cost to FEI's portfolio approach to resiliency, given that FEI's customers would have to pay a demand charge on that pipeline for capacity year round.

Although the market requires an additional pipeline to satisfy the growing demand requirements of the region during the winter while improving resiliency, the need is likely less than 800 MMcf/day.

As discussed in Section 4.3.1.2 of the Application, the most efficient resource for targeting a short duration high deliverability event is on-system storage; whereas, pipelines can be sized in a cost-effective manner to provide supply when needed during a longer period of supply disruption (duration). Please also refer to the response to BCUC IR1 16.3.

43. Storage even at 3 BCF would only provide 3.5 days of peak day demand; a second pipeline would in all likelihood provide full winter supply at design pressures. What value has Fortis ascribed to the benefit of the longer duration supply?

Response:

Please refer to the responses to Sentinel IR1 6 and 42.

4.3.5.3.1 Fortis states that the minimum storage capacity to serve the Lower Mainland can be no less than 2 BCF.

44. What is the cumulative storage currently available at Tilbury, including the 1A expansion? With cost-effective modifications to the Vancouver Island pipeline system what kind of throughput can be expected to be received from the Coquitlam compressor station? Given the excess capacity at Mount Hayes how many days can this flow be expected?

Response:

Table 3-2 below, reproduced from the Application, identifies the individual storage tanks available for the Tilbury Base Plant and Tilbury 1A. The cumulative storage at the two facilities is 1.6 Bcf. Please refer to the response to BCUC IR1 11.8 for an explanation of the throughput and supply availability from Mt. Hayes through the Coquitlam compressor station into the CTS. Modifications to permit Mt. Hayes to offer greater resiliency support to the Lower Mainland CTS system would not be cost-effective.

Table 3-2: Summary of Tilbury LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification	LM Peak Design Load
Base Plant	5 MMcf/day 120 days to fill	0.6 Bcf 0.69 days reserve	150 MMcf/day	871 MMcf/day
Tilbury 1A	28 MMcf/day 36 days to fill	1.0 Bcf Storage reserve to support RS 46 sales only	Zero	N/A - Facility designed to support RS 46 sales only

4.3.5.4 System storage in the Fraser Valley

P 125 line 31 Fortis states the principal advantages of this type of storage are low unit cost and very high-volume extra capacity. Further they state suitable geological formations may exist for on-system underground storage in the Fraser Valley area.

45. This sounds like an ideal solution; given the Fraser River delta system extends well south of the Candian US border has Fortis investigated the option of locating an underground storage facility in North Western Washington possibly partnering with PNW utilities to share cost and provide resiliency to the partners? If not, why not?

Response:

FEI has not investigated underground off-system storage in the US PNW. FEI understands that the utilities in the US PNW do not currently require additional underground on-system storage as the JPS and Mist facilities are on-system for these utilities and provide sufficient storage capacity.

Increasing LNG storage at Tilbury through the TLSE Project represents for FEI what JPS and Mist are for the US PNW utilities – on-system storage accessible even during a disruption to upstream supply. As such, FEI does not consider construction of a new underground storage facility in northwestern Washington to be a reasonable proposal.

4.3.5.5 Acquire new site for on system above ground storage,

Fortis identifies a number of advantages to the existing site (implying higher cost and potentially other issues in acquiring a new site for above-ground storage)

and 4.3.5.7 Adding Storage at existing Tilbury site,

P 130 Lines 20-30 identify the problems associated with attempting to build a greater than 3 BCF LNG plant at the existing Tilbury site.

46. Did Fortis reach out to other Pacific Northwest utilities to determine whether they also have resiliency concerns and can Fortis state categorically that the incremental cost of a greenfield site (perhaps larger than 3BCF) being shared with others (perhaps near Sumas thereby avoiding the environmentally challenging Tilbury site) would in fact be higher than the proposed Tilbury expansion covered by Fortis rate payers alone? If yes, please describe the nature of those discussions and if Fortis did not reach out, why not?

Response:

As discussed in the response to CEC IR1 16.2, FEI has ongoing discussions with the utilities in the PNW that range across a wide variety of topics, including system resiliency concerns. However, as discussed in Section 3.4.2.1 of the Application, the utilities in the US PNW are not as dependent on the T-South system in comparison to FEI's Lower Mainland service area, as they have greater physical pipeline diversity and access to more on-system storage.

The TLSE Project is specifically designed for FEI and its unique circumstances, location, and system configuration. Further, the TLSE Project also involves replacing what FEI already has within its existing portfolio of resources, (i.e., Tilbury Base Plant). Therefore, FEI did not reach out to other parties to gauge whether there was any interest in a TLSE-like resource or something similar at a greenfield site.

4.4.1.4 Criterion 4 l 20 & 21

48. Please describe how Fortis sees benefit in flexibility to accommodate future growth in light of Fortis' commitment to the government policy of 30 by 30? How can the province meet these goals while expanding natural gas use in the domestic market? Please confirm that renewable natural gas that Fortis currently forecasts in its most recent BERC filing will make up only on the order of 3% of Fortis gas stream by 2025? If this figure is incorrect please provide accurate figures referencing the BERC filing. Please provide Fortis' estimate of the percentage of RNG supply of Fortis gas supply by the year 2030. Please provide government numbers to support these values. How much of this gas will be produced within Fortis' service territory?

Response:

Flexibility is a key component of FEI being able to reduce carbon emissions on behalf of customers and helping to meet provincial emission reduction targets. As BC decarbonizes,

significant evolution of the provincial energy system will be required, which underscores the need for a resilient and reliable system to undertake this transformation. The TLSE Project is a key improvement to the resilience of the entire provincial energy system and would provide important flexibility for the system to evolve to accepting significantly more low-carbon energy.

FEI believes that expanding connections to the gas system is consistent with its long-term GHG reduction goals. Expanding the number of sectors and customers served by its gas system, making significant investments in energy efficiency to reduce overall usage per customer along with replacing the fuel delivered to include renewable and low-carbon gases are critical strategies to achieve the province's GHG reduction goals. Investments in the resilience of the gas system as FEI undertakes this transition is consistent with both FEI's and the province's objectives to deliver safe, affordable, and reliable energy to British Columbians.

FEI expects renewable gas supplies to reach a minimum 15 percent of total annual customer load by 2030, matching the government's allowed 15 percent renewable gas content set out in the recent Greenhouse Gas Reduction Regulation[2] amendments. FEI signed 13 new RNG supply contracts in 2020 and projects such that by the end of 2021, there will be contracts in place for approximately 8.5 million gigajoules of RNG – roughly 5 percent of FEI's total natural gas supply. Additionally, FEI anticipates that by 2025 it will have contracts in place for approximately 24 million gigajoules of renewable gas – over 10 per cent of FEI's total natural gas supply and enough to meet the natural gas needs of approximately 266 thousand BC homes.

At this time, these renewable supplies are anticipated to be made up largely of renewable natural gas from organic sources and hydrogen, with smaller amounts of synthetic gas and potentially the offsetting of carbon emissions from natural gas use through carbon capture and sequestration. In this way, FEI can continue to meet the growing energy needs of its customers long into the future while reducing carbon emissions.

The amount of these renewable gases produced within BC[3] and neighbouring jurisdictions that have energy systems physically connected to BC is expected to grow over time; however, the ability to purchase renewable gas from outside of BC, as has been recently approved by the BCUC, is a critical aspect of making this transition to renewable energy possible. Off-system renewable gas within BC can be similarly purchased. The carbon reduction attributes of real renewable gas projects inside and outside of BC will be purchased by FEI and delivered to customers in the same way as conventional natural gas. As a result, renewable gas content will increase over time, displacing conventional natural gas. Both renewable natural gas and

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[2] For additional information about the role of LNG and renewable natural gas in the Province's Climate Leadership Plan, please see the Government of BC's press release titled Increasing the market for LNG and renewable natural gas by visiting https://news.gov.bc.ca/releases/2017MEM0011-000790.

[3] For information on renewable natural gas potential in BC please see the 2017 Halbar Report titled Resource Supply Potential for Renewable Natural Gas in B.C., available on the BC Government's web site at: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

conventional natural gas can be stored in the Tilbury LNG Storage facility to provide all of the system flexibility benefits that are described in the Application.

With respect to the specific reference to the most recent BERC filing, FEI notes that the data for that filing was compiled more than one year ago. Since that time, FEI has made significant progress in securing new RNG supply. Further, FEI notes that it is currently undertaking a comprehensive review of its renewable gas program which will show continued evolution of expected supply.

49. With respect to Hydrogen as a supplement to pipeline natural gas in order to reduce GHGs please confirm that there are many difficulties and unknowns related to this practise including: cost to produce significant volumes of hydrogen, the potential deleterious chemical effects of hydrogen on the physical infrastructure presently used in the natural gas system (pipelines, welds, end user equipment) as well as different combustion characteristics potentially causing adverse problems in end user equipment. As such please confirm that hydrogen is at this point not a practical solution to the need to reduce GHG emissions from the natural gas stream and is unlikely to be so by 2030.

Response:

Not confirmed, FEI believes that hydrogen represents a practical solution to reduce GHG emissions associated with gas consumption.

FEI's diversified pathway analysis recognizes that low-carbon hydrogen is taking a larger role in meeting global energy needs[4]. As a gaseous fuel produced from BC's abundant resources, it will be a necessary compliment to RNG (biomethane) in meeting BC's long term goals to decarbonize the gas system. Fortunately, hydrogen offers many of the same advantages as natural gas while leveraging the benefits of the existing gas system and this perspective supports FEI plans to develop hydrogen in BC - both in helping to develop production capacity and providing the necessary transportation infrastructure needed to make hydrogen production and use economic.

However, FEI recognizes that prior to deploying hydrogen there are many factors that will need to be considered throughout multiple aspects of the gas system to ensure the reliability of the energy supply is maintained. Compared to methane, hydrogen presents different production costs, fuel properties and characteristics and the issue of safety and the perception of the risks associated with hydrogen gas supplied in the existing natural gas network or in dedicated hydrogen infrastructure are barriers that will need to be overcome.

[4] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf?sfvrsn=dbb70958_4.

To overcome these barriers the technical and economic feasibility of producing low-carbon hydrogen and distributing in the gas system to reduce the carbon intensity of the gaseous stream is being studied and tested in many different countries including Canada. FEI is involved with multiple international joint initiatives that aim to rapidly develop a hydrogen ecosystem that can produce and distribute hydrogen affordably as a clean energy supply. FEI aims to learn best practices from pioneering hydrogen projects that it hopes to apply in BC. As its understanding on hydrogen production, distribution and end-use applications develops, FEI is also working on pilot projects that will test the use of hydrogen in a closed system. FEI is also currently progressing to pre-feasibility planning and technical analyses for introducing hydrogen into the gas distribution network by 2023 and is evaluating large-scale projects for the centralized production and distribution of hydrogen.

FEI's hydrogen strategy is founded on the belief that hydrogen presents a practical solution to the need to reduce GHG emissions from the natural gas stream. This strategy is aligned with the Canada Hydrogen Strategy and the BC Hydrogen Strategy in recognizing that hydrogen offers significant new possibilities in blending with natural gas to lower emissions as well as dedicated hydrogen use in certain industrial settings or in fuel cells for transportation applications. The provincial government hydrogen strategy includes 63 actions the province intends to pursue over short, medium and long term durations. The BC Hydrogen Strategy is meant to "accelerate the production and use of renewable and low-carbon hydrogen and be a world leader in the growing hydrogen economy." The BC Hydrogen Strategy includes:[5]

Support for blending hydrogen with natural gas (2020-2025):

- Establish a regulatory framework for injecting hydrogen into the natural gas and propane distribution systems;
- Include hydrogen as a prescribed undertaking under the Greenhouse Gas Reduction Regulation; and
- Partner with a utility to review the infrastructure requirements to accommodate up to 100% hydrogen in the distribution system.

Support for hydrogen injection trials into natural gas and/or propane distribution systems (2025-2030):

- Mandate that new or modified natural gas or propane pipelines be hydrogen compatible;
- Support the introduction of hydrogen-tolerant equipment; and
- Explore the role of hydrogen in meeting the CleanBC 15 percent renewable gas target.

Support for 2030-beyond:

[5] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf.

- Support large-scale hydrogen injection into the natural gas and propane distribution systems.

50. Please provide any examples of Fortis may be aware of North American natural gas LDCs using 5% hydrogen or more in its natural gas stream delivered to customers.

Response:

FEI is only aware of Hawaii Gas as the longest standing example in North America of a LDC using more than five percent hydrogen. In the 1970s, Hawaii Gas began producing and using hydrogen to convert naphtha, a by-product from the local oil refineries, for the manufacture of synthetic natural gas (SNG) in the Campbell Industrial Park, Kapolei, on the island of Oahu. To this day, approximately 12 percent of the gas in the Hawaii Gas pipeline system on Oahu is hydrogen — this is the highest concentration of hydrogen reported by any gas utility in the U.S.[6]

Assumption: that all the problems associated with Hydrogen are overcome in the next eight years and Hydrogen becomes a significant enough component of the natural gas stream to make a material impact on GHG emissions.

51. Describe how a LNG facility with mixed gases will function given the different liquefaction and vaporization characteristics of Hydrogen and Methane. Please provide enough information that will ensure we are not building a facility that may have to be written off if hydrogen becomes the pipeline fuel of the future.

Response:

Please refer to the response to BCUC IR1 21.1 which explains that FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream and CEC IR1 42.1.1 which explains that FEI expects that the production of LNG will be compatible with the evolution of the gas supply.

When hydrogen becomes a significant component of the natural gas feedstock to Tilbury, some additional processing will be required to remove the hydrogen before it enters the LNG process. This hydrogen removal could occur upstream of the site at a different location or it could be additional equipment added at the site to remove it prior to the feed gas entering the process. Hydrogen liquefies at a much lower temperature compared to natural gas, so it must be removed

[6] https://www.hawaiigas.com/clean-energy/hydrogen/.

from the gas stream and then directed for use elsewhere. The processes for doing this are well-established and proven by industry.

P 138 Line 9 Fortis references “lower carbon gas supplies”;

52. Please define in detail what Fortis is referring to? Is Fortis aware of other significant sources of low carbon gas supplies other than RNG and Hydrogen? If so please describe what these are, what volume of these gases are presently available and what volume of these gases Fortis forecasts will be available for use in Fortis’ system by 2030? Given the age of the 2017 LTGRP and the changes to the regulatory landscape (including the increased scrutiny on GHG production and the federal mandate for increasing carbon taxes to at least 2030) please describe with updated data how Fortis hopes to achieve the provinces 30 in 30 goal while expanding natural gas use by 3.1 BCF per year (p137,l25) over the next 20 years?

Response:

Lower-carbon gas supplies refers to the portfolio of different methods that FEI will deploy to lower the carbon intensity of the gas delivered to customers and to decarbonize the overall gas system to meet FEI’s GHG emissions reduction targets.

Other potentially significant sources of low-carbon supply other than RNG and hydrogen include synthesis gas (syngas) derived from biomass, and lignin, both of which could be produced from abundant renewable resources which may be used to displace conventional natural gas at industrial gas customers’ plant operations and which FEI can also acquire as enabled by the amended Greenhouse Gas Reduction Regulation (GGRR). Further, FEI also considers carbon offsets, and new technologies that leverage the GHG reduction potential of the gas system including carbon capture as significant to its portfolio of low-carbon gas supplies.

In BC, there are abundant primary resources that have previously been evaluated regarding the specific potential to produce RNG and hydrogen.[78] The available volume of low carbon gas supplies other than RNG and hydrogen such as syngas, lignin, carbon offsets and carbon capture and sequestration is still being explored. FEI, the BC Bioenergy Network, and the Ministry of Energy, Mines and Low-Carbon Innovation are currently undertaking an integrated analysis of the

[77] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

[8] https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf.

supply potential of all low-carbon gases. At this time these energy supplies are expected to be a smaller proportion of future supply compared to renewable natural gas and hydrogen.

Please also refer to the response to Sentinel IR1 48 regarding how the TLSE Project aligns with the province's GHG reduction goals.

4.4.1.5.5 Larger tank provides the potential to reduce customer rates

"Potential" used 8 times… "could" used 6 times.

53. Please provide Fortis' opinion on the likelihood of reducing customer rates.

Response:

FEI is unable to provide an opinion on the likelihood of reducing customer rates, as the opportunity for export of LNG or offering LNG storage space, as described in Section 4.4.1.5.5, is subject to market factors. FEI notes that any such agreement for export or contracting storage space involving the regulated utility would be subject to BCUC oversight.

4.4.2.2.1

54. Please confirm RS 7 requires a turn down in 2 hours notice. If Fortis is unable to rely on RS 7 customers ability to live up to their contractual obligations should the core market offer a discount in transport rates to this group of customers?

Response:

FEI confirms that all interruptible rate schedules have a two hour notice requirement, although this would not apply in circumstances of *force majeure*. Interruptible RS 7 customers' ability to respond is no different than that of the other interruptible customers on transportation rate schedules.

Guidehouse (GH) Report

Introduction

p 242 GH states it is GH's opinion that the North American gas delivery system is highly resilient due to the large network of interconnected natural gas transmission lines that span the continent and provide capacity to enable natural gas production to reach demand centres.

55. If this is the opinion of your independent hired consultant why would Fortis not weight the benefits of interconnected pipeline resiliency over that of LNG?

Response:

The following response has been provided by Guidehouse:

Guidehouse observes that the benefits of interconnected pipeline resiliency can only be realized if two conditions are present. The first condition is that there needs to be pipeline infrastructure that is adjacent to the FEI service territory. The existing North American infrastructure provides resilience especially when multiple upstream interconnects are available. However, the region in which FEI operates does not feature multiple pipelines.

The second condition is that this pipeline infrastructure is contractually available, i.e., the physically adjacent capacity can be obtained through a contract. If pipeline assets are geographically adjacent, but fully subscribed, FEI will not be able to contract for capacity.

The following response is provided by FEI:

Please refer to the response to BCUC IR1 10.6.

Pg 245 2. "Different elements of the supply chain provide reliability and resiliency in and of themselves…"

56. Given this statement, wouldn't solving the lack of transmission line capacity be a preferred solution to two (new tank, 1A and future tanks(?)) LNG facilities at the same physical location?

Response:

No. Please refer to the response to the BCUC IR1 16.3 for the reasons why enhancing FEI's system resiliency with pipeline alone is not a cost effective approach for FEI's customers.

7. "Utilities across North America have sought and gained regulatory approval for investments related to system resiliency."

57. Does Fortis have any other examples than the two provided and specifically where LNG was the preferred solution? Please provide examples.

Response:

The following response has been provided by Guidehouse:

Guidehouse observes that the need for resiliency investments for natural gas and/or electric utilities are frequently discovered after an event has occurred. Guidehouse also observes that, Guidehouse also observes that resiliency investments must be fit for purpose and resolve specific resiliency requirements. In response to BCUC IR1 10.3, Guidehouse identifies a third example of a natural gas utility, Southwest Gas, obtaining regulatory approval for an LNG storage tank.

The following response is provided by FEI:

FEI has no other specific examples where LNG was the preferred solution beyond the two cited. However, the fact that there are no similar utility examples that FEI is aware of underscores the unique characteristics and configuration of FEI's Lower Mainland system and why the TLSE Project is needed to address FEI's specific resiliency needs.

Page 245 1.1 Resiliency in the Natural Gas Market

2nd para "... by constructing a portfolio of *natural gas transportation, on and off system storage resources and supply contracts that will enable it to address unforeseen events*." (emphasis added)

58. Of the three elements above, what would Fortis identify as the single weakest critical link in Fortis' current supply chain? Why? Please explain.

Response:

The most critical link that requires enhancement in FEI's current supply chain is on-system storage. Accessing more on-system storage provides FEI greater control to withstand and recover from an extreme event, such as a major gas supply disruption on the T-South system. As discussed in the Application, a major disruption on the T-South system is the greatest supply risk facing FEI at present.

Although additional on-system storage is the most critical need, FEI believes multiple complementary solutions are required to enhance FEI's total portfolio of resources. This is why FEI has brought forward the Application and is conducting a detailed assessment of the potential

to extend the existing SCP pipeline to the Lower Mainland (the RGSD). Expanding the SCP pipeline to the Lower Mainland will address the risk of a prolonged disruption of supply following a no-flow event, while also providing other benefits.

P 251 Linepack

2nd paragraph "A 50 mile section of 42 inch transmission line operating about 1000 PSI contains about 200 million cubic feet of gas…." using Westcoast's dual pipeline system of 36 and 30 inch suggests that given the relative cross-sections Westcoast stores 264 million cubic feet in 50 miles of pipeline.

59. Given Savona is roughly 165 miles from Sumas please confirm that guidehouse's calculations suggest there would be approximately 825 million cubic feet per day of gas in line pack available as long as any potential Westcoast rupture occurs north of Savona and further that this represents 95% of Fortis peak day load of 871 mmcfd.

Response:

Not confirmed. If Guidehouse's estimate were extended to a length of 165 miles for two parallel pipelines similar to Westcoast's NPS 30 and NPS 36 pipelines with an average pressure of 1000 psig, the volume of gas contained would be approximately 825 MMcf not 825 MMcf/day. Guidehouse's calculation is an illustration intended to show the storage potential of line pack in a pipeline system, not intended as a means of calculating the available inventory in portions of the Westcoast system. In operation, the average pressure in the Westcoast system is below 1000 psig. FEI estimates that under high demand the system from Savona to Huntingdon might contain approximately 550 MMcf. Not considering other loads supplied by the Westcoast system, FEI could deplete this line pack inventory in approximately 15 hours on a peak day.

Please also refer to the response to MS2S IR1 6.i where FEI has provided estimates of line pack in the Coastal and Vancouver Island transmissions systems. In that response FEI explained that, while useful in illustrating the volumes of gas typically contained in the systems, using the available line pack completely is infeasible if the system is to recover. The full line pack of a system cannot be used to depletion without collapsing the system to 0 psig.

1.7 Complementary Energy Systems

"Natural gas meets approximately 33% of BC end use demand…"

60. As natural gas fireplaces and space heating in general are considered to be a highly temperature dependent end use, has Fortis looked at what the effect on the peak day would be to remove these applications at the residential level? If yes, what would that Peak Day effect be? If not, why not?

Response:

Removing space heat from FEI's system would imply the very significant peak energy demand of space heating would need to move to the electrical system. Please refer to the response to MS2S IR1 4.iii for discussion of the impacts of electrification on the gas and electric systems.

61. Please provide Fortis' opinion on whether it should meet consumer demand in any way it may take form or does the utility feel it should encourage high load factor load in order to manage unit cost and pursue government policies with respect to greenhouse gas reduction?

Response:

While high load factor customers tend to 'cost less' to serve, in accordance with s. 28 of the *Utilities Commission Act*, as the sole provider of natural gas service in FEI's service territory the utility must provide service upon request. FEI has a BCUC-approved connection allowance and a system extension test that ensure connections are, on average, economic; however, there is no requirement, nor would it be fair, to serve only high load factor customers.

FEI works closely with its customers and government to reduce greenhouse gas emissions. FEI has a Conservation and Energy Management (C&EM) department that works with customers to reduce their demand, and consequently greenhouse gas emissions, through Demand Side Management (DSM) programs. FEI acts on legislation authorized under section 18 of BC's *Clean Energy Act* (CEA), particularly the enacted GGRR which enables a Public Utility to reduce customers' emissions through fuel switching from high carbon intensive fuels such as diesel to natural gas. The regulation has also enabled FEI to acquire renewable gas which has a much lower carbon intensity than conventional natural gas, thereby reducing greenhouse gases.

Page 264 Summary of Resiliency Measures in New Jersey…

62. The reasoning for this infrastructure identifies five major weather driven events in roughly 15 months, the Westcoast event was 1 in 64 years. How does Fortis see these two situations as comparable?

Response:

The following response has been provided by Guidehouse:

These situations are comparable in terms of consequence of the event. The example in New Jersey is comparable because strengthening resiliency is specifically identified by New Jersey Natural Gas (NJNG) as a driver for their investment programs and a key consideration in the decision-making process related to those investments.

Page 269 Section 2.1 Sources of Supply

63. Please confirm British Columbia produced natural gas can also be delivered to the I-5 corridor through existing and expansions of infrastructure through the Nova Gas transmission system, Foothills BC, and any existing and potential pipeline connecting Foothills to the Lower Mainland.

Response:

Confirmed.

P 271 "The Pacific Northern gas pipeline serves customers of Pacific Northern gas in West Central British Columbia….."

64. Has PNG ever suffered a failure of its supply chain? What were the effects of those failures? If those failures resulted in relights over what time period did those relights take place and how do those figures correlate with Fortis' estimates of the time necessary to re-establish service?

65. Referring to the Mar 11 web based workshop transcript p 97 l 22 to p102 l 4. Did PNG walk the entire length of all their pressurized pipelines in order to confirm there was no third-party damage before beginning the relight process? If not, please comment on why Fortis believes they should.

66. In the event of a pipeline depressurization similar to PNG's experiences, what lessons has Fortis incorporated into their own operating procedures?

Response:

The following response has been provided by Guidehouse:

Guidehouse did not examine whether or not the PNG pipeline has suffered a failure of its supply chain.

The provide response is provided by FEI:

Please refer to the response to Sentinel Confidential IR1 89.1.

Figure 15 page 274

67. Given Fortis' experience, what is more likely to mitigate the high prices experienced at Sumas in the winter: a pipeline expansion of a given daily capacity or an LNG tank of that same daily capacity? Please comment given the market will understand that the LNG tank will be used primarily as a buffer against catastrophic events.

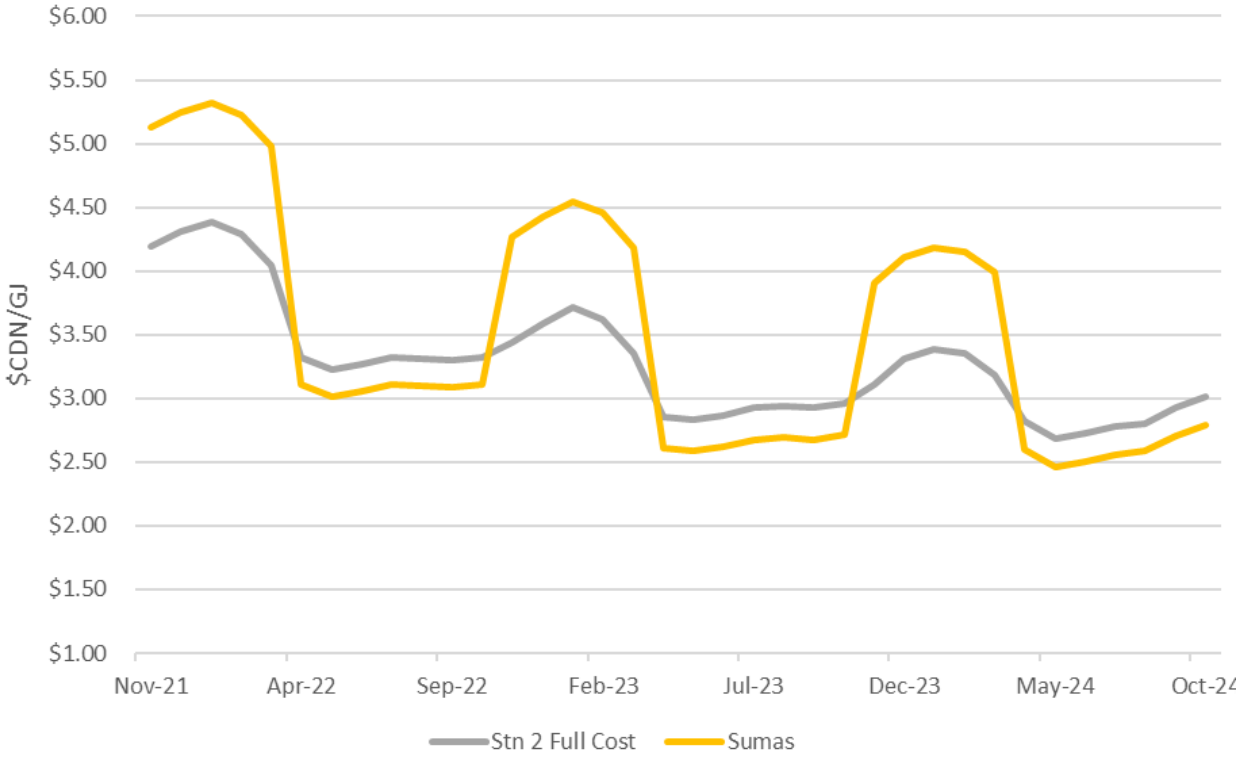
Response:

Based off the current market conditions, as discussed in the response to Sentinel IR1 30, as well as the forward prices (provided in the figure below), a pipeline expansion is more likely to mitigate the high Sumas prices in the winter. This is one of the reasons why FEI is completing the initial scoping and planning for a RGSD solution which would entail building a new pipeline route to the Lower Mainland connecting to the SCP in the BC Interior.

That said, the primary purpose of the TLSE Project is to withstand and recover from a no-flow event in the Lower Mainland, and not to mitigate the high prices at Sumas in the winter. As discussed in the response to BCUC IR1 16.3, a pipeline expansion in the region will not resolve the lack of resiliency in the Lower Mainland system that will be addressed by the TLSE Project (i.e., short duration high deliverability event).

Please also refer to the response to BCUC IR1 22.7.

Forward Market Prices (as of July 7, 2021)[9]



Page 276 Figure 16

According to this table Fortis' proposed facility would become the largest LNG facility in the region by a factor of almost three times exceeding the maximum day withdrawal of even the Mist underground storage facility.

68. Can Fortis please compare the size of the proposed Tilbury plant relative to the largest LNG *peaking facilities* operated by LDCs across North America? Can Fortis identify other North American LDCs which have the ability to serve 90% of its peak day load for three consecutive days from peaking LNG alone?

Response:

The following response has been provided by Guidehouse:

[9] Graph is based off indicative forward pricing provided by Amerex on July 21, 2021. Station 2 full costs includes Station 2 forward monthly price, Westcoast 2021 Final Tolls and the estimated T-South fuel, Motor Fuel and Carbon Tax.

In response to the question about peaking facilities, the average peak shaving facility in the U.S. has a storage capacity of 195 MMcf. Guidehouse is not aware of another North American LDC which has the ability to serve 90 percent of its peak day load for three consecutive days from LNG peaking alone. However, Guidehouse observes that a comparison of this nature does not provide an adequate evaluation. Peak shaving facilities are constructed to augment pipeline deliveries during periods of peak usage. They are not designed/sized to provide a significant portion of peak load nor are they designed/sized to serve as a backstop of an upstream pipeline failure.

P 277 1st para: ", there is not sufficient load factor to justify the economics of additional pipelines."

69. What has Fortis done to improve it's demand-side peaks in order to improve its own load factor? Compare typical hi load factor to typical low factor loads and describe what efforts Fortis has made to encourage high load factor loads and discourage low load factor loads.

Response:

The reference to the confidential Guidehouse study in the preamble is discussing PNW regional infrastructure and demand characteristics rather than those of the Lower Mainland served by the TLSE Project. Please also refer to the responses to CEC Confidential IR1 73.1 and CEC IR1 16.2 for a discussion about the relationship between solutions for resiliency that serve the Lower Mainland versus the greater PNW.

While FEI does seek out new high load factor loads such as serving new heavy duty and marine transportation demand, where market opportunities arise, FEI neither desires nor is in a position to discourage low load factor customers, such as residential and commercial heating customers, from joining the system as explained in the response to Sentinel IR1 61.

P 278 Overview of the FEI distribution system

"...FEI distribution system is comprised of multiple formerly independent systems that were combined to FortisBC Energy. "

70. Please confirm that these multiple formerly independent systems are in fact a form of resiliency themselves; that one system even given its inherent constraints can be used to support the other systems.

Response:

The degree to which any of FEI's systems can be used to provide resiliency to any of its other systems varies considerably from no support to partial support.

With respect to the Lower Mainland (LML) system (which is the relevant area addressed by the TLSE Project and the Application), FEI's systems in the Interior are entirely disconnected from the LML system. The sole interconnection between these two regions is via the Westcoast T-South system. Given that the T-South system between Kingsvale and Huntingdon can experience no-flow events which interrupt this interconnection, FEI's LML system gains no system resiliency from the Interior system.

Additionally, although the LML is connected to the Vancouver Island system by a single transmission pipeline, as discussed in the response to BCUC IR1 11.8 this system also provides no meaningful resiliency for the LML system during winter conditions.

P 280 Third Party commercial Arrangements

Last paragraph FEI has no renewal rights for Mist…

71. Please provide the date of expiration of the current Mist storage arrangement.

Response:

FEI has a variety of storage contracts at the Mist storage facility, each with different expiry dates ranging between 2024 and 2026.

72. What are the existing renewal rights that Fortis has at JPS?

Response:

FEI's contracted storage capacity at Jackson Prairie Storage expires in 2032. The contracts have bi-lateral evergreen renewal rights, which entitle each party the right to terminate the contract in its entirety by giving one year's notice.

P284 FEI should explore multiple asset configurations to mitigate the material risks like those experienced in October 2018.

73. If the requested construction of the new LNG tank proposed in this application be denied please describe what multiple asset configurations Fortis would consider in light of the preceding statement. Please provide daily delivery benefits and incremental costs for each asset described.

Response:

The following response has been provided by Guidehouse:

Guidehouse observes that FEI would need to conduct two steps. The first would be to identify geographically adjacent physical infrastructure in the region. The second step would be to determine what, if any, of this geographically adjacent infrastructure is contractually available, i.e., how much capacity is available for a long-term transportation agreement. Guidehouse observes that adjacent capacity that does not increase FEI's reliance on the T-South pipeline either does not exist or is not contractually available.

The following response is provided by FEI:

Please refer to the response to BCUC IR1 10.6.

In that response, FEI explains how it is pursuing a suite of resiliency investments aimed at the three key elements that contribute to natural gas system resiliency (Diverse Pipelines and Supply, Ample Storage, and Load Management Capabilities). If the Application for the TLSE Project is denied, there would be a resulting gap related to one of the key elements of system resiliency: Ample Storage.

Absent the approval of the Project, FEI does not have an available option or multiple asset configurations that would fill this gap.

4.1 On System Storage provides insurance by mitigating the risk of Supply disruption

74. Given the NRCC describes the likelihood of a major earthquake causing significant damage in southwestern BC is roughly 30% in 50 year time horizon (https://earthquakescanada.nrcan.gc.ca/hazard-alea/simphaz-en.php) what planning has Fortis undertaken to manage around such an event?

Response:

Please refer to the response to CEC IR1 13.1 for a description of FEI's seismic planning, evaluation, and mitigation that has been undertaken as part of its Integrity Management Program for Pipelines and LNG facilities.

FEI has also undertaken planning for post-earthquake response measures, including for its LNG facilities, as part of its emergency planning. This includes provisions for post-earthquake inspections.

75. Given the effects of a major earthquake are likely to fragment Fortis's existing interconnected CTS system into smaller isolated systems, how does locating the bulk of Fortis' on system storage in a single location contribute to mitigating risk?

Response:

Please refer to the response to CEC IR1 13.1.

76. Given the experience of Fukushima, how does locating the bulk of Fortis' on system storage in an intertidal zone contribute to mitigating risk?

Response:

Please refer to the response to CEC IR1 13.2.

77. Given that the Tilbury site is located in a typical riverine alluvial environment with significant sand deposits subject to liquefaction in the event of a major earthquake, how does the suggested Tilbury site deal with this risk? Recognizing the site will be designed according to modern earthquake construction standards, is Fortis aware of any examples where these modern standards have been tested against a large magnitude earthquake and designed structures have survived without significant damage? If yes, please provide details.

Response:

FEI has recently completed a major tank installation project (the Tilbury 1A tank), which is directly adjacent to the proposed site of the TLSE tank and auxiliary facilities. The seismic understanding of the site gained through that project provided adequate information to facilitate the early engineering for the 3 Bcf tank. Seismic studies will be carried out following BCUC CPCN approval that will further add to the knowledge of the site conditions. Additionally, FEI has safely operated the Tilbury site for 50 years.

FEI retained CB&I to carry out early engineering for the TLSE Project. CB&I have experience engineering and constructing tanks for seismically active areas, including a facility in Chile which has experienced earthquakes in 2010 and 2017. The facility includes two 160,000 cubic metre seismically-isolated tanks and a 10,000 cubic metre non-isolated tank. The epicenter of the 2010 earthquake (M 8.8) was 421 km from the facility and the epicenter of the 2017 earthquake (M 6.9) was less than 60 km from the facility; hence both represented large magnitude earthquakes. The tanks were undamaged in both earthquakes.

Page 286 A supply disruption can have a significant impact on the daily lives of FEI's customers….

See SEM Q19.

79. P287 Assuming the application process denied construction of a new LNG tank but approved Fortis' use of a combination of the existing Tilbury peaking tank and the Tilbury 1A LNG for Transport tank what would be the optimal vaporization that FEI feels should be installed to provide the maximum available resiliency with the in place assets? What would this cost be?

Response:

This scenario is not plausible given that the Tilbury 1A tank and Tilbury Base Plant tank serve different functions, as discussed in Section 3.5.4.1.2 and in the response to BCUC IR1 11.9.

Furthermore, the required regasification capacity does not change depending on the means of LNG storage at the Tilbury site. If it were possible to utilize the T1A tank or the Base Plant tank, 800 MMcf/day of vapourization would still be required in order to meet the resiliency demands of the Lower Mainland. In this scenario, a maximum of only 1.3 Bcf of LNG (this is a maximum, as it requires assuming that T1A volumes have not been depleted at all by LNG sales occurring in the ordinary course) would be available to support resiliency which would fall short of the MRPO.

B. Duty of Independence p 244

Guidehouse confirms awareness of its duty of independence. Our findings in this report are provided on an objective basis and are based on our experience, which is comprised of direct experience in the natural gas industry and providing strategic advisory services to clients in the natural gas and electric utility sector, and our review of documents provided by a FEI when requested by Guidehouse.

80. Please confirm that per the CVs provided by the authors this "direct experience in the natural gas industry" consists of 5 years of management level experience between the two authors roughly ten years ago.

Response:

The following response has been provided by Guidehouse:

Guidehouse confirms that the CVs provided by the authors are correct.

"...our review of documents provided by Fortis…."

81. Did the "review of documents (or any verbal direction) provided by FEI" suggest to Guidehouse that an LNG tank at Tilbury was Fortis' preferred solution?

Response:

The following response has been provided by Guidehouse:

Guidehouse was aware that FEI would be proposing a storage tank at Tilbury. However, it was retained to construct a framework to inform FEI's resiliency decision-making, not recommend a specific project. The Guidehouse findings in our report are provided on an objective basis and are based on our experience, which is comprised of direct experience in the natural gas industry and providing strategic advisory services to clients in the utility sector. Our analysis includes review of documents provided by FEI.

Fasken Letter

Independent expert report... independent mentioned three times.

"We request that your report set out your independent objective opinion with respect to the following questions:

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

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

82. Please confirm FEI engaged and paid Fasken and had an opportunity to review the Fasken letter of engagement to Guidehouse. Did Fortis have any concern that clauses 3 and 4 would potentially bias Guidehouse and suggest that on system storage was Fortis' preferred option?

Response:

FEI engaged and paid Fasken and had an opportunity to review the Fasken letter of engagement to Guidehouse.

FEI's initial investigations prior to this engagement made it clear that there were limited options for addressing the lack of supply resiliency to the Lower Mainland system. Given that additional on-system storage appeared to address many of FEI's resiliency needs, it was considered that having the external expert opine on the benefits from, and sizing considerations for, on-system storage would increase the value and utility of the independent objective opinion.

83. If Fortis was looking for independent advice why did the letter of engagement not read along the lines of " We believe we have a resiliency problem. Please help us out with a review of alternatives and your suggested path forward?".

Response:

Please refer to the response to Sentinel IR1 82.

Struck by how similar the arguments in GH report mirrored the statements of Fortis and vice versa.

CVs

Sabine
Director Guidehouse 2015 -
Senior Manager MNP 2012-2015

Manger ICF international 2003-2012
Environment Canada 2002 -03
2004 Bachelor of Environmental Science
2012 MBA

Moran
Assoc Dir Navigant 2015- present
Principal Wood mackenzie 2013-2015
Director Pace Global 2011-2013
Director Strategic Planning CenterPoint Energy 2006-2011
Lead analyst CenterPoint Energy 2003-2006
BA Political Science
MBA Strategy & Finance

84. Please confirm the authors have a total of 28 years in consultancy and 5 years in management level utility/gas supply chain experience.

Response:

The following response has been provided by Guidehouse:

Guidehouse confirms that the authors have a total of 28 years in consultancy and 5 years in management level utility/gas supply chain experience.

85. Please explain what form of independent advice GH was able to offer to Fortis in the various forms of resiliency applicable to an integrated gas supply chain with a relatively limited “direct experience in the natural gas industry” and no experience of any kind in operations of a gas supply chain.

Response:

The following response has been provided by Guidehouse:

The Guidehouse team is able to provide independent advice to Fortis based on its direct experience in the natural gas industry and its experience consulting to the natural gas industry. In addition, one member of the Guidehouse team, Paul Moran, served as a key author of a report commissioned by the American Gas Foundation in 2020 and completed in 2021 entitled “Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience”.

PWC letter pg 311

86. Please provide the letter of engagement between FEI and PWC.

Response:

The portions of the letter of engagement between FEI and PwC addressing the scope of services are set out below. FEI has omitted provisions related to business terms (e.g., fees, etc.), which are commercially sensitive to PwC.

Introduction

This engagement letter confirms that Fortis BC ("Client" or "you") has engaged PricewaterhouseCoopers LLP ("we" or "us" or "PwC") to perform the services described below. This letter should be read with the attached Terms of business (together the "Agreement").

- In light of recent events, notably the 2018 rupture of Enbridge's Westcoast T-South pipeline, Fortis has recognized the need to build a plan and business case for infrastructure investments aimed at improving resiliency in potential future scenarios of natural gas supply disruption.
- The first step in developing this plan, will be to gain a better understanding of the risks and impacts of potential supply disruption on Fortis stakeholders.
- Once understanding and alignment on critical risks and impacts is achieved, Fortis will be in a position to define mitigation options and develop associated business cases to inform investment decisions moving forward.

Scope of our services

You have engaged us to perform the following advisory services (the "Services"):

- Prepare and facilitate a holistic assessment, and valuation of impacts, to Fortis stakeholders that may arise as consequences of disruption to the BC natural gas market.
- Impacts to stakeholders will be derived from evaluating the potential "value and risk" trade-offs associated with distinct disruption scenarios, likelihood will not be included in the evaluation.
- Development of associated deliverables is anticipated to span a period of 6 weeks, and include collaborative engagement of both internal and external stakeholders. Kick-off of the 6 week period is Monday, June 17th, 2019.
- The 6 week engagement will be executed in a series of steps, each step producing outputs required for the subsequent step. Over the course of the engagement, two workshops will be held with appropriate stakeholders to assess our understanding and comment on any risks/dependencies relevant to outcomes prior to moving forward.

- An overview of the engagement steps, desired outcomes, and critical activities can be found below. Actual activities performed may vary slightly from described as information is gathered and stakeholders consulted.

  Step 0 - Project mobilization and kick-off

  Outcomes for this step include gaining alignment on the work plan and stakeholder group, and formalizing data needs and scheduling requirements.

  Critical activities include:

  - Develop data request and begin analysis of FortisBC strategic plan, mandate, operating environment and constraints
  - Align on preliminary list of stakeholders impacted by supply disruption and schedule interviews

  Step 1a - Internal alignment

  Outcomes of this step include engaging the internal stakeholder group and elucidating the preliminary case for improved resiliency and reliability.

  Critical activities include:

  - Analyze and understand preliminary case (or internal rationale) for improving resiliency and reliability
  - Interview internal stakeholders to understand perspectives on implications of supply disruption

  Step 1b - External assessment

  Outcomes for this step include understanding the market and external stakeholder environment and defining potential future disruption scenarios and preliminary impacts.

  Critical activities include:

  - Leverage existing assessments on the BC natural gas market and economy to identify holistic set of risks to FBC and customers, updating assessments where necessary
  - Interview external stakeholders (customers, regulator, provincial government, etc.)
  - Develop set of market scenarios and assess preliminary impacts

  Step 2 – Framework/model development

  Outcomes for this step include the development of an evaluation framework that will be utilized to assess the potential impacts of disruption scenarios.

  Critical activities include:

  - Synthesize findings and develop list of stakeholder-agnostic impact themes (social, economic, etc.)
  - Aggregate inputs to impact evaluation framework/model that includes market scenarios

Step 3 – Risk assessment

Outcomes for this step include quantifying the impacts of the future scenarios.

Critical activities include:

- Evaluate impact of risk for each stakeholder group against each market scenario
- Quantify impact

Step 4 – Develop final report

Consolidate into a final report including identification of next steps

We will provide no opinion, attestation or other form of assurance with respect to our work or the information upon which our work is based. The procedures we will be performing under this Agreement will not constitute an examination or a review in accordance with generally accepted auditing standards or attestation standards. Where the Services include consideration of future-oriented financial information, our work will not constitute an examination, compilation or specified procedures in accordance with standards established by the Chartered Professional Accountants of Canada. We will not audit or otherwise verify the information supplied to us in connection with any engagement under this Agreement, from whatever source, except as specified in this Agreement. We are not lawyers; we do not provide legal advice.

1.1 Study Background

P 318/319 Tables: Impacts by Scenario/Economic impacts by scenario and stakeholder group

87. Please provide the data used to populate Scenario 2 Commercial customers and Institutional customers and Scenario 3 Commercial customers.

Response:

The following response has been provided by PwC:

Our assessment was guided by the PwC Total Impact Measurement & Management (TIMM) framework, a holistic framework covering social, environmental, fiscal and economic dimensions that is underpinned by a common set of valuation approaches that PwC apply globally. Our assessment included primary research supported by interviews with both external (impacted sectors and other stakeholders) and internal (FEI resources). Examples of the research undertaken are provided below:

- Literature review to identify such things as mandated OH&S workplace temperatures, temperature effects on morbidity and mortality, natural gas demand patterns, and associated segmentation of stakeholders.
- 22 external interviews were conducted with a range of representative natural gas consumers and government actors. Key interview questions included: experience of past natural gas disruptions (notably the Enbridge event), the impact of an outage on operations, mitigation processes in place (e.g. backup systems), costs incurred due to the disruption, and social and environmental implications.
- 18 internal interviews were conducted across several FEI departments to learn about the province's network operations, capacity levers and constraints.

Taken together, the information collected in these interviews enabled us to understand how the range of conditions across each scenario dimension (Duration, Temperature, Area, Magnitude) would impact each stakeholder group and allowed us to perform the overall impact analysis. Working files (e.g., primary research, interview notes, economic data, etc.) were not part of PwC's deliverables for this report as is typical in these types of engagements.

These figures seem to be created on very broad assumptions with limited ability to test the embedded assumptions.

88. Does Fortis have any ability to fact check these assumptions against an actual system failure somewhere in North America? If so please provide details.

Response:

The following response has been provided by PwC:

Scenario bounds were not explicitly based on data from any major natural gas disruption events that have occurred to date. This is intentional, as the conditions under which FEI operates its natural gas infrastructure, and the nature of the impacts that would be felt, are unique. As such, whether another related system failure has occurred or not does not influence the validity of the assumptions.

Additional commentary:

- Natural gas disruption events are unique and their impact is influenced by a wide range of variables both known and unknown, precluding utility in comparison for purposes of impact assessment. Our report provided a list of recent natural gas disruption events for the purpose of highlighting that they do occur, and at a frequency that may not be widely understood.

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

89. Pacific Northern Gas has had a number of failures of their transmission system over the years due to the challenging topography of their system. Describe the significant failures of the PNG system and the costs to its customers and time to relight subsequent to their pipeline failures.

Response:

While FEI is aware of failures in the Pacific Northern Gas transmission system, it does not have access to the requested information regarding costs and customer impacts through public sources.

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90. Please provide a short paragraph for each event listed detailing the nature of the outage, the duration of the outage, how many customers actually lost gas and for how long, and the time to return to normal operation.

Response:

The following response has been provided by PwC:

Please see additional information for each event listed below:

1 **Table 1: British Columbia natural gas disruption events (2009 - 2019)**

Date	Location	Description
Oct 9, 2018	Prince George, BC	Enbridge T-South rupture **Nature of Disruption**: Major consumers curtailed (force majeure, no distinction between interruptible vs firm service) **Customers Affected**: 1 million BC, 0.8 million US **Geographic Area**: System disruption (BC and US Pacific Northwest) **Duration of disruption**: Curtailment lifted Dec, 2018 (>6 weeks), Full operational capacity resumed Dec 1, 2019 (> 1 year)
Jun 28, 2012	Buick, BC	Enbridge Nig Creek rupture **Nature of Disruption**: N/A (Pipelines were not operating at time of incident due to unplanned outage elsewhere in the system) **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: Full operational capacity resumed Sep 21, 2012 (85 days)
Jun 23, 2012	Fort St. John, BC	Enbridge valve enclosure fire **Nature of Disruption**: N/A (Was not operating at time of incident due to planned outage) **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: Full operational capacity resumed Jul 16, 2012 (23 days)
Feb 20, 2009	Wonowon, BC	Enbridge Alaska Highway pipeline sending barrel rupture **Nature of Disruption**: No relevant information found **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: No relevant information found **Note:** Incident is believed to have occurred on non-critical system support assets (i.e., pipeline pig launcher) with limited impact to core system operations.

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1 **Table 2: Rest of Canada natural gas disruption events (2009 - 2019)**

Date	Location	Description
Jan 25, 2014	Otterbourne, MB	TC Canadian Mainline rupture **Nature of Disruption**: No demand met **Customers Affected**: 9 rural MB communities **Geographic Area**: Community disruption (MB) **Duration of disruption**: Consumer supply interrupted for ~80 hrs, Engineering assessment demonstrated safe operation at reduced pressure in Oct, 2014 (>120 days)
Oct 17, 2013	Fort McMurray, AB	TC NOVA rupture **Nature of Disruption**: No demand met for two (2) major industrial consumers **Customers Affected**: Two (2) industrial consumers **Geographic Area**: Community disruption (MB) **Duration of disruption**: No relevant information on duration of customer impact, Operations resumed Nov 21, 2013 at reduced capacity (35 days), Full operations resumed Oct, 2014 (~1 year)
Feb 19, 2011	Beardmore, ON	TC Line 100 explosion and fire **Nature of Disruption**: No interruption of service to consumers (multiple parallel lines) **Customers Affected**: N/A **Geographic Area**: Community disruption (ON) **Duration of disruption**: Operations resumed Feb 20, 2011 at reduced capacity (1 day), Full operations resumed Aug 23, 2011 (185 days)
Sep 26, 2009	Marten River, ON	TC Line 100 rupture **Nature of Disruption**: No interruption of service to consumers (multiple parallel pipelines) **Customers Affected**: N/A **Geographic Area**: Community disruption (ON) **Duration of disruption**: Operations resumed immediately (multiple parallel pipelines), Full operations resumed Nov 4, 2009 (39 days)

Date	Location	Description
Sep 12, 2009	Englehart, ON	TC Line 2 rupture and fire **Nature of Disruption**: No interruption of service to consumers (multiple parallel pipelines) **Customers Affected**: N/A **Geographic Area**: Community disruption (ON) **Duration of disruption**: Operations resumed immediately (multiple parallel pipelines), Full operations resumed Dec 12, 2009 (91 days)

Table 3: Northwest US (WA, OR, ID, MT) regional natural gas disruption events (2009 - 2019)

Date	Location	Description
Mar 9, 2016	Seattle, WA	Puget Sound Energy distribution line rupture **Nature of Disruption**: No demand met **Customers Affected**: Three (3) businesses destroyed and 36 damaged **Geographic Area**: Community disruption (WA) **Duration of disruption**: No relevant information found
Mar 31, 2014	Plymouth, WA	Williams Plymouth LNG facility explosion and fire **Nature of Disruption**: No interruption of service to consumers (incident occurred within peak shaving LNG facility) **Customers Affected**: LNG peak shaving facility shut down **Geographic Area**: Regional disruption (WA / Canada) **Duration of disruption**: Full LNG operations expected to resume Apr, 2016 (>2 years)

Additional commentary:

- Publicly available data tends to be focused on immediate health and safety impacts (i.e., injuries and fatalities) as well as incident cause. We found limited publicly available information that would specifically characterize and allow quantification of the disruption (e.g., nature and duration of disruption, and number of customers affected).
- Although a disruption may have affected a specific asset for an extended period of time (e.g., loss or reduction of service), system resiliency allowed customer impact to be negligible. Our assessment scenarios make no assumption around the inherent level of resiliency in a given system.

Page 328 August 2020 Annual Contracting plan filing

Page 330 line 26.

91. Please provide a list of advantages and disadvantages in locating any new LNG storage facility at the current Tilbury site in the context of a marine bunkering LNG facility versus a system resiliency measure for the transmission and distribution system.

Response:

Section 4.3.5.5 of the Application discusses the advantages of locating the TLSE Project at Tilbury.

The TLSE Project is being constructed for resiliency purposes and is not a marine bunkering project. However, as described in Section 4.4.1.5.5, there are ancillary benefits to constructing the TLSE Project at the Tilbury site, with the potential to mitigate rate impacts.

Page 338 line 29 The ability of a natural gas system to withstand and recover from extreme or prolonged events is becoming increasingly relevant.

92. Describe how the addition of LNG infrastructure would aid in resiliency during a prolonged outage event and how that would compare to completion of additional pipeline infrastructure.

Response:

Please refer to the response to BCUC IR1 16.3.

Page 339 line 14 Ample Storage: Access to storage preferably located on a utility's own system allows a utility to manage expected or unexpected changes in supply for a period of time.

93. Please describe the duration of the period of time referenced. Please confirm that absent concerns for resiliency Fortis currently has sufficient storage for the currently expected load profile.

Response:

The desirable duration for the on-system storage resource would be enough to withstand, at a minimum, a 3-day no-flow event on the T-South system. This is the MRPO defined in the Application. FEI can confirm that it currently has sufficient storage for its current load profile, absent concerns for resiliency. However, this would change if the Tilbury Base Plant is decommissioned and the TLSE Project is not approved. This is discussed further in the response to BCUC IR1 22.7.

Page 339 line 25 Load Management

It is noted that Fortis' three elements (pipelines, storage and load management) contributing to system resiliency are all supply-side resources.

94. Please describe why Fortis does not consider the use of DSM particularly in the area of very heat-sensitive appliances (or DSM in general) as a form of load management with which to enhance system resiliency.

Response:

Please refer to the responses to BCUC IR1 13.3 and IR 19.2 and CEC IR1 27.1.

95. Given recent experience with record heat in the BC region, what effect would FEI expect on the demand for electric powered heat pumps and their use in residential heating and cooling in a generally temperate climate like British Columbia?

Response:

FEI expects that recent heating trends will result in increased adoption of mechanical cooling in residential buildings. FEI has not studied whether that increased adoption will result in electric powered heat pump adoption greater than the current market split between air conditioners and electric powered heat pumps. Furthermore, gas-powered heat pumps, which significantly improve energy efficiency over natural gas appliances and can run on renewable natural gas, are an option for customers that can also provide heating and cooling services.

96. Please confirm that typical natural gas appliances used in a residential application do not offer both heating and cooling functionality.

Response:

Natural gas appliances such as a furnace, boiler, or water heater typically installed in residential homes today only provide heat and are not designed to meet cooling loads. However, FEI anticipates that cooling will be an option in standard gas-powered heat pumps once the technology becomes commercially available beyond 2023.

Page 346 figure 3 3 Customer Load Profiles

97. Given the extreme heat sensitivity of the residential and commercial customer load, would it not add resiliency and more efficient use of fixed capital resources to shift this load over to the electric utility where arguably the use of heat pumps powered by hydro generation, wind and solar would make such energy generation carbon neutral?

Response:

FEI would still be heavily dependent on the T-South system and would need to reinvest in on-system storage to replace the Tilbury Base Plant as it reaches the end of its life. Also, while low-load factor loads can drive capital costs, shifting those loads away from natural gas would also have the effect of requiring the delivery system costs to be recovered over fewer GJs (i.e., delivery rates could increase).

As discussed below, FEI also believes that, from an overall provincial energy perspective, resiliency would worsen if heating load was migrated to the electricity system.

BC's electricity system is currently not sized to support a meaningful migration of gas heating load to electric heat pumps. Analysis conducted in the Pathways to 2050 report demonstrates that if gas customers migrated *en masse* to the electric system using efficient air source electric pumps between now and 2050, an additional 3,000 MW of clean firm generating capacity would be needed to power these heat pumps during peak heating periods. In addition to building heat load, the absolute peak would also be exacerbated by electrified transport and additional electrification in industry. All told, the Pathways Report estimated that a GHG mitigation pathway reliant on electricity would require approximately 9,000 MW of incremental clean peak generating supply which would be supplied by a mix of variable renewable generation and six large hydroelectric generating facilities (in addition to Site C). It is FEI's opinion that a carbon abatement strategy to support this outcome would be fundamentally *less* resilient based on the significant incremental infrastructure that would be required and its greater reliance on a single system and/or solution.

The findings of the Pathways Report are aligned with BC Hydro's draft IRP released this year. In that, BC Hydro evaluates the implications to achieve BC's 2030 GHG reduction target:

> Under this scenario, and after existing and committed resources, [BC Hydro] would be in a system capacity deficit in fiscal 2028 and a system energy deficit in fiscal 2024. The South Coast region would move into a capacity deficit starting in fiscal 2026.

While detail on the specific load increases associated with electrified heating are not provided in the draft IRP, the suite of measures identified in CleanBC which includes incentives and targets for greater adoption of electric heat pumps, electrified transport and electrified industry would mean an approximate 300 MW capacity deficit by 2028 (or 380 MW should expanded DSM measures not be adopted). By 2040, the end of the planning horizon, the gap between existing hydroelectric capacity and load would be greater than 4,000 MW. For comparison, the Pathways Report estimates that by 2040 the gap would be 5,000 MW for an electrification focused pathway.

This would also not be, as the question implies, more capital efficient. Maintaining a contingency reserve of up to 3,000 MW of clean, firm generation for peak heating periods could lead to significant rate pressure across the system. Peak cold periods may not materialize each year. Additional clean firm generation is significantly more costly than variable supply sources which may be sufficient to supply higher loads from annual energy load in the absence of mass electrified heating. Forthcoming research conducted at the University of Victoria outlines a range of electric supply requirements were Metro Vancouver to move to high shares of electrified heating. In the most extreme scenario where all gas load was electrified with heat pumps and where a significant peak cold weather event hit the region in line with what was experienced in 1996 in terms of temperature and duration and when provincial variable renewable capacity was not generating, then the peak resources required would be 7,000 MW of battery or some other type of electricity storage to withstand a 5-day cold period. This reserve of storage would be required to generally equate the resiliency of an electrified heating system with the gas system of today. However, the costs to install the storage required for resiliency would exceed $7 billion per year to 2050.

Please refer to Attachment 63.1 provided in the response to BCUC IR1 63.1 for more information.

98. Would this also not aid the province in its pursuit of reducing greenhouse gases? Is it not also the case that increased use of power in the province to provide heating in the commercial and residential sector (largely in the winter) would fit nicely (from a load factor perspective) with the demand profile for air conditioning for the US market (where climate change suggests cooling demand will only rise in the future) with levelized demand for carbon neutral power generation?

Response:

The scale of generation required to meaningfully displace heat provided by the gas system would be the key restriction of electrified heating. Please refer to the response to Sentinel IR1 97.

99. Has Fortis had any conversations with BC Hydro about a transition of these low load Factor loads from GHG producing natural gas to less impactful hydro, wind and solar electric generation? If not, why not?

Response:

No, FEI has not had conversations with BC Hydro about migrating residential and commercial customers for many reasons, including those discussed in Sentinel IR1 97. FEI believes that its low-carbon solutions to achieve BC's climate targets are a more beneficial approach. Please refer to Attachment 63.1 provided in the response to the BCUC IR1 63.1.

Page 347 line 10 The Region's infrastructure has been built over time to match this type of load profile with a focus on cost efficiency.

100. Rather than copy the supply-demand load management parameters relevant in the 50s 60s and 70s for use in 2020 and beyond, wouldn't it be better to take a more holistic approach to matching supply and demand balances in an era where climate change may be the most significant determinant in determining appropriate energy use? Please detail Fortis' rationale.

Response:

FEI has taken a holistic approach to strengthen the resilience of its gas delivery system and to ensure that BC's energy system is robust and capable to manage the transition to a low-carbon economy. The Pathways to 2050 report outlines that the gas system is both a key component of a decarbonized future in BC and that this system will undergo significant change.

Please refer to Attachment 63.1 provided in the response to BCUC IR1 63.1.

According to the National Law Review in the US, Seattle Council unanimously voted February 1st, 2021 to eliminate natural gas use for space and water heating in commercial and multifamily residential buildings at least four stories tall.
https://www.natlawreview.com/article/washington-state-legislature-considers-first-its-kind-state-level-natural-gas-ban

101. In light of this announcement, what can Fortis tell us about the directional need for the peaking resources in the Pacific Northwest going forward? Is it not the case that removal of this heat-sensitive demand (particularly for space heating) would directionally free up the limited availability of the storage resources Fortis argues will so desperately be needed going forward? If demand for peaking resources declined in the US PNW would these resources (existing underground storage as well as the pipeline capacity available to move the gas) not directionally be more available to Fortis to manage their low load factor peaking load? With respect to Fortis's repeated assertions that downstream storage can ONLY move by diversion is it impossible for gas to flow north from the US (with the necessary modifications to NWP facilities)?

Response:

FEI notes that as of August 30, 2021, the status of Washington State Legislature House Bill 1084 is "In Committee" and so remains under consideration. It remains unclear if the portions of HB 1084 impacting multi-family and commercial building use of natural gas for heating and hot water will be enacted in the form they are currently in. If passed into law in a form that prohibits natural gas for these uses, FEI expects that while growth in natural gas demand may be reduced, the impact on current gas demand would be minimal and slow to occur.

As in BC, gas utilities in the US PNW are making plans to decarbonize the energy they deliver to customers. It remains unclear if/how gas utility planning in the US PNW for energy efficiency and renewable gases might alter or be affected by such a law. FEI also anticipates that the electricity systems in the US PNW will have similar challenges to addressing peak demand requirements of switching large portions of natural gas peak demand to electricity as those in BC. For these reasons, it is uncertain whether House Bill 1084, if enacted, will "free up" existing storage resources in the US PNW in the foreseeable future. Given this uncertainty, FEI is unable to speculate on how this policy could affect the traditional north to south flow on the north end of NWP's system.

P 354 3.3.2 Lessons and Outcomes of the T South incident (also referencing report section 3.2.1.1 Integrity)

Line 8 the incident resulted in higher gas supply cost for all Market participants.

In its November 12th 2020 news release, (https://www.cer-rec.gc.ca/en/about/news-room/news-releases/2020/cer-issues-40-000-administrative-monetary-penalty-westcoast-energy-inc.html) the Canadian Energy Regulator CER found that "Westcoast did not follow its integrity management program for stress corrosion cracking and inspection practices and that had Westcoast done so, the pipeline defect could have been detected to avoid the rupture."

102. Based on this finding and Fortis statement regarding higher gas costs did Fortis consider suing Westcoast on behalf of its customers and shareholders. If not, why not?

Response:

While FEI can confirm that it is aware of the findings and has considered its options, FEI respectfully declines to provide the requested information. FEI's strategy regarding any potential litigation is subject to legal privilege. It is in the interests of both FEI and customers to maintain legal privilege over legal strategy.

Page 368 5.1.2 Expansion of Gorge capacity

line 14 This is because, under normal conditions FEI would need to rely on displacement or notional deliveries to receive the gas on the FEI system.

103. Please clarify. Fortis' application premises that resiliency is needed under "abnormal" conditions. Given an outage similar to the West Coast failure of October 2018 and appropriate modifications to the Northwest Pipe system would Fortis be able to receive physical gas supply northbound from the Northwest Pipe system? Please answer this question given peak day conditions, typical winter day and summer delivery conditions. Please provide an estimate of available flows for each scenario.

Response:

The TLSE Project describes a solution that is intended to address short-duration supply disruptions by providing high deliverability to the Lower Mainland (i.e., during a 3-day no-flow event). The TLSE Project will reduce the risk of widespread outages by providing sufficient supply to meet the daily demand of the Lower Mainland on all but one day in the design year.

Please also refer to the responses to BCUC IR1 16.3, 16.5, and Sentinel IR1 1, 30c, and 30e.

Review of BCUC IRs

Question 1.9

104. If a failure of the pipeline resulted from third-party damage would it be Fortis' opinion that the CER would limit the maop to the reduced levels described in the

October 18th incident or is it far more likely that if the cause of failure was not related to system integrity that we could expect MAoPs to return to normal or near normal operating conditions very soon after the cause of any future failure was determined?

Response:

Restrictions on operating pressure is a common mitigation for time-dependent threats only, but could be used by an operator or regulator to respond to any major event (e.g., third-party damage, etc.) depending on the circumstances.

A variety of site-specific considerations impact an operator's or regulator's assessment of the requirements to return to normal or near-normal operating conditions following a failure incident, regardless of cause. This includes the potential for damage to an adjacent pipeline, and any activities that may be needed to confirm the integrity of the pipeline(s). Please also refer to the response to BCUC IR1 4.3 for discussion of the potential stages following an incident and their resulting impact on an extended period of reduced capacity.

Question 1.11

105. Please describe the costs associated with the TREP project both in the most recent WEI settlement and what time horizon Westcoast has provided for the length of time associated with the project so that intervenors are aware of the total capital costs of Westcoast's trep.

Response:

FEI assumes that "TREP" refers to the Enbridge T-South Reliability and Expansion Program that is being completed and placed into service later this year.

The 2020/2021 negotiated settlement agreement between Westcoast and its shippers includes forecast capital expenditures transferred to gas plant in-service for the program, including AFUDC, of $120.847 million in 2020 and $779.410 million in 2021.

FEI understands that the economic life of the facilities associated with the T-South Reliability and Expansion Program will be the same as the economic life of the T-South system. Tolls will be set to recover the costs of the program over this time in accordance with depreciation rates that may be adjusted as circumstances, conditions, or risks change.

Question 7.3 FEI has the right to restrict service...

106. Please confirm that this right to restrict service applies equally to customers under Rate 46 or other schedules Fortis may use to provide Liquefied Natural Gas. Please confirm that rate 46 or such other LNG schedules also includes force majeure terms that amongst other things specifically allow Fortis to curtail Service as a result of a pipeline or other such supply failure.

Response:

FEI provides LNG to transportation customers under RS 46. Section 6.2 Curtailment of Dispensing Service sets the situations in which FEI may curtail service and the manner of curtailment. RS 46 also contains a definition of *force majeure* that is applicable to this rate schedule.

BCUC Q11.6

107. Please respond to the commission's questions considering the tilbury 1A tank and associated necessary regasification infrastructure as part of the asset mix.

Response:

FEI explains in the response to BCUC IR1 11.6 why it is unable to provide the requested estimates. Further, as discussed in Section 3.5.4.1.2 of the Application and in the response to BCUC IR1 11.9, the Tilbury 1A tank is intended to serve LNG Customers (i.e., RS 46 customers); therefore, FEI has no certainty that LNG would be available in the Tilbury 1A tank if needed for resiliency purposes. RS 46 customers are using LNG in the ordinary course, which depletes the volumes in the Tilbury 1A tank.

The response to Sentinel IR1 13a discusses the configuration of TLSE and Tilbury 1A.

108. In responding to BCUC 11.6 please expand upon the answers by including what improvements could be made to the existing infrastructure to extract what increased throughput for delivery to CTS during a peak day or typical winter day. Please include rough estimated costs of these improvements. (ie regas for Tilbury 1A.,Coq compressor: ability to turn around compression etc)

Response:

Section 4 of the Application describes the options considered in order to meet the MRPO, which is the goal of the TLSE Project. As on-system storage at Tilbury was determined to be the only feasible option to meet the objective, other solutions were not developed to the point where cost estimates could be produced.

109. Given load duration curves on VI relative to Mt Hayes output can excess regas at Mt Hayes be effectively moved to the Tilbury site?

Response:

Please refer to the response to BCUC IR1 11.8.

11.9

110. Please confirm the LGIC order approving construction of the Tilbury 1A assets effectively assigned the costs of construction of this facility to the core market and non bypass industrial and commercial customers.

Response:

Please refer to the response to Sentinel IR1 13a.