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September 13, 2021

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

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 British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

FEI respectfully submits the attached response to BCOAPO IR No. 1 in the above noted Application.

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

1.0 Reference: PROJECT NEED

Exhibit B-1-4, page 3

Minimum Resiliency Objective

Preamble: FEI States:

"Upstream Supply Disruptions, While Rare, Do Occur and the Consequences Can Be Significant

The fact that FEI must obtain much of its natural gas supply via Westcoast's T-South system presents resiliency challenges. The potential for an interruption of supply from the T-South system is currently the largest supply risk facing FEI. Mitigating that risk is the objective of the Project."

1.1 In what year did FEI first identify the significant risk potential for supply interruption on the T-Source system?

Response:

Given that all of the gas supply to the Lower Mainland originates from a single point (the Huntingdon Station near Abbotsford) which is primarily supplied by the T-South system, FEI has long been aware of its exposure to upstream supply disruptions which could affect its ability to take gas from this delivery point.

FEI placed some reliance on the apparent redundancy inherent in the T-South system, which consists of two pipelines (though both are located in a single right of way). However, during the T-South rupture in October 2018, both pipelines were shut-in: one due to the rupture, and the other as a precautionary measure by Westcoast due to its proximity to the rupture and unknown condition. As such, the T-South Incident in October 2018 underscored that FEI's current reliance on a single pipeline system for most of its supply creates a challenge for FEI's system resiliency.

1.2 Has FEI previously identified and quantified the operational risk attributable to resiliency? If yes, please provide such analysis, if not, please explain why not.

Response:

Gas supply risk associated with regional infrastructure is commonly addressed in FEI's evidence in cost of capital proceedings, but these assessments have been more qualitative in nature.

The concept of "resiliency" has been gaining increased prominence in the industry. FEI began characterizing the operational risk related to T-South as a "resiliency" risk in its 2020-2021 Annual Contracting Plan L-31-20 Compliance Report filed with the BCUC on August 31, 2020. This document is included as Confidential Appendix C in the Confidential Application.

1.3 Given FEI's view that supply interruption from the T-South system is currently the largest supply risk facing FEI, how is FEI actively mitigating this risk in the interim before the Tilbury LNG Storage Facility project is constructed?

Response:

FEI is actively mitigating the risk of potential supply disruptions on the T-South system. Minor capacity and associated supply disruptions are managed by FEI holding a diverse portfolio of flexible resources as part of the Annual Contracting Plan (ACP). However, managing major supply disruptions that lead to longer-term capacity decreases, and that would affect the broader region, requires new physical storage and pipeline infrastructure as part of a resiliency portfolio, as described in the Application.

In terms of addressing minor capacity and associated supply disruptions, FEI mitigates this risk primarily through the strategies set out in its ACP. These strategies are summarized in the ACP Compliance Filing included as Confidential Appendix C to the Application (pages 26 to 28). For instance, FEI has enhanced the resiliency attributes of its gas supply portfolio by holding contingency resources on the T-South system, and by taking back Southern Crossing Pipeline (SCP) capacity. Contingency resources include supply, LNG storage, and/or pipeline infrastructure in excess of what is required to meet the load forecast for Rate Schedule 1 to 7 customers. FEI currently contracts for approximately 15 percent of additional capacity on the T-South system as a contingency resource. However, at present, the only opportunity for FEI to diversify its portfolio in terms of supply hubs and reduce its reliance on the T-South system has been taking back capacity on SCP that was previously contracted by a third party.

These contingency resources are held because they provide some resiliency benefits, particularly if there is reduced capacity on the T-South system, similar to what was experienced during Phase 3 of the T-South Incident. However, the resiliency value of these resources is limited and they do not insulate FEI from a major shutdown of T-South or other event that would restrict supply greater than 15 percent of the capacity of T-South (i.e., as occurred in Phases 1 and 2 of the T-South Incident). Currently, additional options for FEI to further mitigate the risk of no-flow supply interruptions on T-South are limited. Resources in the region are fully contracted, as illustrated in Table 4-7 of the Application, and constrained during the winter. Further, these resources are limited in their ability to physically provide gas to the FEI system.

FEI also recognizes the responsibility that Westcoast bears for providing safe, reliable service on its T-South system. T-South shippers agreed to additional integrity spending as part of the current settlement agreement with Westcoast. While an effective integrity program is important for helping to provide safe, reliable service, it is unable to fully mitigate all threats faced by a pipeline. Given the degree to which FEI, and more broadly the region, is dependent on a single pipeline system for the transportation of supply, the risk of a major supply disruption is most effectively mitigated through the resiliency portfolio described in the Application.

1.4 Is FEI's view that the T-South system that is currently the largest supply risk facing FEI results from the need to meet the minimum resiliency objective?

Response:

FEI confirms that the potential for an interruption of supply from the T-South system is currently the largest supply risk facing the Company. This is because the Lower Mainland is heavily dependent on the T-South system for supply due to limited pipeline interconnectivity in the region.

The Minimum Resiliency Planning Objective (MRPO) does not *create* supply risk, as the question seems to imply. Rather, as discussed in the response to BCOAPO IR1 1.5, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI.

1.5 In the absence of the Minimum Resiliency Objective, would the proposed Tilbury LNG Storage Expansion be necessary or required and please explain whether in the absence of this criteria whether the T-South system continues to represent FEI's largest supply risk?

Response:

Yes, in the absence of the MRPO, the proposed TLSE Project would still be necessary to address the resiliency need for the Lower Mainland service area.

For clarity, the MRPO does not *create* supply risk, as the question seems to imply. It is also not a general planning standard. The concept of the MRPO was developed by FEI to support the this Application; the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. The risk exists because of the configuration of the regional system and the location of FEI within that system, not *because of* the MRPO. Please also refer to the response to BCUC IR1 8.1.

FEI remains heavily reliant on the T-South system, and this dependence represents FEI's largest supply risk. Further, the TLSE Project will be replacing the 50 year old Tilbury Base Plant facility that provides operational and gas supply benefits to FEI and its customers.

2.0 Reference: PROJECT NEED

Exhibit B-1-4, page 14

Electric System Redundancy and Natural Gas Systems

Preamble: FEI states:

> "Based on industry experience, on average, a typical 80 km overhead electric transmission circuit is expected to experience one unplanned outage event per year. Since circuit outages are an expected occurrence in electric networks, asset redundancy is commonly employed to ensure compliance with minimum standards of reliability. The BC Mandatory Reliability Standards (MRS) require that the bulk electric system be planned and operated to withstand an unexpected outage of the single most critical system element, coincident with the forecast system peak load, while not experiencing any firm customer outages. This is referred to as the N-1 reliability criterion and is based on North American industry standards. These industry standards were developed and mandated following two major Northeast blackouts, one in 1965 and one in 2003. In other words, the cost of this necessary system redundancy is broadly accepted by electric operators and regulators in order to ensure adequate levels of customer service."

2.1 Please explain why "the cost of this necessary system redundancy is broadly accepted by electric operators and regulators in order to ensure adequate levels of customer service" has traditionally not been required or universally accepted by natural gas operators and regulators?

Response:

Constructing redundant pipeline capacity to address resiliency as the primary project objective has historically been considered economically inefficient. Given the very high costs of underground pipelines, together with their generally excellent reliability performance and long lifespans, operators have been incented to maximize pipeline contractual sales in order to mitigate rates to end users.

As stated in the *NERC 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* (p. 83): [1]

> FERC will generally not authorize new pipeline capacity unless customers have already committed to it (Firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, additional customers request firm service from a pipeline that then adds new facilities or improves existing facilities, results in new pipeline capacity closely matches the requirements of the new customers. If all of the pipeline's firm customers use their

[1] https://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

full capability, little or no excess pipeline capacity will be available. **This is a major difference between electric transmission and pipeline infrastructure construction.** Electric transmission does not necessarily need to be approved by FERC, but transmission must be built to support speculative growth and socialized cost. **Additionally, pipeline contingency planning standards, similar to transmission planning standards, do not exist.** However, this does not mean that the pipeline system is not redundant. First, buried steel pipelines are inherently robust than and, therefore more resilient to extreme weather than transmission wires. Second, pipelines use series of side-by-side pipelines (called "loops") that provide redundancy—even if one gets corroded, needs maintenance, or even loses integrity, the other loops can increase their pressure and make it up. The same is true of compressor stations." [Emphasis added.]

In summary, constructing additional pipelines with reserve capacity that was not fully contracted was perceived to be unnecessarily burdensome to ratepayers and would only increase costs in a highly competitive industry.

2.2 If not already provided through responses to BCUC IR series 10, please provide the Canadian natural gas LDC's who plan for and hold assets to provide the level of resiliency that FEI is seeking, the type of assets held, and the investment and annual operating costs associated with meeting their resiliency criteria?

Response:

Please refer to the response to BCUC IR1 10.4.1.

2.3 Please explain whether there are any natural gas industry standards or legal obligations requiring FEI to meet the resiliency objectives identified by FEI or are the resiliency objectives identified in its Application self-imposed?

Response:

There are no natural gas industry standards or regulatory obligations specifically requiring FEI to meet the resiliency objectives identified by FEI in the Application. However, FEI believes that planning and operating the gas system to prevent, withstand, and recover from system failures or unforeseen events is consistent with FEI's regulatory requirement under section 38 of the UCA to provide service which "[…] is in all respects adequate, safe, efficient, just and reasonable."

FEI notes that, as discussed in the response to BCOAPO IR1 1.5, the Minimum Resiliency Planning Objective (MRPO) is not a general planning standard applicable to the system. Rather, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI.

2.4 Please explain whether the event in October 2018 that gave rise to this Application was considered a force majeure event?

Response:

Both Westcoast and FEI declared *force majeure* as a result of the October 2018 event.

3.0 Reference: PROJECT NEED

Exhibit B-1-4, pages 24, 36

Customer Perspectives

Preamble: FEI states:

"Figure 3-1 below depicts the concepts of integrity, reliability, and resiliency as building blocks of customer service."

"Resiliency investments are, as Guidehouse notes, akin to purchasing insurance, where it is necessary to balance risk against cost of purchasing that insurance. It is impossible to eliminate all risk of system collapse, and it would be prohibitively expensive for customers to attempt to do so. FEI's approach to resiliency has kept cost in mind, having regard to the nature and extent of the risk."

3.1 Please explain whether redundancy is also akin to purchasing insurance?

Response:

The following response has been provided by Guidehouse:

Redundancy in the natural gas system is a by-product of the interconnectedness of the interstate transportation and storage system. This system, across North America, features multiple points for receipt and delivery of natural gas. The connectivity capabilities contribute to the ability of the natural gas system to respond to a supply or transportation disruption. In some natural gas distribution systems, redundancy is a critical and common element of system design and necessary for maintaining reliability and in some cases resiliency. Redundancy is integrated at all system levels, from individual components to market hubs and allows for failure to occur in one part of the system without major reliability impacts. Redundancy can provide an operational protection to system malfunctions; however, its ability to provide this protection is a function of its physical presence and its market availability. Hence redundancy alone, e.g., the presence of a pipeline or a storage facility without market availability, is not an insurance to high impact and/or catastrophic failure that may or may not be caused by external forces.

The following response has been provided by FEI:

FEI notes that Guidehouse's comments above are consistent with the *NERC 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* (p. 83)[2], which is quoted in the response to BCOAPO IR1 2.1. Please also refer to the responses to BCSEA IR1 2.1 and 2.2 for further discussion of how resiliency investments can be considered akin to insurance.

[2] https://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

3.2 Please discuss why cost implications and affordability for consumers was not considered as a building block factor of customer service?

Response:

The cost implications and affordability for customers were considered during the development of the TLSE Project Application. Please refer to Section 4 of the Application (specifically, Tables 4-3, 4-4 and 4-6) for the financial analysis of various Project alternatives and Section 6 for the financial analysis of FEI's preferred alternative. Please also refer to the responses to BCUC IR1 9.1 and 9.2.

3.3 Please discuss whether FEI has conducted (internally or externally by a firm) any customer research studies that seek insight into the cost at which customers are willing to pay (in isolation) for the level of security provided of rare events? Do customers willingness to pay for such insurance change when viewed along with significant potential future cost increases on account of aging infrastructure, climate, and the economic consequences flowing from a global pandemic? If no such research has been undertaken, why not?

Response:

Please refer to the response to BCUC IR1 7.5.

4.0 Reference: PROJECT NEED

Exhibit B-1-4, Section 3.2.2, page 26, lines 13-21

Annual Cost of Fuel

Preamble:

On page 234 of the Transcript, in response to a question on how much of the new Tilbury LNG tank storage capacity is reserved for resiliency in the event of an emergency, Mr. Leclair stated: "we'll always have three days of minimum supply reserved for our customers so then the incremental sort of differential to fill is far less."

4.1 Please provide the annual cost of holding three days of minimum supply assuming low, current and high fuel costs.

Response:

This response addresses BCOAPO IR1 4.1, 4.2 and 4.3.

The cost of holding three days minimum of supply is the carrying cost associated with the time between when the tank is filled, and when it is used (i.e., the emergency event). The cost of the fuel itself (i.e., natural gas commodity cost) does not factor into the financial analysis, as it is a flow-through and the TLSE Project does not directly increase or decrease the cost of natural gas. As discussed below, the carrying cost associated with holding three days minimum of supply is relatively modest. Further, the incremental cost of fuel between 2 and 3 Bcf is small and does not change the strong economies of scale that support a 3 Bcf tank. There are also gas supply benefits associated with the "third Bcf" that more than offset the incremental capital costs.

Calculating the Holding Cost

The 3 Bcf TLSE storage tank will be filled once initially and FEI will then hold a minimum of 2 Bcf of storage for resiliency purposes (with an additional 1 Bcf available for resiliency and other ancillary benefits), until the LNG is regasified for delivery to customers. For the time between when the LNG storage tank is first filled and when the LNG is first regasified (i.e., the period of time which FEI is "holding" the minimum supply of 2 Bcf), the value of this LNG inventory is recorded in Gas in Storage in FEI's rate base, attracting a return on rate base, which FEI equates to the annual cost of holding the LNG inventory.

FEI provides the table below for the commodity costs of the initial fill for both the 2 and 3 Bcf tank based on a range of commodity costs (Line 4 to 6). The table also includes the present value (PV) of the total commodity-related costs (Line 10 to 12) as well as the levelized annual costs of

holding the LNG inventories (Line 14 to 16) over a 67-year period[3]. FEI notes the following assumptions were used for the range of commodity costs:

- Low fuel cost is based on FEI's lowest cost of gas rates over the last 10 years (which occurred in 2016 at $1.141 per GJ);
- Current fuel cost is based on the current (September 2021) approved cost of gas rates at $2.844 per GJ; and
- High fuel cost is based on FEI's highest cost of gas rates over the last 10 years (which occurred in 2014 at $4.640 per GJ).

It can be seen from the table below that the impact of including the annual costs of holding the LNG inventory is small, with increases ranging from 0.2 to 0.9 percent (Lines 25 to 27) or equivalent increases in the levelized delivery rate ranging from $0.001 per GJ to $0.003 per GJ[4] (Lines 29 to 31) for the 2 Bcf tank. Similarly, the increases for the 3 Bcf tank are also small, ranging from 0.4 to 1.3 percent, with equivalent increases in the levelized delivery rate ranging from $0.001 per GJ to $0.004 per GJ.

For a complete financial evaluation, FEI also included in the table below the PV of the incremental revenue requirement (i.e., O&M expenses, depreciation, income tax, and earned return associated with the assets) for the 2 and 3 Bcf tanks (Line 19), the levelized annual cost of service (Line 20) and the levelized delivery rate impact (Line 21) over a 67-year analysis period as shown in Table 4-6 of the Application.

By including the commodity-related costs, the incremental increase between the 2 and 3 Bcf tank remains relatively small, ranging from $0.027 per GJ to $0.028 per GJ in levelized delivery rate impact (Line 39 to 41), which is equivalent to an annual bill impact ranging from $2.39 to $2.47 for the average residential customer with annual consumption of 90 GJs. As discussed previously, even with the commodity-related costs, there remain strong economies of scale that support a 3 Bcf tank. For instance, as the analysis in the table below shows, even under the high fuel cost scenario, the PV of annual cost of service and commodity related costs for the 3 Bcf tank is only about 10 percent higher than the 2 Bcf tank, yet the larger tank provides 50 percent more storage capacity. Further, this incremental increase in terms of the total PV of cost of service or the levelized delivery rate impact is outweighed by the additional benefits resulting from the additional 1 Bcf of storage capacity, as further discussed below.

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[3] For the purpose of determining the holding cost for the 3 Bcf scenario, FEI conservatively assumed it would be holding the full additional 1 Bcf of LNG for the entire year every year over the 67-year analysis period (as opposed to calculating the holding cost under the assumption that the "third Bcf" of storage may fluctuate during the year). Please refer to the response to BCUC IR1 30.3.1 which explains that there will be seasonal variations for the "third Bcf" of LNG storage available for gas supply and/or operational requirements, thus at any given time, the annual volume of LNG storage above the minimum 2 Bcf could be less (i.e., the volume could fluctuate between 2 and 3 Bcf). Accordingly, the holding costs of this additional Bcf could be less than the analysis shows.

[4] Rounded to 3 decimal places.

Offsetting Gas Supply Benefits of the "Third Bcf"

As demonstrated in the response to BCUC IR1 46.2, the ongoing benefits from the additional 1 Bcf of storage will outweigh the incremental capital and filling and holding costs for the additional 1 Bcf of storage (i.e., the "third Bcf"). Having access to this additional 1 Bcf of storage means that the gas supply value generated in the Tilbury Base Plant today will be maintained, thereby avoiding the need for FEI to secure 150 MMcf/day of additional gas supply from the market through commercial arrangements, which is estimated at approximately $30 million per year in 2021 dollars. In contrast, as shown in the table below, the incremental levelized annual cost of service, including the annual costs of holding the LNG commodity, over a 67-year period is approximately $5 million[5]. Ultimately, because of the gas supply benefits associated with the "third Bcf", the proposed TLSE Project with 3 Bcf of storage is less costly over the long term to FEI's customers than a 2 Bcf facility.

[5] Based on an incremental PV between 2 and 3 Bcf of $93 million on Line 35 of the Table below, calculated using the excel formula for annualized value = PMT(FEI's WACC of 5.47%, 67 years, $93 million).

Line	Particular	Reference	2 Bcf	3 Bcf	Incremental from 2 Bcf to 3 Bcf
1	Volume in GJ	1 Bcf = 1.055 PJ	2.1	3.2	
2					
3	**Cost of Initial Fill ($ million)**				
4	Low Fuel Cost	$1.141/GJ	2	4	2
5	Current Fuel Cost	$2.844/GJ	6	9	3
6	High Fuel Cost	$4.640/GJ	10	15	5
7					
8	**Annual Cost of Holding Initial Fill**				
9	PV of Annual Cost of Holding Initial Fill 67 years				
10	@ Low Fuel Cost ($ millions)		2	4	2
11	@ Current Fuel Cost ($ millions)		6	8	2
12	@ High Fuel Cost ($ millions)		9	14	5
13	Levelized Annual Cost of Holding Initial Fill 67 years				
14	@ Low Fuel Cost ($ millions)	See Note 1	0.1	0.2	0.1
15	@ Current Fuel Cost ($ millions)	See Note 1	0.3	0.5	0.1
16	@ High Fuel Cost ($ millions)	See Note 1	0.5	0.8	0.3
17					
18	**Cost of Service of LNG Facility (excl. Annual Cost of Holding Initial Fill)**				
19	PV of Annual Cost of Service of LNG Facility 67 years ($ millions)	Table 4-6 of Application	951	1,042	91
20	Levelized Annual Cost of Service of LNG Facility 67 years ($ millions)	See Note 2	54	59	5
21	Levelized Delivery Rate Impact 67 years ($/GJ)	Table 4-6 of Application	0.275	0.301	0.026
22					
23	**Impact from Annual Cost of Holding Initial Fill**				
24	Increase in Levelized Annual Cost				
25	@ Low Fuel Cost (%)	Line 14 / Line 20	0.2%	0.4%	0.2%
26	@ Current Fuel Cost (%)	Line 15 / Line 20	0.6%	0.8%	0.1%
27	@ High Fuel Cost (%)	Line 16 / Line 20	0.9%	1.3%	0.4%
28	Equivalent Increase in Levelized Delivery Rate Impact				
29	@ Low Fuel Cost ($/GJ)	Line 21 / Line 25	0.001	0.001	0.001
30	@ Current Fuel Cost ($/GJ)	Line 21 / Line 26	0.002	0.002	0.001
31	@ High Fuel Cost ($/GJ)	Line 21 / Line 27	0.003	0.004	0.001
32					
33	**Total PV of Annual Cost of Service and Annual Cost of Holding Initial Fill 67 years**				
34	@ Low Fuel Cost ($ millions)	Line 10 + Line 19	953	1,046	93
35	@ Current Fuel Cost ($ millions)	Line 11 + Line 19	957	1,050	93
36	@ High Fuel Cost ($ millions)	Line 12 + Line 19	960	1,056	96
37					
38	**Equivalent Levelized Delivery Rate Impact (incl. Annual Cost of Holding Initial Fill) 67 years**				
39	@ Low Fuel Cost ($/GJ)	Line 21 + Line 29	0.276	0.302	0.027
40	@ Current Fuel Cost ($/GJ)	Line 21 + Line 30	0.277	0.303	0.027
41	@ High Fuel Cost ($/GJ)	Line 21 + Line 31	0.278	0.305	0.028
	Note 1: Excel Formula for Annualized Value = PMT(Discount Rate @ FEI's WACC of 5.47%, 67 years, PV of Fuel Costs from Line 14 to 16)				
	Note 2: Excel Formula for Annualized Value = PMT(Discount Rate @ FEI's WACC of 5.47%, 67 years, Line 20)				

4.2 The total supply cost to completely fill the Tilbury LNG Storage Facility assuming the same underlying cost of fuel as per IR 9.1?

Response:

FEI understands the question is referring to BCOAPO IR1 4.1 and not IR1 9.1.

Please refer to the response to BCOAPO IR1 4.1.

4.3 To the extent there is a difference between the minimum three days of supply and IR 4.2 above, please explain the rationale for constructing a facility greater than that required to meet FEI's minimum resiliency objectives.

Response:

Please refer to the response to BCOAPO IR1 4.1 which demonstrates that even after considering commodity costs, the 3 Bcf tank is the preferred alternative.

5.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATES

Exhibit B-1-4, page 11, lines 8-15; page 14, lines 1-2

Minimum Resiliency Objective

Preamble: FEI states:

> "The average annual delivery rate impact over the six years from 2022 to 2027 is estimated to be 1.47 percent annually or $0.068 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $6.12 per year over the six years. The levelized delivery rate impact is 6.67 percent, which is equivalent to $0.301 per GJ for a typical FEI residential customer over the life of the assets." (page 11)

> "The Application is premised on the need to make resiliency investments to address existing exposure to disruption in regional pipeline flows." (page 14)

5.1 Please explain the need and timing required in order that Minimum Resiliency Planning Objective criteria be met on all portions of FEI's system.

Response:

As discussed in the responses to BCUC IR1 8.1 and BCOAPO IR1 1.5, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard, as implied by the question.

The Lower Mainland service area is FEI's largest demand center, and its system configuration requires greater resiliency enhancements compared to the Vancouver Island or Interior service areas. For example, the amount of storage at Mt. Hayes currently gives FEI multiple days of supply to withstand a no-flow event within the Vancouver Island service area.

While the MRPO targets the needs of the Lower Mainland, the TLSE Project will also improve resiliency for the Interior service area. As FEI discussed in the TLSE Workshop, the storage provided by the TLSE facility would also allow FEI to meet customer demand for the vast majority of the year even if one of the gas transmission lines in the Interior was disrupted.[6] For example, if there was reduced capacity or a no-flow event on the TC Energy pipeline that provides supply for the FEI Interior Transmission System (ITS) at Yahk, the TLSE Project could also help FEI manage such an event. FEI could divert supply from the T-South system into the ITS to replace the lost capacity from TC Energy, and then use the TLSE storage and regasification to back-fill the reduced supply into the Lower Mainland which would have previously been supplied from the T-South system.

[6] Transcript Volume 1, Web-Based Workshop March 11, 2021, pp. 187-188.

5.2 Please provide the overall level of additional investment costs and impact to customer rates required in the next 20 years to meet the Minimum Resiliency Planning Objective.

Response:

As discussed in the response to BCOAPO IR1 5.1, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard, as implied by the question. The proposed TLSE Project will meet this objective.

The majority of costs and therefore impact to customer rates related to the TLSE Project will occur from 2022 to 2027. Table 6-6 of the Application provides the year-over-year delivery rate impact due to the TLSE Project from 2022 to 2027 (third row of Table 6-6). The costs forecast to be incurred beyond 2027 for the TLSE Project are related to incremental sustainment capital for the mechanical equipment and future capital replacement for the regasification and auxiliary systems after 40 years. These incremental capital costs are discussed in Section 6.3 of the Application (page 163). Please refer to the table below for the incremental delivery rate impact over the next 20 years due to the aforementioned TLSE Project costs.

Line	Year	Incremental % Delivery Rate Impact due to TLSE Project (Year-over-Year)
1	2022	(0.02%)
2	2023	0.06%
3	2024	0.10%
4	2025	2.46%
5	2026	1.52%
6	2027	4.71%
7	2028	0.08%
8	2029	0.09%
9	2030	0.04%
10	2031	0.03%
11	2032	0.02%
12	2033	0.01%
13	2034	0.00%
14	2035	(0.00%)
15	2036	(0.01%)
16	2037	(0.02%)
17	2038	(0.02%)
18	2039	(0.03%)
19	2040	(0.03%)
20	2041	(0.03%)

5.3 Please discuss how FEI has established prioritization of additional investment cost requirements to meet the Minimum Resiliency Planning Objective.

Response:

As discussed in the response to BCOAPO IR1 5.1, FEI's MRPO is simply a way of articulating the specific identified risk to the Lower Mainland service area associated with a no-flow event on the T-South system. It is not a general planning standard, as implied by the question. The proposed TLSE Project will meet this objective.

FEI discusses the incremental sustainment capital costs for the TLSE Project in the response to BCOAPO IR1 5.2. These costs will be incurred when required and will be prioritized using FEI's capital planning processes described in the response to BCOAPO IR1 5.6.

Other resiliency investments such as Load Management and/or Diverse Pipelines are complementary, but will not on their own, or in combination, allow FEI to meet the MRPO without the TLSE Project. As such, FEI prioritized the TLSE Project ahead of other alternatives as it is the most effective solution to mitigate the identified lack of resiliency for the Lower Mainland system. Please also refer to the response to BCUC IR1 17.1.

5.4 Please file FEI's system planning analysis reflecting its Minimum Resiliency Planning Objective criteria. If no such analysis has been undertaken, please discuss in detail why not.

Response:

As discussed in the response to BCOAPO IR1 5.1, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard, as implied by the question.

The rationale and analysis behind the MRPO is set out in Section 3 of the Application. In essence, the MRPO is based on several factors, but primarily the need to buy time to assess options, to withstand a 3-day no-flow event on the T-South system, and in the worst case scenario, to perform a controlled shutdown of the system. Please also refer to the response to BCUC IR1 8.1.

An extensive system planning analysis, including FEI's supply and demand forecasts as well as regional gas supply, was used to evaluate potential solutions and their ability to mitigate supply disruptions in various scenarios, most importantly during cold winter periods. This analysis is contained in Sections 3.4 and 3.5 of the Application.

5.5 Please file FEI's most current Long Term Resource Plan.

Response:

FEI's most recent Long Term Gas Resource Plan (LGTRP) was filed on December 14, 2017 (2017 LTGRP) and was accepted by the BCUC on February 25, 2019 pursuant to Order G-39-19. The 2017 LTGRP is available at the following link:

https://www.bcuc.com/Documents/Proceedings/2018/DOC_50742_B-1_FEI-2017-Long-Term-Gas-Resource-Plan.pdf.

In providing this link, FEI confirms that it is intending the document to form part of the evidentiary record in this proceeding.

5.6 Please discuss FEI's approach to capital planning organizationally. That is, please explain FEI's capital spend approach in terms of, for example, prioritization of aging infrastructure investment (sustaining capital), investment required to address decarbonization policy, capital spend related to system growth, capital spend related to meeting the Minimum Resiliency Planning Objective?

Response:

As discussed in the response to BCOAPO IR1 5.1, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard, as implied by the question. The proposed TLSE Project will meet this objective.

FEI undertakes a rigorous capital planning process when assessing both its short and long-term capital needs to ensure it proposes and constructs prudent projects with a holistic view of its system. Please refer to the responses to BCUC IR1 14.1, 14.4 and 14.5 for a discussion of FEI's prioritization of major capital projects, including the TLSE Project.

With regard to long-term capital planning, FEI develops these plans as part of the Long-Term Gas Resource Plan (LTGRP), which is filed approximately every five years with the BCUC and subject to a public review process. As part of the LTGRP development, FEI considers issues such as decarbonization policy and system load growth. In response to BCOAPO IR1 5.5, FEI has provided its most recently approved LTGRP, and, as explained in the response to BCOAPO IR1 7.2, FEI plans to file its next LTGRP with the BCUC in 2022.

FEI provides the following additional information on its short-term sustainment/growth capital planning processes.

FEI's proposed plan for sustainment capital work is provided to the BCUC for approval as part of its revenue requirement applications. FEI is currently operating under a multi-year rate plan (MRP) for 2020 through 2024 which was approved by Order G-165-20. As part of Order G-165-20, FEI's annual forecast for regular sustainment and other capital was approved for 2020 through 2022, and FEI was directed to file updated regular sustainment and other capital forecasts for 2023 and 2024 as part of the annual review for 2023 delivery rates. FEI utilizes Asset Investment Planning tools for planning and allocating funds amongst its portfolio of sustainment capital

projects. This allows FEI's Asset Management department to complete standardized evaluations of the value of each individual investment and the ratio of this benefit to the estimated cost. FEI is then able to optimize its sustainment capital plan to achieve the greatest value each year based on limiting criteria such as an approved sustainment capital budget. Each year, the investments in the sustainment capital portfolio that are not in execution are subjected to optimization again to determine the optimized capital sustainment plan for the following years.

System growth projects are customer-driven and are not prioritized against sustainment capital projects. FEI is obligated under Section 28 of the UCA to connect new customers who request natural gas service and are nearby a supply line. The mechanism for approval of growth capital expenditures changes depending on the rate-setting structure established by the BCUC. As previously described, FEI is operating under the 2020-2024 MRP, under which FEI's growth capital expenditures are established annually by an approved formula.

6.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATES

Exhibit B-1-4, page 11; Table 6-6, page 168; Transcript page 234

Rate Impacts and Cost Allocation

Preamble: FEI states:

> "…the Project will result in a cumulative delivery rate impact of 9.07 percent compared to FEI's 2021 approved delivery rates when all construction is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the six years from 2022 to 2027 is estimated to be 1.47 percent annually or $0.068 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $6.12 per year over the six years. The levelized delivery rate impact is 6.67 percent, which is equivalent to $0.301 per GJ for a typical FEI residential customer over the life of the assets."

6.1 Please provide FEI's currently approved total Revenue Requirement as well as Rate Base.

Response:

FEI's currently approved revenue requirement and rate base are $1,445.435 million and $5,212.439 million, respectively.[7] FEI's currently approved delivery margin (used to calculate the delivery rate impacts shown in this Application) is $879.479 million.

6.2 In the event that cost overruns occur beyond those reflected in current estimates, please provide the overall delivery rate impact in the scenario where 1) cost overruns are 25% greater than reflected in current estimates, 2) cost overruns are 50% greater than reflected in current estimates and 3) cost overruns are double that those reflected in current estimates.

Response:

Please refer to the following table, which provides the levelized rate impact for the three scenarios requested, applying the requested percentage increases to the Project Capital Cost including contingency.

[7] Compliance Filing to FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20.

FEI notes that, consistent with the BCUC's 2015 CPCN Application Guidelines[8], the TLSE Project cost estimate has been prepared to an AACE Class 3 level of definition. As per AACE Recommended Practice 18R-97, a Class 3 estimate typically has an expected accuracy range between -10% to -20% on the low side, and +10% to +30% on the high side, at an 80 percent confidence interval. As such, a 25 percent Project cost increase would still be within the typical Class 3 expected accuracy range.

Particular	Reference (As Estimated)	As Estimated	25% Greater	50% Greater	100% Greater
Total Project Capital Costs, 2020$ ($ millions)	Table 6-2, Line 7, Column 1	637.303	796.629	955.955	1,274.607
Levelized Delivery Rate Impact 67 years (%)	Table 6-3, Line 12	6.67%	7.68%	8.69%	10.72%
Levelized Delivery Rate Impact 67 years ($/GJ)	Table 6-3, Line 13	0.301	0.346	0.392	0.484

6.3 Please explain how the 9.07% was arrived at and identify all underlying assumptions.

Response:

The TLSE Project will be completed in phases, with assets entering rate base from 2022 to 2027 which results in incremental delivery rate impacts each year from 2022 to 2027. The 9.07 percent is the cumulative (i.e., total) delivery rate impact of the TLSE Project when all assets have entered FEI's rate base by 2027. The 9.07 percent is calculated based on the incremental revenue requirement in 2027 due to the TLSE Project (i.e., the cost of service of the TLSE Project when all assets have entered rate base) compared to FEI's 2021 approved non-bypass delivery margin, with the result being the percentage increase from FEI's 2021 approved delivery margin.

The table below provides the calculation of the 9.07 percent cumulative delivery rate impact from the TLSE Project. The actual delivery rate impacts will depend on both the actual costs that enter rate base each year and the approved revenue requirement at that time.

Line	Particular	Reference	2027
1	Incremental Revenue Requirement to 2021 Approved ($ millions)	Table 6-6 of Application (2027)	79.799
2	2021 Approved Delivery Margin, non-bypass ($ millions)	G-319-20	879.479
3			
4	Cumulative Delivery Rate Impact in 2027	Line 1 / Line 2	9.07%

[8] https://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf.

6.4 Table 6-6 identifies the impacts by year beginning in 2022 through to 2027. Please confirm that the total cumulative increase in delivery rates is approximately 16% (that is, -0.02% +0.04%+0.14%+2.6%+4.17%+9,07%)?

Response:

Not confirmed. The cumulative delivery rate impact of the TLSE Project is 9.07 percent when all assets have entered FEI's rate base as discussed in the response to BCOAPO IR1 6.3.

The delivery rate impacts shown in the second row of Table 6-6 of the Application (referenced in question 6.4 above) are the cumulative delivery rate impacts for each year from 2022 to 2027 due to the TLSE Project when compared to the 2021 approved delivery margin. Please see the table below for the calculation of the second row amounts for each year from 2022 to 2027. For further clarity, the delivery rate impacts shown here are all compared to the 2021 approved delivery margin (i.e., the percentage increase from the 2021 approved non-bypass delivery margin); as such, the impacts in percentages are not additive.

Line	Particular	Reference	2022	2023	2024	2025	2026	2027
1	Incremental Revenue Requirement to 2021 Approved ($ millions)	Table 6-6 of Application	(0.162)	0.361	1.274	22.909	36.651	79.799
2	2021 Approved Delivery Margin, non-bypass ($ millions)	G-319-20	879.479	879.479	879.479	879.479	879.479	879.479
3								
4	**Cumulative Delivery Rate Impact (%) when compared to 2021 Approved**	**Line 1 / Line 2**	**-0.02%**	**0.04%**	**0.14%**	**2.60%**	**4.17%**	**9.07%**

6.5 Is the 9.07% and 16% delivery rate increase based on a levelized approach to derive the rate impact? If yes, please provide calculation the overall delivery rate impact as derived in typical utility ratemaking (i.e not levelized) and provide a discussion of the underlying assumptions.

Response:

The 9.07 percent delivery rate impact in 2027 shown in Table 6-6 of the Application is not based on a levelized approach. Please refer to the response to BCOAPO IR1 6.3 for the calculation of the 9.07 percent. FEI assumes the reference to "16%" in this information request is referring to BCOAPO's own calculation shown in BCOAPO IR1 6.4. As explained in that IR response, the 16 percent value is an incorrect assessment of the delivery rate impact of the TLSE Project.

The levelized approach (which is an accepted utility ratemaking concept utilized when evaluating projects or rate impacts over multiple years) is discussed in the response to BCOAPO IR1 6.6.

6.6 Please explain how the 6.67 percent for a typical residential customer over the life of the assets was derived.

Response:

The 6.67 percent shown in Table 6-3 of the Application is the levelized delivery rate impact due to the TLSE Project over a 67-year analysis period. FEI notes this is the levelized delivery rate impact for all of FEI's non-bypass customers, not just for residential customers. The table below shows the calculation of the 6.67 percent.

Line	Particular	Reference	Amount
1	PV of Incremental Revenue Requirement over 67 years ($ millions)	Table 6-3 of the Application, Line 8	1,041.925
2			
3	2021 Approved Delivery Margin, non-bypass ($ millions)	G-319-20	879.479
4	PV of FEI 2021 Approved Delivery Margin over 67 years ($ millions)	-PV(Discount Rate (Line 7), 67 years, Annual Amount (Line 3))	15,624.421
5	**Levelized Delivery Rate Impact over 67 years (%)**	**Line 1 / Line 4**	**6.67%**
6			
7	FEI's After-Tax WACC (%)	G-319-20	5.47%

For clarity, the present value (PV) of the incremental revenue requirement (Line 1) and the PV of the 2021 approved delivery margin (Line 4) for non-bypass customers are both calculated using the discount rate of 5.47 percent (Line 7), which is equivalent to FEI's 2021 approved after-tax weighted average cost of capital (WACC).

FEI also notes that the PV of FEI's 2021 approved delivery margin (Line 4) is the present value of an annuity amount equivalent to the 2021 approved delivery margin (i.e., $879.479 million, Line 3) over a period of 67 years with a discount rate of 5.47 percent. The reference column for Line 4 shows the Excel formula used for calculating the PV of the delivery margin over the 67-year period.

6.7 Please provide the rate impact for a typical residential customer in 2027 assuming a typical ratemaking approach (reflecting the anticipated cost additions to rate base and revenue requirement).

Response:

The total (or cumulative) delivery rate impact due to the TLSE Project is 9.07 percent in 2027 for FEI's non-bypass customers, including residential customers, when compared to FEI's 2021 approved delivery margin. This is equivalent to a $0.609 per GJ total delivery rate impact when

compared to 2021 approved delivery rates[9]. For a typical residential customer consuming 90 GJs per year, the total cumulative impact to the annual bill over the years 2022 to 2027 would be approximately $55.

6.8 Is it anticipated there will be a disproportionate impact by rate class as a result of the Tilbury LNG Storage costs? Please provide the proforma delivery rate impacts in 2027 by class both assuming the typical utility ratemaking approach as well as reflecting a levelized approach.

Response:

There will be no disproportional impact on delivery rates by rate class. During FEI's annual rate-setting process, all non-bypass customers have the same percentage increase applied to the existing delivery margin of each rate class. As such, the total effective delivery rate impact of 9.07 percent in 2027 due to the TLSE Project when compared to the 2021 approved delivery margin applies to all of FEI's non-bypass customers, including residential customers. Similarly, the 6.67 percent levelized delivery rate impact due to the TLSE Project over a 67-year analysis period applies to all of FEI's non-bypass rate classes, including residential customers.

6.9 Please provide the anticipated annualized delivery rate impact based on a typical utility ratemaking approach associated with the costs to operate and maintain the Tilbury LNG Storage facility including the cost of the fuel at current costs.

Response:

The financial analysis and the delivery rate impacts provided in Section 6 of the Application already include the operations and maintenance (O&M) costs for the proposed 3 Bcf LNG storage tank and the new 800 MMcf/day regasification equipment, inclusive of fuel costs and electricity required for the LNG production.

Please refer to the response to BCOAPO IR1 4.1 for a discussion of commodity costs and the gas supply benefits of the TLSE Project.

[9] $0.609/GJ = FEI's 2021 approved residential delivery margin of $532.207 million x 9.07% / FEI's 2021 approved residential demand forecast of 79,332.3 TJs.

6.10 Please update the 6.67 percent levelized delivery rate impact to incorporate the anticipated annual costs to operate and maintain the Tilbury LNG Storage facility including the cost of the fuel (over the life of the plant).

Response:

Please refer to the response to BCOAPO IR1 6.9.

6.11 If not already provided in response to BCUC IR 1-4.6, please provide the overall cost per GJ of addressing the event in October 2018.

Response:

Please refer to the response to BCUC IR1 4.6.

7.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATES

Exhibit B-1-4, page 11

Future Rate Impacts

Preamble: BCUC IR 14.0 states:

> FEI's projects currently before the BCUC requiring CPCN approval include: Pattullo Gas Line Replacement, Okanagan Capacity Upgrades, Transmission Integrity Management Capabilities (Coastal Transmission System and Interior Transmission System), TLSE, and Automated Metering Infrastructure,
>
> 14.6 Please discuss the estimated cumulative rate impact of all of FEI's anticipated major projects listed above and include any major projects which may not have been listed which are expected to have an impact on rates over the next 10 years.

7.1 Further to BCUC IR 14.6, please also include cost impacts in order to meet FEI's Minimum Resiliency Planning Objective on all FEI's system.

Response:

As discussed in the response to BCOAPO IR1 1.5, the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard, as implied by the question. FEI also discusses in that response how, even though the TLSE Project is intended to meet a specific resiliency need for the Lower Mainland, it will also improve resiliency for the Interior service area.

As described in the Application, and discussed in the TLSE Workshop, the minimum storage required to meet FEI's MRPO is 2 Bcf which would have a levelized delivery rate impact over a 67-year analysis period of 6.09 percent, as shown in Table 4-6.

If the potential value of ancillary benefits associated with an additional 1 Bcf is considered, the 3 Bcf tank is actually less costly for ratepayers than a 2 Bcf tank. Please refer to the response to BCUC IR1 46.2 where FEI explains the additional value provided by the gas supply benefits associated with the additional 1 Bcf storage, which is estimated to be approximately $405 million in present value over 67 years (based on approximately $30 million per year in 2021 dollars). This amount is in excess of the incremental cost of service for the additional 1 Bcf storage, which is estimated to be approximately $91 million in present value over 67 years. In summary, when considering these additional benefits, the 3 Bcf tank is less costly for FEI's customers than a 2 Bcf tank over a 67-year period.

7.2 Please identify, discuss and quantify the impacts on a proforma basis, to customer rates over the next 10 years to address matters such as aging infrastructure, climate change (and the requirement to meet provincial and federal environmental targets) including price elasticity effects (resulting from raising prices) and flat or declining customer consumption.

Response:

FEI does not have a forecast of delivery rate changes for the next 10 years, although the response to BCUC IR1 14.6 provides a 10-year cumulative effective rate increase[10] due to FEI's completed, in-progress, and anticipated major projects. In that response, FEI explains that the cumulative rate impact is illustrative only and does not represent FEI's estimated rate increases for the years shown.

A forecast of rate impacts over the next 20 years that considers infrastructure needs, environmental and climate change targets/policies, and changes in customer consumption levels is more appropriately considered as part of FEI's Long Term Gas Resource Plan (LTGRP) proceeding, as the LTGRP will consider multiple factors including those listed above. FEI's next LTGRP is planned to be filed with the BCUC in 2022.

Please also refer to the response to CEC Confidential IR1 73.1.

7.3 Please provide a table of the changes in FEI's average delivery rate changes implemented since 2011 and include forecasted delivery rate changes anticipated for each year for the next 10-year period (to 2031) as per 7.2 above and assuming all applied for projects are approved as proposed

Response:

The following table lists the effective delivery rate changes approved from 2011 to 2021. FEI has also provided the forecast 2022 effective delivery rate change as proposed in FEI's Annual Review for 2022 Delivery Rates application filed with the BCUC on July 30, 2021. Please refer to the response to BCOAPO IR1 7.2 for a discussion of 10 year delivery rate change forecasts.

[10] Includes both delivery and commodity charges.

Particular	2011 Approved	2012 Approved	2013 Approved	2014 Approved	2015 Approved	2016 Approved	2017 Approved	2018 Approved	2019 Approved	2020 Approved	2021 Approved	2022 (Forecast)
Effective Delivery Rate Change, non-bypass (%)	2.10%	4.42%	6.24%	1.87%	0.71%	1.79%	0.00%	0.00%	1.10%	2.00%	6.62%	8.07%
BCUC Order	G-141-09 & G-158-09	G-44-12	G-44-12	G-138-14	G-86-13 & G-106-15	G-193-15	G-182-16	G-196-17	G-237-18 & G-10-19	G-319-20	G-319-20	n/a

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8.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATES

Exhibit B-1-4, page 160

Rate Impacts and Cost Allocation

Preamble: FEI states:

> "FEI has performed a financial evaluation of the Project based on the present value (PV) of the incremental revenue requirement and the levelized delivery rate impact to FEI's non-bypass customers over a 67-year analysis period."

8.1 Please describe the nature of service required of bypass customers, the lengths of their contracts, and total annual revenue received.

Response:

All bypass customers are located in the Interior region of FEI's service territory and are within a relatively short distance from the upstream pipeline (Enbridge's Westcoast pipeline). As explained in FEI's 2016 Rate Design Application, the key difference between a bypass customer and a non-bypass customer is that non-bypass customers take service under the applicable BCUC-approved rate schedules as endorsed in FEI's tariff. In contrast, bypass customers have negotiated, BCUC-approved contracts and rates that are different from the standard applicable rate schedules.

The original bypass agreements arose because certain customers that were close to the upstream pipeline were seeking to build their own infrastructure and avoid purchasing service from the utility (i.e., bypass the utility). Rather than having the customer avoid taking utility service altogether, the negotiated bypass rates ensured that the facility remained a customer of the utility and contributed incremental revenue that benefits all customers. The negotiated bypass rates are long-term contracts are based upon the costs if the customer were to leave the system and build, own, and operate their own pipeline from the upstream supply directly to their facility.

The principle for bypass rates is to recognize the possibility of a bypass and seek to retain the customer on the system to avoid stranding infrastructure and the loss of delivery revenue while also avoiding the need to construct a physical bypass pipeline. The concept of bypass rates was supported by government policy to encourage the industrial customer and the utility to negotiate a competitive transportation agreement and to avoid building unnecessary infrastructure, while also allowing the utility to maintain service to the customer. Bypass agreements are individually-negotiated long-term contracts that include extension provisions. The total 2021 approved annual revenue forecast from FEI's 11 bypass customers is $1.329 million.[11]

[11] Approved by Order G-319-20.

8.2 Please provide the rationale of excluding bypass customers in the analysis recognizing the long-life of the asset? Is it reasonable to expect that some contribution to the Tilbury LNG Storage costs be made by these customers?

Response:

As discussed in the response to BCOAPO IR1 8.1, bypass customers are large industrial customers located within a reasonably short distance from an upstream pipeline. Their applicable rates are negotiated with long-term agreements and are set only based on the costs to construct as well as to operate the pipeline between the bypass customer and the upstream pipeline. The logic for these agreements is that, unless a rate is based on the pipeline cost, the party would build its own pipeline (bypass the system).

All bypass rates are reviewed and approved by the BCUC. Given that bypass rates are set through long-term agreements and based on the costs of the pipeline only, they are not affected by the periodic adjustments to FEI's delivery rates. As such, bypass customers are reasonably excluded from the delivery rate impact analysis completed for the TLSE Project.

9.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATES

Exhibit B-1-4, page 168

Used and Usefulness of Assets

Preamble: FEI states:

> "2025 and 2026: Delivery rates will be impacted in 2025 and 2026 as the assets for the regasification equipment, auxiliary system, and ground improvements are scheduled to be placed in service in 2024 and 2025, and will be transferred to rate base on January 1 of 2025 and 2026, respectively…
>
> 2027: Delivery rates will be impacted in 2027 as the assets related to the new 3 Bcf LNG tank are scheduled to be placed in service in 2026, and will be transferred to rate base on January 1 of 2027...)

9.1 Please discuss the used and usefulness of the assets associated with regasification equipment, auxiliary system, and ground improvements that will become operational in 2025 and 2026 in the context of meeting the minimum resiliency objectives driving the Tilbury LNG investment, in the absence of the LNG tank which is not scheduled to become operational until 2027?

Response:

The regasification equipment, auxiliary systems, and ground improvements (i.e., the portion of ground improvements associated with the regasification equipment and auxiliary systems) that will enter rate base in 2025 and 2026 will be operational and therefore considered used and useful in providing service to FEI's customers.

The Tilbury Base Plant is anticipated to be removed in 2025; therefore, in order to provide continuous regasification capability to support peak demand and gas supply needs in the interval between when the Base Plant is being removed and prior to the new 3 Bcf tank being complete and operational, use of the new regasification equipment as well as the supporting auxiliary systems and ground improvements will be necessary. As discussed in Sections 5.3.3.1 and 5.3.3.2 of the Application, the new regasification equipment and supporting auxiliary systems will also be interconnected with the existing Tilbury 1A facility. This will provide the ability to send out natural gas using the new regasification equipment from either the proposed new 3 Bcf tank or the existing Tilbury 1A tank (prior to the completion of the 3 Bcf tank), if needed in the event of emergency.

10.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS

Exhibit B-1-4, Section 6.4.4, page 165

Deferral Account Amortization Period

Preamble: FEI states

"Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to ratebase on January 1 of the year following BCUC approval of the Application and commence amortization over a three-year period thereafter."

10.1 Please describe the nature and type of the Preliminary Stage Development costs incurred and proposed to be deferred.

Response:

The table below provides a breakdown of the $1.546 million of Preliminary Stage Development costs referenced in Table 6-5 of the Application. An explanation of the activities is provided following the table.

Particulars	Amount $000's
Environmental Assessment	
Project Services	
Communications	$ 68
Community Relations	105
Indigenous Relations	102
Legal	85
Project Management	139
Subtotal	499
Project Engineering and Development	
Engineering - Design	863
Project Services	
Environment & Archeology	72
Procurement	1
Project Management	111
Subtotal	1,047
Total Preliminary Stage Development	**$ 1,546**

The Preliminary Stage Development Costs of $1.546 million include actual costs allocated to FEI up to March 31, 2020 associated with the Environmental Assessment (EA) review process ($0.499 million) and the preliminary engineering and development related to the TLSE Project alternatives assessment ($1.047 million).

EA costs include those for planning and development of an Initial Project Description (IPD) under the new and proposed federal and provincial Environmental Assessment acts. Activities included: meetings with both the BC Environmental Assessment Office and Impact Assessment Agency of Canada to understand the new requirements and process; development and drafting of the IPD; engagement of an environmental consultant to support content development of the IPD; early engagement with Indigenous groups and community stakeholders for input into the IPD; and translations to French in accordance with the BC and Canada EA requirements.

Please refer to the response to BCUC IR1 47.1 for a discussion of how costs for the EA are allocated as between FEI and the non-regulated FortisBC Holdings Inc. (which is also a proponent in the EA) to ensure that FEI customers are only paying for an appropriate share of the EA costs.

The Engineering and Development costs are associated with developing the engineering deliverables for the TLSE Project to the appropriate level for the CPCN Application. Project Management includes costs related to schedule oversight and project controls. Environment and archeology costs are for archeology assessments for planning and preliminary work on the Tilbury site.

10.2 In addition to the scenarios requested by the BCUC in IR 44.3, please provide delivery rate impact scenarios 1) whereby Application and Preliminary Stage Development Costs are deferred over a five-year period and 2) whereby Application costs are deferred over a three-year period as proposed and Preliminary Stage Development costs are recovered over the life of the asset.

Response:

Please refer to the response to BCUC IR1 44.1 for the scenario of amortizing the Application and Preliminary Stage Development Costs deferral account over a five-year period.

For the scenario of amortizing only the Application costs through the deferral account over a three-year period while recovering the preliminary stage development costs over the life of the assets (i.e., by capitalizing the preliminary stage development costs), please refer to the table below which provides the present value of the incremental revenue requirement and the levelized delivery rate impact over a 67-year analysis period.

Capitalizing the preliminary stage development costs over the life of the asset (i.e., "Scenario #2" in the table below) slightly increases the present value of the incremental revenue requirement over the 67-year period by approximately $0.243 million or 0.023 percent (see Line 1 in the table below). However, the levelized delivery rate impact remains at 6.67 percent when rounded to two decimal places, or $0.301 per GJ when rounded to three decimal places.

Line	Particular	TLSE Project as proposed (Table 6-3 of the Application)	Scenario #2 (Amortize Application over 3-year and Capitalize Preliminary Starge Development Costs over life of assets)
1	PV of Incremental Revenue Requirement 67 years ($ million)	$ 1,041.925	$ 1,042.168
2			
3	Levelized Delivery Rate Impact 67 years (%)	6.67%	6.67%
4	Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.301

1

2

11.0 Reference: CONSULTATION

Exhibit B-1-4, Section 8.2, page 185, 198-199

Indigenous Consultation and Engagement Timing

11.1 Please discuss whether any serious concerns about the proposed project have been raised as part of FEI's consultation process that might have significant impacts, either to the timing or to the economics of the business case for this project.

Response:

As they are entitled to do, Indigenous groups are participating in the EA. FEI and FortisBC Holdings Inc. have been engaging with Indigenous groups to discuss and understand concerns, provide clarity, and answer questions about the Project. Indigenous groups are interested in the potential effects of the Phase 2 project on the environment and on the exercise of Indigenous rights, as they would be with any industrial development. Accordingly, at this time, the concerns expressed by Indigenous groups do not have a significant impact to either the timing of or economics of the business case for the TLSE project.