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March 20, 2025

Residential Consumer Intervener Association
1130 W Pender Street
Vancouver, B.C V6E 4A4

Attention: Samuel Mason, Consultant

Dear Samuel Mason:

**Re: FortisBC Energy Inc. (FEI)**

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

**Response to the Residential Consumer Intervener Association (RCIA) Information Request (IR) No. 5**

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On December 29, 2020, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with regulatory timetable established in British Columbia Utilities Commission Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to RCIA IR No. 5.

FEI has filed the response to RCIA IR5 67.2 on a confidential basis as identified in that response and has redacted the response for the public record of this proceeding. FEI requests that the unredacted portion of this response only be accessible to the BCUC, consistent with BCUC Order G-19-25 and for the reasons discussed in the response.

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

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

**63. Reference: Exhibit B-60 Supplemental Evidence p.13**

**Tilbury Base Plant**

On page 13 of the Supplemental Evidence, FEI states:

> *The Base Plant houses the only regasification equipment at Tilbury. It is obsolete and is experiencing increasing rates of failure and reliability issues, which have rendered the facility unavailable when called upon.*

63.1 Please provide specific details of the times when the Base Plant was unavailable when called upon, including the number of instances in each of the past three years.

**Response:**

Please refer to the table below. As this response is also addressing MS2S IR5 5.3, FEI provides the timing and frequency of Tilbury Base Plant malfunctions since 2019 in the table below. FEI does not keep records regarding the duration of malfunctions (i.e., when each malfunction began and when each was resolved). To date, and despite these malfunctions, FEI has been able to get sendout from the Base Plant; however, there have been multiple instances where sendout was delayed by up to 12 hours when called upon. Delays can also have potentially significant implications for FEI's ability to meet firm demand, as FEI is typically calling on on-system LNG in circumstances where other supply resources in the ACP are already engaged.

| Date | Asset Type Failure | Testing or Request for Sendout | Description of Malfunction |
|---|---|---|---|
| 2/26/2019 | Valve | Inspection and troubleshooting | Valve leaked on Pump "D". |
| 3/7/2019 | Valve | Inspection and troubleshooting | Packing leak on multiple valves. |
| 7/12/2021 | Valve | Request for sendout | Vaporizer "C" 3" ball valve seizure, closed caustic soda batch feed. |
| 11/13/2021 | Piping | Inspection and troubleshooting | Upstream flange on Pump "A" discharge 4" line was passing. |
| 11/13/2021 | Valve | Inspection and troubleshooting | Bypass discharge valve packing on Pump "B" was passing, set off the LEL alarms, and mustered the plant. |
| 11/13/2021 | Valve | Inspection and troubleshooting | Water fill line isolation valve for vaporizer baths was not closing and had to be replaced. |
| 12/22/2021 | Sendout Pump | Request for sendout | Pump "A" seized. |
| 12/28/2021 | Odorization unit | Request for sendout | Mercaptan leak detected. |
| 12/28/2021 | Vaporizer | Request for sendout | Soda ash container was plugged. |
| 12/28/2021 | Vaporizer | Request for sendout | Vaporizer bath water line piping split due to freezing. |
| 12/28/2021 | Sendout Pump | Request for sendout | Pump "A" seal oil leak detected. |

| Date | Asset Type Failure | Testing or Request for Sendout | Description of Malfunction |
| --- | --- | --- | --- |
| 12/28/2021 | Valve | Request for sendout | Vaporizer "D" inlet valve packing leak detected and fixed. |
| 12/30/2021 | Sendout Pump | Request for sendout | Low amp trips on LNG Pump "A" during startup. |
| 12/31/2021 | Vaporizer | Request for sendout | Frozen vaporizer water circulation line. |
| 2/22/2022 | Instrumentation | Request for sendout | Challenge to cool down, had to manually control the vaporizer outlet via flow controller FIC 911D to maintain operation. |
| 12/8/2022 | Power blink - no failure | Request for sendout | Power outage at 7:30am, lost vaporizers and pumps, then restarted. |
| 12/19/2022 | Sendout Pump | Request for sendout | Two starts on Pump "C". Waited 1 hour between starts. |
| 12/19/2022 | PSV | Request for sendout | Pressure relief valve SV-L912-1 frosted up, switched to relief valve SVL912-2. Delay while switching. |
| 12/20/2022 | Vaporizer overload | Request for sendout | Maxed at 3.1 MMSCFH. Sendout tripped, lost pumps and vaporizers, unable to maintain outlet temp, shutdown on low outlet temp. |
| 12/22/2022 | Sendout Pump | Request for sendout | Pump "A" motor failed during pump operation, leading to a fire after catastrophic failure. After being taken out of service for remainder of season, repaired motor was reinstalled. |
| 12/22/2022 | Valve | Request for sendout | Vaporizer "D" recirculation pump check valve failed due to flapper falling off. Flapper was found in strainer and re-installed. |
| 12/22/2022 | Instrumentation | Request for sendout | Vaporizer "C" blocked in at inlet due to suspected passing control valve on inlet. |
| 1/31/2023 | Valve | Request for sendout | Vaporizer inlet control valve stem was leaking LNG, Fire and Gas alarm triggered on rundown line, made safe and repaired. |
| 2/25/2023 | Vaporizer | Request for sendout | Vaporizer "D" blower: Drive side oiler level was low and oil was leaking around shaft area. |
| 4/20/2023 | Valve | Request for sendout | Pump discharge recycle control valve PC-911 malfunctioning. Maintenance recalibrated. |
| 4/20/2023 | Valve | Request for sendout | Gate valve downstream of control valve PC-911 has a packing leak. After shut down and leak repair, sendout continued. |
| 5/2/2023 | Valve | Testing of sendout | Pump discharge recycle control valve controller set point not matching the control valve position in the field. Controller PIC-911 calibrated. |

| Date | Asset Type Failure | Testing or Request for Sendout | Description of Malfunction |
|---|---|---|---|
| 5/2/2023 | Valve | Testing of sendout | Sendout delayed due to a leaking valve packing in pumphouse. |
| 6/27/2023 | Sendout Pump | Sendout offline | Pump "D": Pump "D" has not been available for sendout due to high discharge pressure for years. It cannot run in parallel with pumps A, B or C. Pump was removed, de-staged and impellers trimmed. Pump will be re-installed in 2025. |
| 8/1/2023 | Sendout Pump | Sendout offline | Pump "B" seal failure. Following the seal repair the pump had a high motor bearing temperature. |
| 8/30/2023 | Sendout Pump | Inspection and troubleshooting | Pump "C": Significant oil loss and suspected leaking oil into the pump can. |
| 9/18/2023 | Sendout Pump | Inspection and troubleshooting | Pump "B": Reported sharp, high pitched rubbing noise when spinning the motor. Motor removed and repaired. |
| 10/20/2023 | Sendout Pump | Testing of sendout | Pump "A" oil leak from the shaft deflector. Pump able to run for the duration of potential sendout events. |
| 10/31/2023 | Sendout Pump | Testing of sendout | Lost Pumps "A" and "B" on low amp trip. |
| 10/31/2023 | Valve | Inspection and troubleshooting | Leak of valve packing and PSV. |
| 11/1/2023 | Sendout Pump | Testing of sendout | Pump "C" seized on cool down due to faulty temperature probe. Pump was warmed up then cooled down again and it became unseized. |
| 11/4/2023 | Sendout Pump | Testing of sendout | Motor of Pump "B": During sendout testing, upper motor bearing temperature increased significantly. Unit was shutdown and motor was found to be seized. |
| 12/20/2023 | Vaporizers | Testing of sendout | Leak on Vaporizer "C" flow transmitter FC911C. |
| 12/20/2023 | Instrumentation | Inspection and troubleshooting | Flow transmitter leakage. |
| 10/3/2024 | Vaporizers | Testing of sendout | Vaporizers "A"/"B"/"C"/"D": Due to frequent failures of igniters to ignite the burners during past sendout tests, new ignitors were installed on all three burners. |

| Date | Asset Type Failure | Testing or Request for Sendout | Description of Malfunction |
|---|---|---|---|
| 10/6/2024 | Sendout Pump | Both test and request | Pumps “A”/“B”/“C” trip on low-amp a few minutes after starting the pump. This has been an ongoing issue and Operations has managed it to a large extent by improving the send out procedure. However, it has not been resolved completely. |
| 11/1/2024 | Vaporizers | Sendout offline | Vaporizer “C”: Due to severe internal corrosion, vaporizer bath drain started leaking water. Bath repair and painting was completed in September 2024. During this time, vaporizer was not fully available. |

63.2 Please explain how FEI met the demand for gas when the Base Plant was unavailable and what the cost implications were.

**Response:**

Please refer to the response to RCIA IR5 63.1.

**64. Reference: Exhibit B-60 Supplemental Evidence p.41**

**Impact of AMI on Outage Duration**

On page 41 of the Supplemental Evidence, FEI provides Table 3-1 and states:

*As discussed below, at average winter temperatures of +4°C, between 600,000 and 640,000 customers will lose service on Day 1 of a T-South no-flow event, with the number in that range depending on the location of the disruption on T-South. With this number of customer outages, and assuming FEI's Advanced Metering Infrastructure (AMI) is in place, it will take FEI between 8 and 10 weeks to restore service. The number of customers losing service on Day 1 will be higher than the numbers noted above in below-average winter temperatures, which (all else equal) has the effect of further extending customer service restoration time.*

**Table 3-1: Quantitative Metrics Related to Severity of a T-South No-Flow Event at Average Winter Temperatures by Incident Location**

| Type of Impact | Quantitative Metric | AV-1 Value | AV-2 Value | AV-3 Value | AV-54 Value |
|---|---|---|---|---|---|
| Direct customer service impact | Number of firm customers losing service on Day 1 | 640,100 | 600,400 | 640,400 | 600,400 |
| Direct customer service impact | Total Outage Duration[70] | 63.3 days | 60.2 days | 71.9 days | 66.3 days |
| Direct customer service impact | Total firm customer-outage-days | 24 million | 21 million | 32 million | 28 million |

In its response to BCUC IR1 16.2, FEI states:

*FEI is assessing the feasibility of using AMI to provide customers the additional option of a remote reconnect. If feasible, the remote reconnect option could involve asking customers pre-screening questions (over the phone) to confirm they are capable of safely relighting their appliance(s). If the customer wants to relight their appliance(s) and demonstrates the necessary knowledge, FEI would send a command, via the AMI network, for the meter to perform a remote dial test to confirm the integrity of the customer's house piping and appliance(s). If the meter passes its remote dial test, the customer would be informed that the appliances would be ready to be relit*.

64.1 Please provide an update on FEI's assessment of the feasibility of using AMI to assist with remote reconnections of customers.

**Response:**

FEI is currently deploying its AMI project across its service territory. Following completion of the project, and in consideration of the new capabilities of the AMI meters, FEI will be determining whether any changes to its operations should be made. In particular, FEI has not yet determined the feasibility of the remote reconnect capability in its normal operations, but as previously discussed in the response to BCUC IR3 112.1, relighting a gas appliance can be intimidating for many customers. As such, FEI does not expect that the remote reconnection capability provided by the AMI project will significantly increase the number of customers willing to conduct their own relight(s). FEI's assumption of 25 percent of customers performing their own relights therefore remains appropriate.

64.2 Please confirm whether FEI has developed plans for remote relights, including estimates of the number of customers who would conduct their own relights. If confirmed, please provide details. If not confirmed, please explain why FEI has not developed plans.

**Response:**

Please refer to the response to RCIA IR5 64.1.

On page 51 of the Supplemental Evidence, FEI states:

*Most of the restoration time is spent manually relighting customer appliances. FEI's Rebuttal Evidence, and the two timelines shown in this section (Figures 3-7 and 3-8), reflect a number of favourable assumptions that (other things being equal) may tend to understate the total restoration duration. For example, it contemplates only relighting essential appliances within a premises to save time and assumes that 25 percent of customers relight their own appliances.*

64.3 Please explain how FEI determined that 25 percent of customer relighting their own appliances is an appropriate estimate.

**Response:**

Please refer to the response to BCUC IR3 112.1 for an explanation of how FEI determined 25 percent is an appropriate estimate.

64.4 Please explain whether the ability to remotely relight and reconnect customers alters FEI's assumption of 25% of customers performing their own relights.

**Response:**

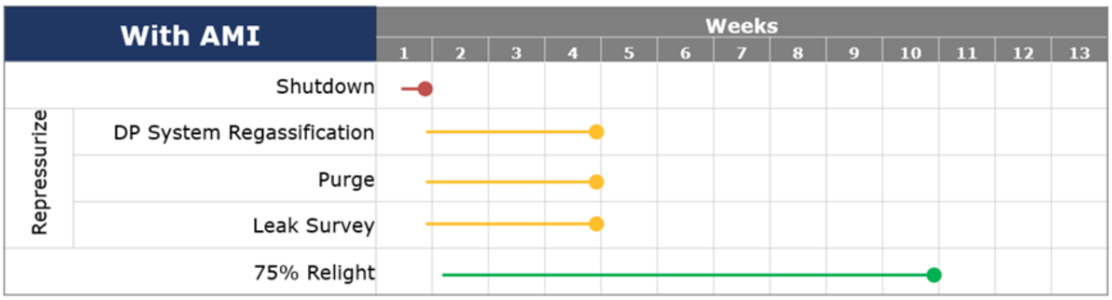
Please refer to the response to RCIA IR5 64.1.

**65. Reference: Exhibit B-60 Supplemental Evidence p.51**

**Purge, Leak Survey, and Relight**

On page 51 of the Supplemental Evidence, FEI provides Figure 3-8 showing the restoration timeline:

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




65.1 Please confirm whether the leak survey timeline shown in Figure 3-8 is based on FEI using mobile leak detection technology. Mobile leak detection allows vehicle-mounted leak detection instruments to perform leak surveys while the vehicle travels at posted speed limits. If not confirmed, please estimate the reduction in leak survey time from implementing such technology.

**Response:**

FEI assumed that field crews would use FEI's existing capabilities for leak surveying the Distribution Pressure (DP) system, which consists of handheld portable leak detection devices (e.g., flame ionization) and walking the system. FEI did not attribute a material amount of time to conducting leak surveys during the re-pressurization process; thus, the implementation of mobile leak survey technology would not have a material impact on shortening FEI's timeline to re-pressurize a collapsed Lower Mainland system. This is demonstrated in the Figure 3-8 timeline by observing that the regasification, purge, and leak survey activities all occur in parallel with one another.

With respect to the time that the leak survey contributes to the full resumption of service to the Lower Mainland, FEI stated the following in the Rebuttal Evidence to RCIA:[1]

> FEI is, in fact, anticipating that most areas of the system—where the segment is holding its pressure as gas is reintroduced (which FEI refers to as a pressure check)—a leak survey would occur at the same time FEI is relighting appliances in that area. Leak surveys and purging conducted in the manner FEI is anticipating reduces risk of harm and contribute relatively little to the overall timeline for full resumption of service to the Lower Mainland.

[1] Exhibit B-46-1, FEI Rebuttal Evidence to RCIA, p. 4.

**66. Reference: Exhibit B-61 Resiliency Plan p.30**

**Assumptions Made in the Baseline Scenario**

On page 30 of the Resiliency Plan, FEI states:

> *The following summarizes FEI's assumptions regarding controlled and uncontrolled shutdowns. All assumptions include gas AMI being in place, and are based on the event occurring under average winter conditions.*
>
> *For the baseline scenario, which is the status quo scenario where it is assumed that there is no available LNG volume at Tilbury to provide mitigation, the following assumptions were made:*

The assumptions made in the Baseline scenario are redacted.

66.1 Please summarize (and if necessary anonymize) the assumptions made in the Baseline scenario such that they can be publicly disclosed.

**Response:**

FEI summarizes the assumptions made in the Baseline Scenario below. FEI has revised the description of the assumptions such that they can be made public.

1. Other than for the exceptions listed below, all on-system AVs result in an uncontrolled shutdown. This is based on the assumption that, under average winter conditions, FEI's on-system line-pack would not provide enough time to implement a controlled shutdown. The exceptions to this assumption are as follows:
   a. Certain asset types where free-flow around the asset remains possible (e.g., the asset has failed; however, a normally closed mainline pipeline valve, which allows the asset to be bypassed, can be opened to bypass the asset).
   b. On-system AVs where the result of the asset failure only impacts a non-T-South source of supply to the Lower Mainland. That is, the result of the asset failure is a partial supply disruption to the Lower Mainland.
   c. Due to a finite alternative supply source, on-system AVs which impact Vancouver Island result in a controlled shutdown.
2. Under average winter conditions, due to the assumed line-pack and an additional supply source, failures north of a certain location on T-South are assumed to be controlled.
3. Under average winter conditions, due to the assumed line-pack and no additional supply sources, failures south of a certain location on T-South are assumed to be uncontrolled.
4. Off-system failures in FEI's Columbia region are assumed to result in a controlled shutdown.

**67. Reference: Exhibit B-60 pp.92,133**

**Mist Storage Expansion**

On page 133 of the Supplemental Evidence, FEI states:

> *Once the Base Plant ceases to operate in the baseline scenario (i.e., Supplemental Alternative 1), firm customers would face curtailments in normal operations absent the completion of a regional infrastructure upgrade that is sufficiently large to replace the lost peaking supply from Tilbury. FEI believes there is no possibility of this occurring by 2030… FEI is also not aware of any other potential for regional market area storage upgrades, other than the North Mist Expansion Project which is anticipated to complete in 2029. Any subsequent expansion at Mist, if possible, would take multiple years to develop post 2029*.

On page 92 of the Supplemental Evidence, FEI states:

> *FEI filed an application with the BCUC in respect of underwriting an expansion of the Mist facility to restore those amounts, which was recently approved. The effect of that expansion is shown in the yellow bars in Figure 3-25).*

The Mist expansion appears to add approximately 65,000 Dth/day of deliverability.

67.1 Please provide the total capacity of the Mist storage expansion that would be allocated to FEI and the timeline for when this capacity would be available to FEI.

**<u>Response:</u>**

Please refer to the response to BCUC IR5 131.1.

67.2 Please confirm whether FEI will have renewal rights to the additional Mist storage from the expansion.

**<u>Response:</u>**

FEI is requesting that this response be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents, as set out in Order G-296-24. FEI requests that the BCUC exercise its discretion under Section 6 of the BCUC's Rules of Natural Gas Energy Supply Contracts and allow this information to remain confidential due to its commercially sensitive nature, as it is a term of the agreement between FEI and the counterparty. Consistent with Order G-19-25, the information is Restricted Confidential Information and FEI requests that the information only be accessible to the BCUC.

[redacted]

67.3 Please confirm or otherwise explain whether FEI could have increased (or still can increase) the capacity in (a) by an additional 0.6 or 1.0 BCF, and increased the deliverability by an additional 150 mmscf/d or 200 mmscf/d.

67.3.1 If confirmed, please further confirm or otherwise explain whether FEI could fill the additional 0.6 BCF with interruptible pipeline transportation on the Williams pipeline or with other sources of supply from the United States.

67.3.2 If confirmed, please further confirm or otherwise explain whether FEI could secure backhaul pipeline transportation from Mist to Huntingdon/Sumas.

67.3.3 If confirmed, please estimate the annual cost of the additional 0.6 (or 1.0) BCF capacity and 150 (or 200) mmscf/d deliverability.

**Response:**

Not confirmed. Please also refer to the response to BCUC IR5 131.1 for more details.

**68. Reference: Exhibit B-60 p.139**

**Additional Storage to Displace Annual Contracting Costs**

On page 139 of the Supplemental Evidence, FEI provides Table 4-11:

**Table 4-11: Avoided Annual Gas Supply Costs for Supplemental Alternatives 4, 4A, 8, and 9 ($ millions)**

| Supplemental Alternatives | Description | Annual Gas Supply Costs ($millions) Present to 2030 | 2030 to 2035 | 2035 onwards | Incremental to Baseline / (Avoided Costs) ($ millions) Present to 2030 | 2030 to 2035 | 2035 onwards |
|---|---|---|---|---|---|---|---|
| 1 | No Capital Upgrades (Continue to rely on existing Base Plant until it fails. No on-system peaking gas supply thereafter and no resiliency reserve) | 7.0 | 7.0 | 63.0 | | | |
| 4 | Like-for-Like Replacement for 0.6 Bcf and 150 MMcf/d (No Resiliency Reserve) | 7.0 | 7.0 | 17.0 | - | - | (46.0) |
| 4A | New 1 Bcf Tank and 400 MMcf/d Regasification (No resiliency reserve) | 7.0 | - | - | - | (7.0) | (63.0) |
| 8 | New 2 Bcf Tank and 800 MMcf/d Regasification (1.4 Bcf resiliency reserve and 0.6 Bcf for peaking gas supply) | 7.0 | 7.0 | 17.0 | - | - | (46.0) |
| 9 | New 3 Bcf Tank and 800 MMcf/d Regasification (2 Bcf resiliency reserve and 1 Bcf for peaking gas supply) | 7.0 | - | - | - | (7.0) | (63.0) |

68.1 Please explain and quantify whether there is an opportunity to reduce FEI's annual gas supply costs beyond those shown in Table 4-11 if Alternative 9 is modified to designate a 1.4 BCF resiliency reserve and 1.6 BCF is used for peaking gas supply, displacing a portion of FEI's existing pipeline and storage contracted capacities.

**Response:**

Supplemental Alternative 9 includes the optimal allocation to gas supply based on FEI's current load profile. Therefore, at this time, it would not be cost-effective to size the TLSE tank based on an objective of increasing the amount of peaking supply available beyond 1.0 Bcf so as to displace more of FEI's existing pipeline and market area storage. The tank should be sized to provide the optimal amount of gas supply (1.0 Bcf), plus the optimal amount of resiliency (2.0 Bcf).

Allocating 1.6 Bcf of the Tilbury tank to gas supply could create an imbalance in FEI's gas supply portfolio, given the current load duration curve. This is because an effective gas supply portfolio consists of pipeline, storage and LNG peaking in proportions to match the load duration curve as follows:

- Pipeline is used all year round to provide base load supply.
- Storage is used to provide additional seasonal supply when demand is higher than the pipeline capacity.
- LNG peaking is used to provide shorter duration supply when demand increases significantly when extreme winter events occur.

FEI has historically used LNG less frequently compared to market area storage (which it uses for daily balancing in addition to providing additional seasonal supply).

Re-allocating the resiliency reserve proportion of the TLSE tank could occur in the future if peak load were to decline on FEI's system (as shown in the hypothetical adverse scenarios provided in Section 4.5.5 of the Supplemental Evidence). While additional LNG peaking supply would provide additional flexibility for portfolio optimization in the ACP, there is no information to suggest significant changes to the tank's allocation would be required at this time.

For the reasons above, FEI respectfully declines to provide the requested quantification of gas supply costs. Such an analysis would require running the portfolio optimization with a hypothetical load duration curve to assess the impact of 1.6 Bcf LNG on the supply portfolio. FEI develops its ACP portfolio on an annual basis and informs the BCUC of the changes needed to contract market area resources. As such, if additional LNG peaking supply becomes cost-effective due to significant changes from the current load profile, it will be identified through the ACP.

**69. Reference: Exhibit B-60 pp.198-199; Appendix K Schedule 10**

**Rate Impacts**

On page 198 of the Supplemental Evidence, FEI states:

> *The levelized total rate impact of the Preferred Alternative over the 67-year analysis period, including both the delivery rate impact and the cost of gas savings, is 2.45 percent, which is equivalent to $0.228 per GJ.*

Table 6-4 on page 199 shows the cumulative and levelized rate impacts:

| | | | |
|---|---|---|---|
| 14 | Delivery Rate Impact in 2035 (%) | 10.40% | Schedule 10; Line 25 (2035) |
| 15 | Total Rate Impact (incl. Cost of Gas) in 2035 (%) | 2.97% | Schedule 10; Line 35 (2035) |
| 16 | | | |
| **17** | ***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)*** | **2.45%** | **Schedule 10; Line 39** |
| **18** | ***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)*** | **0.228** | **Schedule 10; Line 46** |

Table 4-9 on page 130 shows the levelized rate impacts of four alternatives:

| | Alt 4 - 0.6 BCF 150 MMcf/d (No resl) | Alt 4A - 1 BCF 400 MMcf/d (No resl) | Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl) | Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl) |
|---|---|---|---|---|
| Total Capital Costs during Construction, As-Spent $ ($000s) | 826,921 | 893,199 | 1,030,287 | 1,140,962 |
| | | | | |
| PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years | 790,047 | 892,612 | 1,133,983 | 1,240,821 |
| PV of Gas Supply Cost/Savings ($000s) over 67 years | (366,362) | (517,554) | (366,362) | (517,554) |
| **Total PV of Cost of Service over 67 years ($000s)** | **423,685** | **375,059** | **767,621** | **723,267** |
| | | | | |
| Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%) | 1.44% | 1.27% | 2.60% | 2.45% |
| Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ) | 0.134 | 0.118 | 0.242 | 0.228 |

Confidential Appendix K Schedule 10 shows the cumulative rate impacts.

69.1 Please provide a non-confidential table or tables showing the cumulative delivery and total rate impacts for each year (i.e. lines 25 and 35 of Schedule 10) from 2026 to 2035 for Alternatives 4, 4A, 8, and 9.

**<u>Response:</u>**

Please see Table 1 below for the cumulative delivery rate increase and cumulative total rate impact (including cost of gas), when compared to 2024 Approved rates from 2026 to 2035 for Supplemental Alternatives 4, 4A, 8, and 9.

**Table 1: Cumulative Delivery Rate Increase (%) and Cumulative Total Rate Impact (incl. Cost of Gas) from 2026 to 2035 for Supplemental Alternatives 4, 4A, 8, and 9[2]**

| Particulars | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Cumulative % Delivery Rate Increase (Compared to 2024 Approved)** | | | | | | | | | | |
| Alt 4 - 0.6 BCF 150 MMcf/d (No resl) | 0.12% | 0.19% | 0.76% | 0.16% | 2.39% | 7.58% | 6.95% | 7.00% | 6.98% | 6.96% |
| Alt 4A - 1 BCF 400 MMcf/d (No resl) | 0.12% | 0.19% | 0.91% | 0.12% | 2.70% | 8.40% | 7.73% | 7.78% | 7.77% | 7.75% |
| Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl) | 0.12% | 0.12% | 0.96% | 2.69% | 4.58% | 9.94% | 9.34% | 9.42% | 9.42% | 9.42% |
| Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl) | 0.12% | 0.13% | 1.21% | 2.92% | 4.80% | 11.03% | 10.32% | 10.40% | 10.40% | 10.40% |
| **Cumulative % Total Rate Impact, incl. Cost of Gas (Compared to 2024 Approved)** | | | | | | | | | | |
| Alt 4 - 0.6 BCF 150 MMcf/d (No resl) | 0.07% | 0.11% | 0.47% | 0.10% | 1.46% | 4.62% | 4.23% | 4.26% | 4.25% | 1.78% |
| Alt 4A - 1 BCF 400 MMcf/d (No resl) | 0.07% | 0.11% | 0.55% | 0.08% | 1.65% | 4.70% | 4.29% | 4.32% | 4.31% | 1.36% |
| Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl) | 0.07% | 0.08% | 0.58% | 1.64% | 2.79% | 6.06% | 5.69% | 5.74% | 5.74% | 3.28% |
| Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl) | 0.07% | 0.08% | 0.74% | 1.78% | 2.93% | 6.30% | 5.87% | 5.92% | 5.92% | 2.97% |

*<u>Notes to the table:</u>*

- All four Supplemental Alternatives (4, 4A, 8, and 9) will see the highest delivery rate impact in 2031 as that is the year when all assets are included in FEI's rate base.
- All four Supplemental Alternatives (4, 4A, 8, and 9) will see a decrease in the delivery rate impact in 2032 because that is the year when the full year benefit of the capital cost allowance (CCA) will occur.
- All four Supplemental Alternatives (4, 4A, 8, and 9) will see an increase in the delivery rate impact in 2033 primarily because of the increase in the 1 percent in Lieu of General Municipal Tax under Property Tax. Pursuant to Section 644 of the *Local Government Act*, the 1 percent in Lieu is calculated based on the revenue in the second preceding year of the utility.[3] Given the second preceding year of 2033 is 2031, which is the year with the highest increase in revenue requirement when all assets related to the TLSE Project enter rate base, a higher increase in the 1 percent in Lieu of General Municipal Tax will occur in 2033, resulting in an overall increase in the delivery rate impact.
- For Alternatives 4 and 4A, the delivery rate impact will begin to decline slowly in 2034, while Alternatives 8 and 9 will begin to see the decline in 2035 (although the delivery rate impact in Table 1 above appears to have no change for Alternatives 8 and 9 in 2035 after rounding to two decimal places). This decline is expected as the cost of service will tend to reduce over time as the associated assets continue to depreciate (i.e., earned return will decrease over time as the assets associated with the TLSE Project continue to depreciate). The small difference of 1 year for the beginning of the decline between Alternatives 4/4A and Alternatives 8/9 is due to the higher decrease of CCA deduction for income tax purposes (resulting in a higher increase in income tax) for Alternatives 8 and 9, which is mainly due to the higher capital costs of Alternatives 8 and 9.
- All four Supplemental Alternatives (4, 4A, 8, and 9) will see a large decrease in total rate impact (including cost of gas) in 2035 due to the increase in avoided gas supply costs

[2] The cumulative delivery rate increases and cumulative total rate impacts from 2026 to 2035 reflect the correct calculation for the annual gas costs up to 2035 due to a small rounding error. Please refer to the response to BCUC IR5 131.3.

[3] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/r15001_16#section644

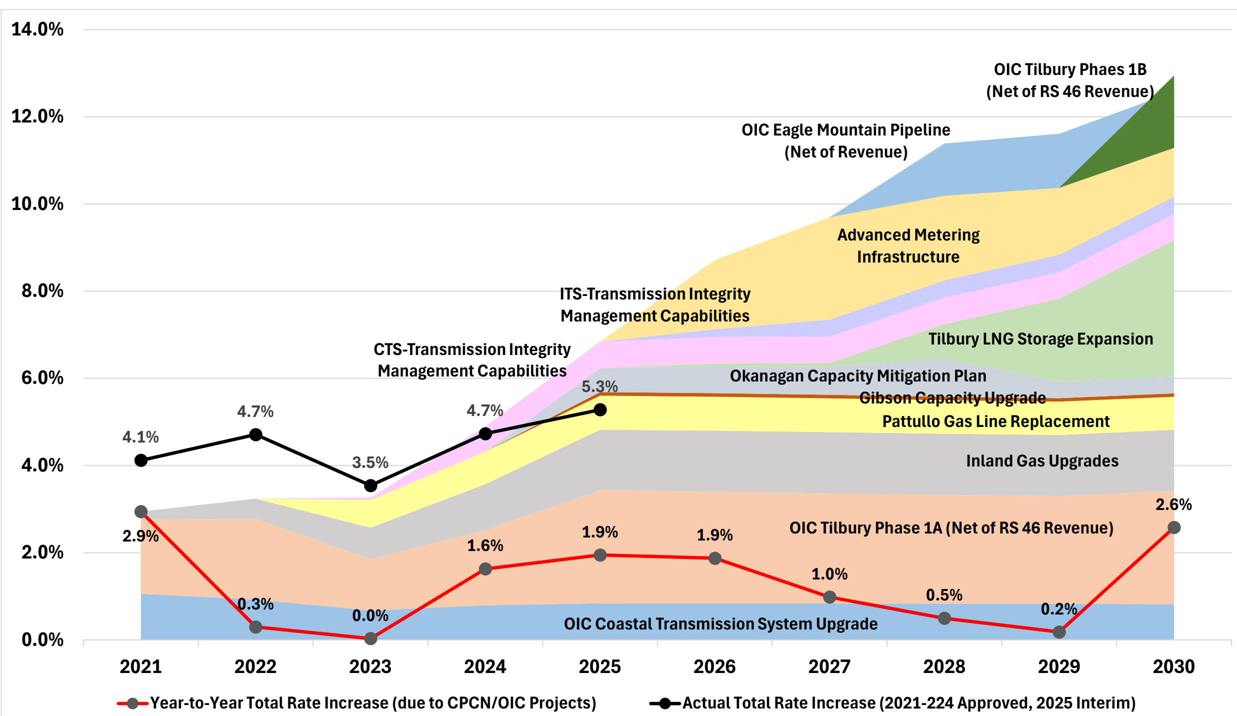
when regional infrastructure is assumed to be upgraded for the purpose of the financial analysis. Please refer to page 134 of the Supplemental Evidence.

69.2 Please provide an update of the graph on page 5 of Exhibit B-4 in the CTS TIMC proceeding showing the forecasted rate impacts for each of FEI's current and proposed CPCN and OIC projects. Please also show the actual delivery rate increases to date.

**Response:**

Please refer to Figure 1 below for an updated cumulative and year-over-year total rate increase for FEI's current and proposed CPCN and OIC projects from 2021 to 2030. FEI also included the actual total rate increase to date from 2021 to 2024 Approved and 2025 Interim. FEI notes that the figure on page 5 of Exhibit B-4 of the CTS TIMC proceeding, dated May 13, 2021, provided the <u>total rate increase</u> due to CPCN and OIC projects, not the delivery rate increase. For consistency, the numbers in percentage shown in Figure 1 below are also based on the total rate increase.

**Figure 1: Cumulative Rate Impact of FEI's Current and Proposed CPCN and OIC Projects**




As shown in Figure 1 above, the cumulative total rate impact from 2021 to 2030 due to FEI's current and proposed CPCN and OIC projects is approximately 12.9 percent, which is equivalent to an average of 1.3 percent over the 10-year period. FEI notes that the primary differences between the updated cumulative total rate increase shown in Figure 1 above and the increases provided in the 2021 CTS TIMC proceeding are due to:

- The delay of the proposed TLSE Project with all assets now estimated to be included in FEI's rate base in 2031;
- The delayed start of the approved AMI project to 2025;
- The removal of the rate impact due to the Okanagan Capacity Upgrade (OCU) project and the inclusion instead of the approved Okanagan Capacity Mitigation Project (OCMP);
- Inclusion of new projects:
  - Approved ITS TIMC CPCN Project
  - Approved Gibson Capacity Upgrade (GCU) Project
  - OIC Approved Eagle Mountain Pipeline (EGP) Project
  - OIC Approved Tilbury Phase 1B Project
- For the OIC Approved Tilbury Phase 1A, Tilbury Phase 1B, and the EGP projects, a forecast of offsetting revenues is included.

Finally, FEI notes that the total rate impacts due to the current CPCN and OIC projects shown in Figure 1 above are for illustration only and do not represent FEI's estimated rate changes for 2025 to 2030. The actual rate changes for FEI will not be dependent on these projects alone as there are various factors such as the demand forecast, taxes, O&M expenses, and other capital additions (i.e., regular capital) that will also affect FEI's revenue requirement and rate changes.

**70. Reference: Exhibit B-60 p.123**

**Load Duration Support**

Figure 4-4 on page 123 of the Supplemental Evidence shows the load duration support for various alternatives at various temperatures.

70.1 Please provide a version of Figure 4-4 that assumes FEI decides to enact a controlled shutdown 8 hours after the incident. In doing so, FEI engages the remote disconnect feature of its AMI meters and proceeds to manually disconnect other loads according to its System Preservation Plan.

**Response:**

FEI notes that deciding to use AMI to pre-emptively shut-in the vast majority of FEI's Lower Mainland customers just 8 hours after the no-flow incident does not reflect a realistic scenario. This is because, to avoid the situation where FEI unnecessarily shuts-in these customers, FEI must be confident that doing so is the optimal decision. Receiving the full information required to make such a decision would likely take more than 8 hours. Further, a staged shutdown is a more likely scenario than shutting in all remote disconnect AMI meters at once. Please refer to Section 4.7.2.3 of the Supplemental Evidence for further discussion on staged shutdowns.

The premise of the question would require FEI to disconnect loads (first through AMI for meters with the remote disconnect module, then manually for the remaining meters) which, for certain Supplemental Alternatives, would result in load being off FEI's system but stored LNG remaining in the TLSE tank. This result does not align with the purpose of Figure 4-4, which shows the load durations for various Supplemental Alternatives under different temperature conditions. In particular, except for cases where there is a regasification constraint (i.e., Supplemental Alternatives 4 and 4A), the durations are based on fully depleting the available stored LNG for the given Supplemental Alternative, rather than some LNG remaining in the TLSE tank as would occur in the scenario proposed by RCIA.

However, in order to be responsive, FEI has provided results from its transient modelling tool based on the modelling assumptions listed below. The output from the modelling shows if a controlled shutdown is possible.

***Modelling Assumptions:***

- 8 hours after the rupture, FEI engages the remote disconnect feature of its AMI meters in the Lower Mainland.
- FEI manually disconnects the remaining Lower Mainland customers at a rate of 12,257 customers per day. These customers come off the system at 8 AM each day, starting the day following the AMI shutdown occurs (i.e., on Day 2).
- Due to the significant manual effort required to simulate the shutdown assumptions on the individual customer level, FEI has instead modelled the loads coming off the system at the system level. This was done by determining the percent of the Lower Mainland load that

is from customers who will not receive the remote disconnect module (referred to as manual shutdown customers). This was found to be approximately 50 percent of the load. That is, approximately half of the Lower Mainland load is from manual shutdown customers, while the other half is from customers who will receive the remote disconnect module (referred to as remote shutdown customers). The modeling timeline, revised for this IR response, is described below:

1. Day 1 at 12:00 AM:
   - A no-flow event occurs off-system on the T-South pipeline.
   - FEI is made aware of the event and begins preparing Tilbury for sendout.
2. Day 1 at 2:00 AM:
   - Gas supply from T-South to the Lower Mainland ceases.
   - LNG sendout from Tilbury begins.
3. Day 1 at 4:00 AM:
   - Interruptible customers are offline.
4. Day 1 at 8:00 AM:
   - The total Lower Mainland load is reduced by 50 percent to simulate the remote shutoff customers being disconnected (50 percent of the total firm Lower Mainland load remains online).
5. Day 2 at 8:00 AM:
   - 17 percent[4] of the total Lower Mainland load goes offline to simulate the first set of manual shutdown customers being disconnected (33 percent of the total firm Lower Mainland load remains online).
6. Day 3 at 8:00 AM:
   - 17 percent of the total Lower Mainland load goes offline to simulate the second set of manual shutdown customers being disconnected (17 percent of the total firm Lower Mainland load remains online).
7. Day 4 at 8:00 AM:
   - 17 percent of the total Lower Mainland load goes offline to simulate the third set of manual shutdown customers being disconnected (0 percent of the total firm Lower Mainland load remains online). All customers are now offline.

To determine if a controlled shutdown is possible for each Supplemental Alternative under the modelling assumptions, FEI determined the percent of LNG tank volume utilization at the time when all customers are offline. A utilization greater than 100 percent indicates that more LNG

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

volume than is available was required to execute the controlled shutdown, and thus a controlled shutdown is not possible. The results for each Supplemental Alternative are discussed below.

***Supplemental Alternative 4 (Contingent):***

At the +4°C temperature condition, the Supplemental Alternative 4 (Contingent) support duration is extended by 2 hours (i.e., extended from 7 hours to 9 hours) due to the remote shutoff customers being disconnected at 8:00 AM. However, even with the remote shutoff customers being disconnected, the system load still exceeds the 150 MMcf/d regasification capacity and a shutdown occurs. As the shutdown occurs before the manual shutdown customers can be disconnected, the shutdown is uncontrolled.

Due to the regasification constraint, at the -1.4°C and -10°C temperature conditions, Supplemental Alternative 4 (Contingent) results in a shutdown prior to the remote shutoff customers being disconnected at 8:00 AM. As such, the support duration at these temperature conditions does not change, and the shutdown remains uncontrolled.

***Supplemental Alternative 4A (Contingent):***

At the +4°C and -1.4°C temperature conditions, the percent of LNG tank utilization is less than 100 percent at the time when all customers are offline. As a result, a controlled shutdown is possible for Supplemental Alternative 4A (Contingent) under the modelling assumptions. FEI notes that, from a planning perspective, Supplemental Alternative 4A does not consider a resiliency reserve and as such a controlled shutdown would not be possible.

At the -10°C temperature condition, Supplemental Alternative 4A (Contingent) results in a shutdown prior to the remote shutoff customers being disconnected at 8:00 AM. As such, the support duration at this temperature condition does not change, and the shutdown remains uncontrolled.

***Supplemental Alternative 8:***

At the +4°C, -1.4°C, and -10°C temperature conditions, the percent of LNG tank utilization is less than 100 percent at the time when all customers are offline. As such, with the modelling assumptions, Supplemental Alternative 8 is capable of a controlled shutdown at all temperature conditions considered in the analysis.

***Supplemental Alternative 9:***

At the +4°C, -1.4°C, and -10°C temperature conditions, the percent of LNG tank utilization is less than 100 percent at the time when all customers are offline. As such, with the modelling assumptions, Supplemental Alternative 9 is capable of a controlled shutdown at all temperature conditions considered in the analysis.

FEI notes that at the +4°C temperature condition, only 33 percent of the 2 Bcf resiliency reserve would have been utilized, meaning that 67 percent of the reserve was not used. This highlights the unrealistic nature of implementing the remote disconnect module only 8 hours after the no-flow event. In this hypothetical scenario, had FEI waited for more information to become available, a more favorable outcome could have been achieved. For example, had FEI fully depleted the 2 Bcf reserve, FEI could have supported all firm Lower Mainland customers for approximately 4.5 days. If the no-flow event was resolved within this duration, then no outages would have occurred. Even if the no-flow event lasted longer than 4.5 days, FEI could have supported customers while preparations were made, then executed a controlled shutdown.