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November 10, 2021

Citizens for My Sea to Sky
PO Box 2668
Squamish BC,
V8B 0B8

Attention: Mr. Eoin Finn

Dear Mr. Finn:

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 Citizens for My Sea to Sky Society (MS2S) Information Request (IR) No. 2

On December 29, 2021, FEI filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-185-21 for the review of the Application, FEI respectfully submits the attached response to MS2S No. 2.

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

Issue 1: Need - event probability. A key issue in this application is the reliability of the T-South pipelines. In our IR#1 submission, we presented evidence from a gas-industry reference[1] provided in FEI's December 2020 CPCN application. That reference showed that the frequency interval for unplanned outages of North American gas pipelines averaged 428 years. The key finding of that research – derived from PHMSA's 2005-2016 Gas Distribution- Serious Incidents database- is reproduced opposite. The report highlighted that electric infrastructure is considerably more vulnerable to weather conditions such as high winds (e.g. hurricanes, tornadoes), ice storms, and other weather events. In contrast, underground natural gas pipelines have proven reliable and resilient throughout many major weather events.

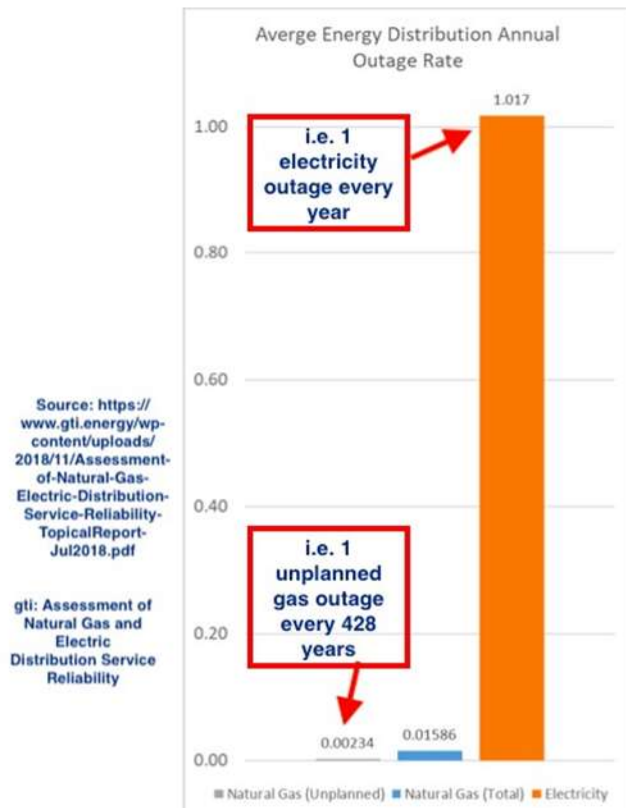


Figure 14: Comparison of Natural Gas and Electric Annual Outage Rates

In its reply to BCUC's IR#1, Fortis added some new information on this topic. JANA Corporation's "Assessment of Outage Probability" report (Attachment 1.5c), was commissioned by FEI and is dated September 9th, 2021. It explored the probability of a rupture of the T-South pipeline occurring during the economic design life of the pipeline. That lifetime was estimated by FEI to be 67 years -i.e. until A.D. 2088. It sourced its outage data from two public databases of pipeline incidents – PHMSA's and Canada's Transportation Safety Board (TSB). Using that TSB data and a Poisson distribution statistical analysis, JANA arrived at a finding that a rupture of T- South was a statistical certainty over the next 67 years of operation.

[1] https://www.gti.energy/wp-content/uploads/2018/11/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-TopicalReport-Jul2018.pdf Figure 14 of the reference. [1] Environment Canada records show the window for Vancouver's coldest days stretching ~ 40 days from early January until mid-February

We have some questions about that finding:

1.1 T-South is, physically, two pipelines, each of approximately 917 km. in length. Apart from some inter-connection/looping at compressor stations, they operate independently of one another. Yet, JANA's analysis, which calculated the rupture probability based on the 25 gas pipeline rupture incidents in the TSB database since 1990, used the combined length – 1834 km. - for its rupture incidents per 1,000 km of pipe analysis. Treating T-South as a single 1,834km.-long pipe effectively doubles the numerator in the probability calculation. Is this not an error that, corrected, should statistically predict a T-South rupture event over the next 134 years – not 67?

<u>Response:</u>

The following response was provided by JANA:

With the two pipelines in a common ROW a rupture of either pipeline, given their diameters and operating pressures, would be expected to result in a temporary shutdown of both lines until the situation could be assessed to ensure that the non-ruptured pipeline could be brought back into service (see BCSEA IR2 13.4 for further discussion). This is, therefore, considered to be a "common mode" failure situation and was treated as such in the analysis.

FEI adds the following clarification:

FEI disagrees with the statement in the question that the two pipelines "operate independently of one another". The two pipelines operate together as a common pipeline system, as reflected in the fact that the pipeline owner (Enbridge) refers to it in the singular as "T-South, the southern mainline of the BC Pipeline, connects production from northeastern B.C. to downstream markets within B.C. and export markets in the U.S. Pacific Northwest."[2]

1.2 As FEI has indicated[3] in its response to MS2S' IR#1 (P. 4), for at least 241 of the warmer days of the year in SW BC, a no-flow rupture would not stop gas service to customers – the current 0.6 Bcf tank at Tilbury could, with some regasification enhancements, bridge a 3-day no-flow outage event. If so, does that not further shrink the requirement for the resiliency tank – changing the probability of needing it from one in 134 years to one in 280 years (134 x 241/115)?

[2] https://www.enbridge.com/~/media/Enb/Documents/Factsheets/BC%20Pipeline%20Factsheet.pdf

[3] FEI stated that "…..there is an approximate 151-day winter period when the current 0.6 Bcf tank at Tilbury could not bridge a 3-day no-flow supply emergency

Response:

JANA confirmed in the response to MS2S IR2 1.1, due to the potential for common-mode failures (i.e., a failure of one T-South pipeline impacting the adjacent pipeline), it is appropriate to treat the T-South system as a single 1,834 km pipeline system. As such, the reduced probability premised in the question (i.e., "one in 134 years") is incorrect. The way in which the change in cumulative probabilities has been calculated in the question is also incorrect.

Please also refer to the response to BCUC IR2 78.1 which, among other things, addresses the impracticality of executing what the question refers to as "some regasification enhancements" on their own while continuing to use the Base Plant storage tank.

1.3 Following on from the previous question, counting (i) supply from SCP; (ii) regas flowback from Mount Hayes; (iii) ; linepack in the CTS and (iv) CNG truckload injections into the CTS, for how many days in an average year would the resiliency tank be needed?

Response:

In order to be responsive, FEI has provided an answer to this hypothetical scenario; however, there are at least two assumed sources of supply suggested in the question above that cannot be relied upon to address the risk of a no-flow event:

- **Line Pack in FEI's Coastal Transmission System (CTS):** As discussed in the response to MS2S IR1 6i, it is not possible operationally to completely expend the line pack and then continue operating the system, as a hydraulic collapse would have already occurred. Rather, FEI would only be able to expend a small fraction of the line pack in each daily peak period, and would have to rebuild this daily during off-peak periods from any available supplies in order for the system to continue to function. Therefore, FEI has not included any line pack volume in this scenario as it is not technically feasible.
- **CNG Truckload Injections into the CTS:** FEI cannot rely on CNG truckload injections into the CTS because this resource is not available on short notice (i.e., it is not on continuous standby waiting for a no-flow event to occur). Setting up both the compression and decompression/reinjection sites could take several weeks, as demonstrated when FEI trucked CNG from the Interior to the Lower Mainland in December 2018 (during the T-South Incident). Further, the amount of CNG provided by these truckloads is inconsequential when compared to the overall demand on FEI's system, particularly in winter. As discussed in the response to BCUC IR1 68.2, during the months of December 2018 and January 2019, the amount of CNG that was trucked into the Lower Mainland was approximately 408 MMcf, which is equivalent to 6.5 MMcf/day (i.e., approximately 1 percent of FEI's peak day load which exceeds 600 MMcf/day).

Explanation of Scenario Assumptions

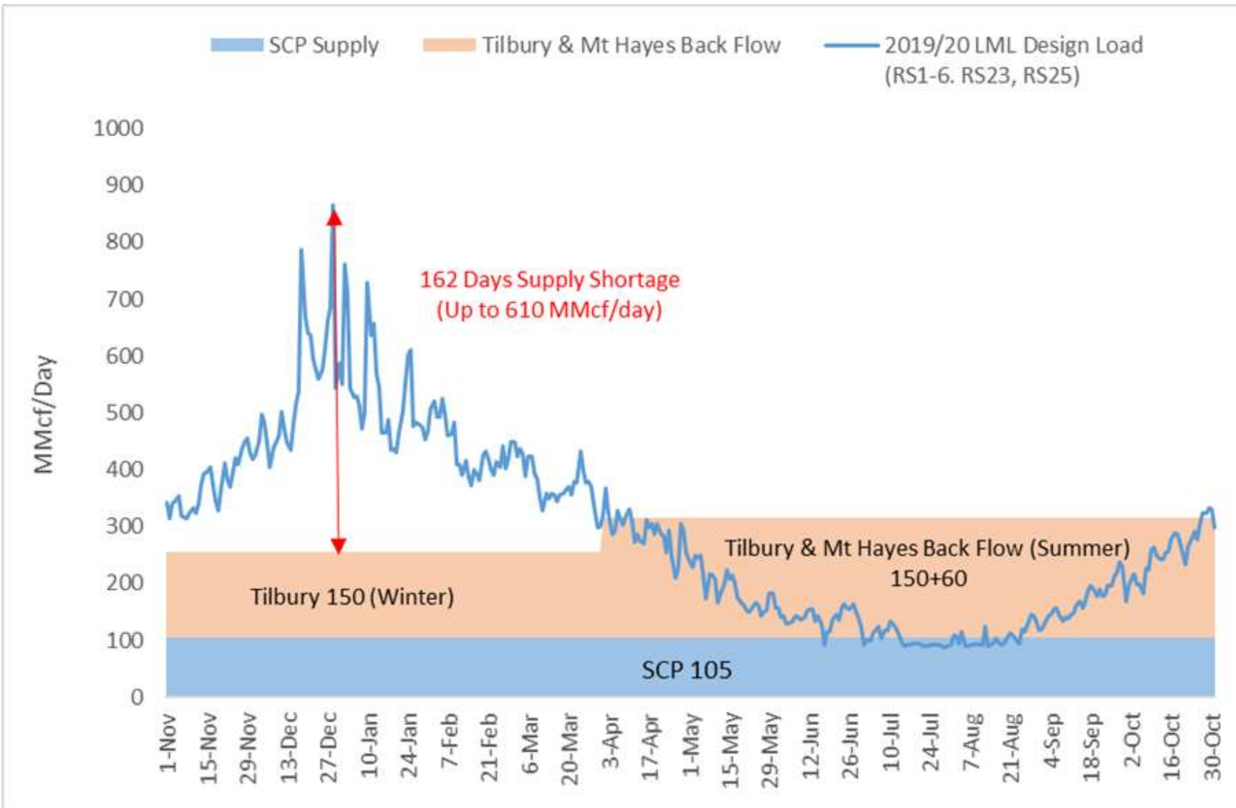
FEI's assumptions for this analysis are set out below, along with further discussion about why certain assumptions may be impractical during a no-flow event:

1. The analysis performed below assumes that 0.6 Bcf is available from the Base Plant. Although the design capacity of the Base Plant tank is 0.6 Bcf, FEI is currently operating the tank at a reduced capacity while it assesses the future operability of the tank (as explained in Section 3.5.4.1.2 of the Application). The assumption that the entire 0.6 Bcf is available also departs from the way that the Tilbury Base Plant currently operates, which is to serve peak demand and/or other operational related purposes.
2. As discussed in the response to BCUC IR1 11.8.2, the Vancouver Island Transmission System (VITS) and the Mt. Hayes facility have some ability to support resiliency in the Lower Mainland during warmer times of the year. Under favourable warm-weather conditions, Mt. Hayes can provide up to 60 MMcf/day of supply by reversing gas flows in the VITS. During the winter season, the VITS would provide no meaningful support to the Lower Mainland during a no-flow event on the T-South system. Therefore, the analysis below assumes that the Mt. Hayes LNG is able to backfeed the Lower Mainland 60 MMcf/day during the summer period only (i.e., April to October).
3. FEI has included the entire 105 MMcf/day that the existing Southern Crossing Pipeline could provide to the Lower Mainland during a no-flow event. FEI discussed the reasons why this volume may not be available during a no-flow event on the T-South system in the response to BCUC IR1 11.11. This includes the following factors:
    - the status of Westcoast's T-South to Savona or other delivery points north of Kingsvale;
    - the load requirements of the Interior system; and
    - the operating conditions of the T-South system south of Kingsvale.

This hypothetical scenario is still limited to the 150 MMcf/day of regasification capacity currently available at the Tilbury site. As discussed in the response to BCUC IR2 78.1, it is not practical to add regasification to the Base Plant, and even if (hypothetically) the Base Plant was not constrained by regasification capacity, 0.6 Bcf of storage would be insufficient to supply the Lower Mainland during a winter no-flow event.

As shown in Figure 1 below, based on FEI's 2019/20 load forecast and the considerations provided above, the TLSE Project would be required for 162 days during the year. This hypothetical scenario reinforces why FEI needs both additional regasification capacity and storage at Tilbury for resiliency purposes (i.e., a minimum of 2 Bcf of storage and 800 MMcf/day of regasification).

Figure 1: Single Day Capacity View: 162 Days of Supply Shortfall Without the TLSE Project



1.4 Only about half (13) of the 25 transmission pipe rupture incidents in the TSB database were associated with ignition of the escaping gas (the 2018 incident was one such – the fireball on the 30" pipe scorched the casing on the adjacent 36" pipe). Given that the danger to an adjacent pipeline is significantly lessened where ignition does not accompany a rupture, would that further reduce the likelihood that both pipelines would be placed out of service, making for a shorter no-flow interval? Is there an industry statistic for that ignition/no-ignition effect?

Response:

The following response was provided by JANA:

The analysis considered both the cumulative probabilities of total ruptures and ignited ruptures to provide a higher and lower end bound for outage probabilities as detailed in the JANA Report: Assessment of Outage Probability.

Any rupture of a 30" or 36" NPS transmission pipeline would be expected to result in an outage of at least two days duration and most likely three days or greater followed by some period of reduced capacity on the lines, whether the rupture ignites or not. Ignition events do tend to result in slightly longer outages. For PHMSA reported ruptures for pipelines 30" NPS or greater with reported outage durations, 100% had an outage duration ≥ 2 days (26 of 26) and 96% ≥ 3 days (25 of 26). For ignited ruptures, 100% of reported incidents had outage durations ≥ 3 days (20 of 20). Of the 4 TSB reported ruptures with outage durations for pipelines 30" and greater, 3 of 4 were ≥ 2 days and 2 of 4 were ≥ 3 days. For ignited ruptures, 100% of reported incidents had outage durations ≥ 2 days and 2 of 3 ≥ 3 days.

For the 2018 T-South incident, based on the TSB "Pipeline Transportation Safety Investigation Report P18H0088", the NPS 36 L2 pipe ruptured. The coating was damaged on the adjacent Western NPS 12 pipeline (crude oil pipeline). The NPS 30 L1 pipeline was not exposed during the occurrence. Even through the NPS 30 L1 pipeline was not exposed, it was still taken out of service. After a rupture of one pipeline in a shared ROW, a likely outcome is that the adjacent pipeline would be taken out of service, such as was done in the case of the T-South incident, until an investigation can be conducted to ensure a base level of integrity of the pipeline. This would be expected to occur for ruptures on pipelines the size of the two T-south pipelines whether the gas released from the rupture ignites or not and that is why the assessment considered a rupture as a "common mode" failure that would result in a loss of flow for both pipelines. It is also expected that the pipelines would be returned to service at reduced capacity (e.g. 80% of previous operating pressure) until further integrity verifications are completed (as was done for both of the T-South pipelines when they were brought back into service).

The analysis was based on the average industry values for ruptures and ignited ruptures (i.e., it was based on historical industry statistics).

Issue 2: "Hydraulic Collapse". Throughout its December, 2020 CPCN application, FEI has referenced this possibility as a worst-case outcome of a prolonged no-flow event on T-South, requiring a labour- intensive and lengthy program of pipe venting and re-lights of customer equipment as part of recovering from a no-flow T-South outage. We have tried to research this phenomenon on the Internet and in industry publications, and come up empty on the subject. We simply cannot find an incidence where this has happened to a major gas distribution system – at least under that descriptor. **Our questions**:

2.1 Is there a more common name for the phenomenon?

Response:

The term "hydraulic collapse" is one of many ways to refer to the process or sequence of events resulting in a loss of pressure in a natural gas system. The hydraulic/pressure collapse is a result of a serious pipeline incident such as pipeline ruptures, production disruption, or other incident interrupting supply for an extended period. Media or other accounts of incidents often focus on customer outages or the initiating event on the system as opposed to the hydraulic collapse process itself.

2.2 Can you please provide examples of this happening to a major gas distribution system?

Response:

Multiple examples of hydraulic collapse can be found in the responses to BCUC IR1 4.3, 5.2.1 and 10.3.1, CEC IR1 15.4, and RCIA IR1 9.1.

2.3 Can you please explain how, if valves on T-South isolate the ruptured pipe segment, and customer furnace equipment has a safety thermocouple valve that shuts off the gas supply when the flame is extinguished, the oxygen necessary to create a flammable methane gas-to-air mix between the LFL/UFL (Lower and Upper Flammability limits – 4.4% and 16.4%, respectively) would get into a transmission system , such as CTS, which has a normal operating pressure of 2160psi? Our understanding of the physics of such ingress is that the high pressure in an airtight pipe would prohibit such ingress, at least until the point where the in-pipe pressure had reduced to near-atmospheric pressure , and would mix only very slowly after that.

Response:

FEI clarifies that the CTS operates at a maximum operating pressure of 583 psig, and not 2160 psig as suggested by the question.

It is correct that the risk of air ingress occurs when the pipeline pressure drops to zero. Air ingress is unlikely but can occur in the transmission system during a hydraulic collapse, but more commonly occurs in distribution systems. A pressure reduction of this kind begins in the extremities of distribution systems, where pressures are lowest under normal circumstances, and have the potential to progress upstream into the transmission system. However, a hydraulic collapse of downstream distribution systems would slow the pressure loss in the transmission system. Faced with this circumstance, FEI would act to isolate the transmission system from the distribution system, thereby preserving some positive pressure in the transmission system. As a result, the transmission system pressure would likely not drop to zero and the possibility of gas/air mixtures would be avoided.

A distribution system hydraulic collapse is more likely to experience air ingress which drives the need for purging. Slugs of air or gas/air mixtures have sufficient time to enter the system during an extended and widespread distribution system outage through a variety of means including pre-existing above- and below-ground leaks, reported or unreported third party damage, appliances left on or turned on (stoves or ranges) or failed appliance safety valves. This creates a requirement for purging slugs of air or gas/air mixtures from the system. The complex interconnected nature of distribution systems typically makes purging of large collapsed systems a very complex and time consuming process.

2.4 Given the above description of the physical principles governing gas-air mixing in a gas distribution system, how long (approximately) would it take the CTS pipeline system to get the point of “hydraulic collapse”, assuming a rapid isolation of the rupture?

Response:

In the response to MS2S IR1 6i, FEI provided a table showing that following a complete loss of upstream supply during peak demand conditions, if FEI took no further actions, the CTS would collapse from an operating pressure of between approximately 500 to 583 psig down to effectively zero (exhausting all available line pack) in approximately 3.6 hours. As discussed in the response to MS2S IR2 2.3, collapse of downstream distribution systems would occur much sooner, and well-before the pressure of the transmission system drops to zero. In the intervening period, FEI would attempt to preserve some positive pressure in the transmission system by closing system valves (i.e., implement a controlled, albeit widespread, shutdown) to mitigate subsequent purging requirements.

Issue 3: Insurance. None of the documents to date have dealt with the subject of the insurance coverage on the storage tanks, plant and (especially) tankers and barges plying to and from the Fortis-owned jetty on the Fraser. The 64,000-tonne Phase 2 "resiliency" tank is located within metres of an industrial complex that will have many employees working there, at least during daytime hours. LNG barges and tankers will have to navigate past populated areas of South Richmond, North Delta and Steveston, exposing them, and other river users, to temporary, but significant, risk. Specifically, what <u>third-party</u> insurance coverage will be provided for:

3.1 The storage tanks and liquefaction facilities?

<u>Response:</u>

FortisBC Holdings Inc., through the Fortis Group of Companies' insurance program, administered by Fortis Inc., carries property and casualty insurance, including coverage for the existing assets at Tilbury.

3.2 Vessels (barges and tankers visiting the LNG facility)? The coverage would be in addition to regular hull and cargo insurance, and would need to cover third parties other than FEI and TMJ - does it?

<u>Response:</u>

The TLSE Project will replace the Base Plant storage tank and regasification equipment with a new 3 Bcf LNG storage tank and 800 MMcf/day of regasification capacity. The Project does not include barges and tankers visiting the Tilbury LNG facility.

FortisBC Holdings Inc., through the Fortis Group of Companies' insurance program, administered by Fortis Inc., carries property and casualty insurance, including coverage for FEI-owned assets at Tilbury. Through this insurance program, costs specific to assets owned by FEI are allocated to FEI.

3.3 In May, 2014, FEI signed an agreement with the Corporation of Delta (included in FEI's response to BCUC IR#1- P. 326-332) permitting FEI to build on the Tilbury site, despite its location behind a dyke on the flood plain of the Fraser, and less than 1m. above river level. That agreement stipulated that, in exchange for indemnifying Delta from any liability, the municipality would permit FEI to build <u>below</u> the 3.5m. design level of the municipal storm drainage system. Does this agreement nullify any of FEI's third-party liability coverage for accidents, malfunctions and flood events?

Response:

The agreement referenced in the question does not nullify FEI's insurance coverage at Tilbury. The Tilbury assets are fully insured for all risks of physical damage, including flood.

Issue 4: RNG. In our IR#1 question set, we asked the questions below, but would be more satisfied with the fuller detail in some of the answers provided. So we are asking some of those questions again:

Perhaps spurred by the looming climate crisis and the pressure brought to bear on fossil-fuel vendors [4], FEI has declared its "30by30" plan to reduce customer GHG emissions 30% by 2030.

As outlined by FEI on its website, the plan rests on 4 pillars, viz:

1. Greater energy efficiency (in homes, businesses and industry);
2. Increasing RNG (renewable gas- to 15% of its NG supply) ;
3. Global LNG (i.e. exports to trans-oceanic customers)
4. LNG-powered transportation (including bunkering of vessels capable of storing and burning LNG– displacing "dirtier" fuels).

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[4] In the World Scientist Warning of a Climate Emergency 2021, more than 13,800 scientists urge governments to phase-outand ban fossil fuels and shift to renewables; and slash short-lived air pollutants like black carbon, methane, and hydrofluorocarbons.[1]
The latest report from the Intergovernmental Panel on Climate Change warns that immediate reductions in greenhouse gasesincluding carbon dioxide, and especially methane (i.e., natural gas) are needed to avert the worst impacts of climate change.[2]
The International Energy Agency has called on world governments to immediately stop investments in and approvals of newoil and gas projects to limit the global temperature rise to 1.5 °C.[3]
World-wide, methane emissions from fossil fuel extraction is 25-40% higher than previously estimated.[4] A report releasedthis year by the BC OGC shows that fugitive methane emissions in British Columbia are up to 2.2 times higher than previous estimates.[5]

REFERENCES

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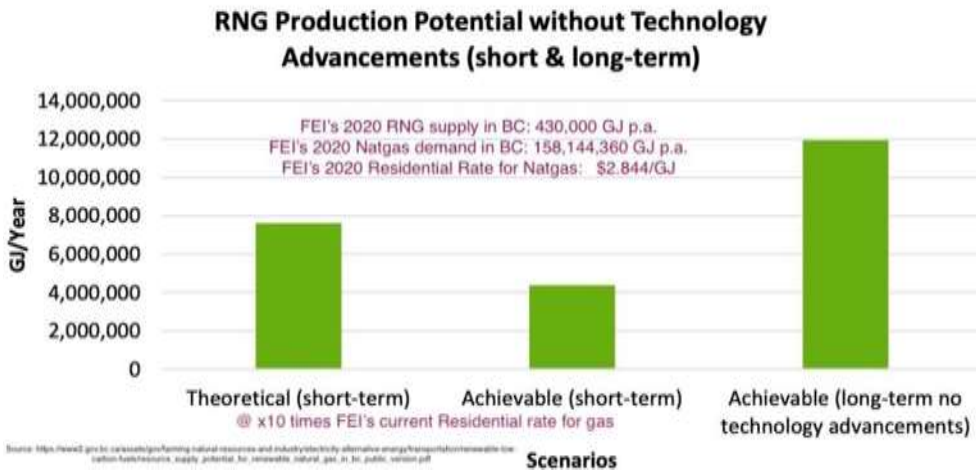
5. Tyner DR & Johnson MR (2021) Where the methane is: insights from novel airbourne LiDAR measurements combined with ground survey data. Environ. Sci. Technol. 2021, 55, 9773−9783. https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c01572

Figure 1: RNG Production Potential without Technology Advancements at $28/GJ



As the BC-Government supplied graph opposite shows, the current supply of RNG is a tiny (0.3%) proportion of FEI's NG supply, and prospects for increasing it to 15% dim, even at prices 10 times that currently charged.

FEI has indicated (in its response to MS2S' IR#1 submission, Q. 20) *that "FEI projects that by the end of 2021 it will have contracts in place for approximately 8,500,000 gigajoules of RNG — roughly 5 percent of FEI's total natural gas supply. Additionally by 2025, FEI projects that it will have contracts in place for approximately 24,000,000 gigajoules of renewable gas— over 10 percent of FEI's total natural gas supply".*

Questions:

4.1 What is the current level of customer emissions from FEI-supplied natural gas (NG)?

Response:

The 2020 FEI-supplied natural gas throughput was 147 PJ. This accounts for approximately 7.4 million tonnes CO2e.

4.2 How much would this figure be reduced if 15% of the gas supply were RNG?

Response:

Under the Greenhouse Gas Reduction Regulation, FEI is enabled to purchase up to 31 PJ of renewable gas (15 percent of non-bypass volumes), which would reduce GHG emissions by approximately 1.6 million tonnes CO2e.

4.3 How much (roughly) of Fortis' 30by30 emissions reduction goal will be achieved with (i) local (i.e. BC) customers, with (ii) LNG bunker fuel customers and (iii) with foreign LNG customers?

Response:

FEI notes that the TLSE Project is a resiliency project.

As described in the response to MS2S IR1 20.iv, the largest opportunity for greenhouse gas emissions reduction in FortisBC's 30BY30 plan will be achieved by delivering renewable gas to FEI's domestic customers, which comprises approximately half of the targeted reduction amount. The next largest source in the 30BY30 plan is LNG for both domestic and international customers, which is expected to make up approximately one quarter of the targeted reduction amount. Energy efficiency, and low and zero carbon transportation options for domestic customers will make up approximately one quarter of the targeted reduction amount.

At this time, FEI expects LNG marine fuelling to play a larger role in its 30BY30 target than international bulk shipments; however, FEI continues to reassess how to achieve this target and has incorporated significant flexibility into its plans. Further, as the energy industry and all levels of government continue to invest in and support new technologies, FEI's plans may require adjustment to incorporate and reflect these technologies.

4.4 Is FEI aware of the recent IMO report[5] citing scientific research casting doubt on the climate benefits claimed for diesel-to-LNG fuel-switching?

Response:

FEI notes that the TLSE Project is a resiliency project.

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[5] This recent IMO paper (the International Maritime Organization regulates world shipping) paper https://www.professionalmariner.com/imo-emissions-report-raises-new-concerns-about-methane-slip/on the emissions from LNG-fuelled marine engines suggests that burning LNG in marine engines actually producesmore GHGs than diesel. This is largely because of the phenomenon of "methane slip" , which is unburned methane escaping the ignition process. Because Methane is 86 times more powerful as a GHG than CO2, the net effect is to make burning LNG in lieu of diesel a poor choice of fuels.
Another recent paper (https://theicct.org/sites/default/files/publications/Climate_implications_LNG_marinefuel_01282020.pdf), finds much the same results. It states that " Using a 20-year GWP, which better reflects the urgency of reducing GHGs to meet the climate goals of the International Maritime Organization (IMO), and factoring in higher upstream emissions for all systems and crankcase emissions for low-pressure systems, there is no climate benefit from using LNG, regardless of the engine technology".

FEI is aware of the IMO report and that the issue of methane slip is being addressed by industry and regulators. For example, two of the largest marine engine manufacturers (MAN Energy Solutions and Wärtsilä) are engaged in aggressive technical measures to minimize and eliminate methane slip in their engines, including an engine technology introduced by MAN Energy that will reduce methane slip up to 90 percent.[6]

Finally, the IMO agenda includes the potential to regulate methane slip which can be included in the suite of measurable indexes to evaluate ships' designed energy efficiency (EEDI) and how efficiently the ships transport goods and passengers during operations (CII).

4.5 Does the delay in completing the North Vancouver Wastewater Treatment plant affect FEI's plans for acquiring RNG supply? (FEI's website currently warns that "*Subscriptions for RNG have been delayed until new supply can be brought online*").

Response:

The delay in completing the North Vancouver Wastewater Treatment plant does not affect FEI's RNG supply or its 30BY30 target as FEI did not anticipate acquiring RNG from this source, nor has it included RNG from this plant in any of its future RNG forecasts.

FEI has achieved significant growth in Renewable Gas supply and reopened the RNG Program to new subscriptions in October 2021.

4.6 Does the delay in completing the North Shore Wastewater Treatment plant affect FEI's 30by30 goal, and its plan to have 24,000,000 GJ of RNG supply (10% of total gas supply) available by 2025?

Response:

Please refer to the response to MS2S IR2 4.5.

6 https://people.man-es.com/docs/librariesprovider51/default-document-library/technical-paper.pdf?sfvrsn=1f9ed3a2_4.

4.7 What short and long-term "technology advancements", referenced in the BC Government report cited above, does FEI think are vital to achieving the 15% RNG target.

Response:

While FEI did not author this report, it interprets "technology advancements" as relating to two areas which will help to achieve the above-referenced percent RNG target. First, improvements to the efficiency and to lower the cost for biogas upgrading equipment, as well as improved digestate management processes, will enable additional RNG production. Second, the report refers to for the potential development of wood to RNG conversion technology, thereby reducing the cost and increasing the scalability of RNG production.

Moreover, the above chart does not appear to account for the potential RNG supply from the forestry sector. In particular, FEI is enabled through the Greenhouse Gas Reduction Regulation (GGRR) to acquire renewable gases in the form of biomethane, synthesis gas and lignin to displace natural gas consumption. Developing supply from this potentially significant source is an area of increased focus for both FEI and the BC provincial government.

In addition to the RNG supplies depicted above, renewable and low-carbon hydrogen are also important sources of renewable gas supply. The BC Hydrogen Strategy, published by the BC provincial government, outlines its ambition to accelerate the production and use of renewable and low-carbon hydrogen. FEI is working with partners across the province to bring supply to BC's energy system.

When taken together, the potential supply volumes for renewable gas in FEI's system are sizeable and will be a significant component of FEI's decarbonization strategy to 2050.