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March 4, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599170

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

Response to the British Columbia Utilities Commission (BCUC) Panel Information Request (IR) No. 1

On December 29, 2020, FEI filed the Application referenced above. In accordance with the amended regulatory timetable established in Order G-58-22 for the review of the Application, FEI respectfully submits the attached response to BCUC Panel IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

1.0 Exhibit B-21, BCUC IR 81.1, 83.2

Future Changes in Gas Supply

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 81.1, FortisBC Energy Inc. (FEI) stated:

> There are several developments affecting the Lower Mainland region that could change natural gas use over time; however, those changes also increase the use of renewable and low carbon energy, such as RNG [renewable natural gas], which FEI expects to be an integral part of BC's clean energy future. Policies such as the Province's plan to cap greenhouse gas emissions from gas utility customers, or the transition of new buildings to zero emissions by 2030, are expected to result in less conventional natural gas use in the residential, commercial, and industrial sectors. However, FEI expects the continued development and expansion of renewable gas supply, such as RNG and hydrogen, will offset this impact.
>
> …
>
> To avoid the future uncertainties that will affect future peak demand, FEI believes sizing the TLSE [Tilbury Liquefied Natural Gas Storage] Project based on the 2019/20 design load forecast remains appropriate. Finally, the risk associated with the peak demand declining over time can be mitigated through the flexibility of FEI's contracted assets (i.e., off system storage at JPS or Mist). In particular, FEI's storage profile typically has contracts expiring once every three years. If the load duration curve changes over time (such that less supply is needed from the TLSE assets), FEI has the ability to de-contract a portion of its off-system storage resources.

In response to BCUC IR 83.2, FEI stated:

> FEI is enabled under the amended GGRR [Greenhouse Gas Reduction (Clean Energy Regulation] to acquire hydrogen to meet near term objectives including:
>
> …
>
> • Purchasing hydrogen that could be distributed through dedicated infrastructure (new or repurposed) to gas customers to displace conventional natural gas usage.
>
> …
>
> Over the longer term (assumed between 2030 and 2050), as demand for hydrogen grows, the existing gas system high pressure transmission pipeline corridors would be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and (bio)methane in a progressively decarbonized gas system.

1.1 Please provide a range of forecast scenarios for firm peak demand in the Lower Mainland (LML) in 2030 and 2050, which at a minimum outline a high, reference and low demand forecast. For each scenario, please explain:

a. The key assumptions underpinning the forecast scenario;

b. The volume of the proposed tank and regasification capacity that would need to be reserved for resiliency purposes.

Response:

FEI's long-term forecast of peak demand is based on a 20-year planning horizon consistent with the 2022 Long Term Gas Resource Plan (LTGRP) to be submitted to the BCUC at the end of March.

FEI's response to BCUC Panel IR1 1.2 also provides important context and background and should be read in conjunction with this response. Over the next 20 years and beyond, FEI's infrastructure needs to support multiple objectives, including:

- a transition to renewable and low carbon gas that includes methane, hydrogen, and smaller amounts of other resources;
- continuing to support the energy transition through delivery of conventional and renewable sources of methane supplies;
- maintaining and improving system resiliency to serve the need of customers and to reduce supply risk; and
- enabling innovative new energy solutions upstream, on-system, and near the end use to help reduce BC and global carbon emissions and to realize other benefits.

Over the timeframe from 2030 to 2050, the vast majority of energy molecules delivered by FEI's system will be methane, bio-methane and hydrogen. FEI's response to BCUC Panel IR1 1.2 discusses this transition further, indicating that the mix of these energy resources delivered to customers will change over time. FEI fully expects this mix to fall within a range of combinations of the various gas resources and that the expected range requires the TLSE Project to provide resiliency for the system throughout the LTGRP planning horizon and beyond. While the percentage of hydrogen delivered to customers on FEI's infrastructure will grow in the future, the resiliency benefits of the TLSE Project are upheld with on-system hydrogen mixes.

Forecast Descriptions and Assumptions

The rest of this response models a particular mix of methane, bio-methane and hydrogen over time that provides a conservative outlook on the need for the TLSE Project within this dynamic future. The derivation of the following forecasts developed in order to provide this response is explained in the paragraphs below:

- Traditional Peak forecast (used as the reference case in this response);
- High forecast – Traditional Peak forecast plus 10 percent;
- Low forecast – Traditional Peak forecast minus 25 percent; and
- Peak end use demand forecast (hypothetical low peak forecast based on exploratory peak demand method being examined in FEI's 2022 LTGRP)[1].

The above-noted **Traditional**, **High** and **Low** peak demand forecasts are associated with the **2022 LTGRP Diversified Energy Future scenario**; FEI uses the Diversified Energy Future scenario as its planning scenario.[2] Key planning assumptions underpinning the Diversified Energy Future scenario build upon a diversified approach to energy delivery and emissions reductions to British Columbians. Under this scenario, customer growth occurs for both the electric and gas utilities and growth in the use of natural and renewable gas as a transportation fuel is larger in the Lower Mainland than in other regions of the Province, particularly in the marine transportation sector. For the analysis requested in this information request, the total Diversified Energy Future scenario demand for the CTS has been adjusted to reflect only the customer demand in the Lower Mainland that would be supported by the TLSE Project under peak conditions that would be affected by a significant supply disruption. The peak demand for these firm customers is 865 MMcf/day in the winter of 2019-2020. Also for this analysis, FEI has not included system demand from Woodfibre LNG (WLNG) of 95 PJ annually in the calculations shown since the TLSE Project is neither designed nor intended to support WLNG demand, and WLNG demand is considered a flow-through load rather than an end-use for the purpose of assessing GHG emissions.

The **Traditional Peak Forecast** method is based on current customer peak consumption per account and future account forecasts and as such represents a "reference case" as it reflects the continuation of current system use; FEI uses this method today to plan for future infrastructure upgrades.

[1] In its 2022 LTGRP, FEI explores a potential alternative method for forecasting peak demand using end-use energy equipment information derived from FEI's long term end-use annual demand forecast results. This method remains hypothetical because empirical evidence linking changes to energy equipment and customer behavior to reductions in peak demand has not been identified but merits further investigation. Since this hypothetical or exploratory method results in a lower peak demand than the method FEI employs, FEI believes including it in this analysis offers a conservatively broad spectrum of peak demand forecasts with which to prepare this response.

[2] In the 2022 LTGRP, the Reference Case annual demand scenario is based on a future that is a continuation of current conditions at the time future scenarios were established (2020). As such, it does not include the actions that FEI needs to take, or anticipates will occur, in order to decarbonize energy supplies on behalf of customers. For this reason the Reference Case is not selected as FEI's long-term planning scenario. Instead, FEI uses the Diversified Energy Future scenario which uses the existing gas infrastructure to deliver low carbon energy solutions to customers as its planning scenario. The LTGRP also examines a number of other substantially different future scenarios which demonstrate that the Diversified Energy Future is the appropriate scenario to plan for.

FEI's forecasts currently extend to 2042 in the LTGRP. Therefore, FEI has extrapolated the above forecasts to 2050 by calculating the average peak growth in the forecast in the five-year period from 2038 to 2042 and applying that growth to the eight-year period from 2043 to 2050. This is a reasonable means of projecting the observed trajectory of the forecast in the absence of more detailed information.

In the TLSE Application, FEI uses units of volume (e.g., MMcf or Bcf) as measurements of peak demand as they are the most relevant to the proposed tank and increased regasification capacity. However, representing energy in standard volumes such as MMcf is inadequate to compare peak demand in future years where a portion of the demand will be supported by hydrogen. This is because hydrogen has approximately one-third the energy content of natural gas or renewable natural gas (RNG) per unit volume. Therefore, the tables below present much of the information in TJ/day rather than MMcf/day. The base year demand of 865 MMcf/day is represented in the tables as equivalent to 950 TJ/day. When appropriate, FEI has converted demand back to MMcf/day so that the results can be compared easily to the peak demand of 865 MMcf/day and regasification capacity of 800 MMcf/day presented in the Application. In the tables below, FEI has separated the peak demand associated with the future hydrogen system.

In preparing this response, FEI assumed that end-use gas equipment will evolve to be able to utilize hydrogen gas along different potential paths. Today, end-use equipment is assumed to be able to burn a blended mix of methane and low concentrations of hydrogen. The scenarios presented assume that equipment will evolve to 1) be able to utilize higher concentrations of hydrogen mixed with methane and 2) some gas equipment (industrial process equipment for example) could evolve to be able to fuel switch between hydrogen and methane and some customers may choose to install equipment that will be hydrogen dedicated. FEI assumes in these scenarios that all of these types of equipment except equipment that is solely dedicated to utilizing hydrogen will be able to benefit from the resiliency provided by the TLSE Project. The eventual mix of these types of equipment throughout FEI's service territory is yet to be determined. Therefore, in order to examine the implications of these alternatives on the need for and benefits of the TLSE Project, FEI has modelled this changing mix in two ways (as further illustrated in the tables below):

- Scenario A - FEI assumes that equipment is dedicated to using only hydrogen as a fuel, that none of the hydrogen used in the system is blended with natural gas and RNG, that a concentration of 100 percent hydrogen is provided to consumers, and that the TLSE Project may not be able to support the peak demand for this portion of the demand.
- Scenario B - FEI assumes that the equipment can use a varying blend of methane and hydrogen or can fuel switch between the two fuels, that about 50 percent of the hydrogen that is used in the CTS is blended with the natural gas and RNG and delivered to consumers. As such, methane/bio-methane from the TLSE Project can displace 50 percent of the on-system hydrogen during peak events.

While the planning for hydrogen is evolving in industry, and the ultimate mix is unknown, FEI expects Scenario B to be in the range of a more realistic outcome in the future because it demonstrates the compatibility of methane fuels with hydrogen within the network. However, Scenario A is useful to show a very conservative assumption for TLSE tank volume and regasification capacity.

Scenarios Demonstrate the Appropriateness of TLSE Tank Volume and Regasification

The following analysis will demonstrate the appropriateness of the TLSE tank volume and regasification capacity in the vast majority of scenarios in 2030, 2042, and 2050.

2030 Forecasts

FEI anticipates that in 2030 on an annual basis FEI will be providing approximately 24 percent[3] of its projected annual demand in the form of renewable and low carbon gases consisting of hydrogen and RNG, along with some syngas/lignin and some carbon capture and sequestration (CCS).

Approximately 50 to 55 percent of renewable and low carbon gases will be on-system and 45 to 50 percent will be supplied and consumed outside of FEI's service territory (as further explained in the response to BCUC Panel IR1 1.2). In the CTS, the hydrogen will be delivered via dedicated systems and blended into downstream distribution systems in larger volumes.

Accordingly, by 2030 in the Lower Mainland, FEI projects that approximately 3 to 4 percent of the demand would be served by hydrogen. Consequently, 96 to 97 percent of the peak demand in 2030 is expected to be provided by natural gas or RNG that is able to be supported by the TLSE Project storage and regasification in the event of a supply disruption.[4]

Table 1 below details the projected peak demand for the four forecasts in 2030. The second column from the right shows the send out requirement to support the natural gas and RNG demand (in MMcf/day) after subtracting the portion of the system demand supported by hydrogen.

The table demonstrates that:

- ***Regasification capacity (2030):*** The values are all very near or over the capacity of the 800 MMcf/day regasification, indicating that in all forecast scenarios the proposed regasification is needed on a peak day in 2030.
- ***Tank volume (2030):*** The last column shows the volume (in Bcf) of LNG storage required over the coldest three days of a design year in 2030. The forecast requirement for LNG inventory ranges from 2.1 to 2.4 Bcf.[5]

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[3] 24 percent represents the renewable and low carbon gas required to meet Provincial emission reduction targets for the residential, commercial and industrial sectors and accounts for load growth from the use of natural gas and RNG as a transportation fuel, which also reduces carbon emissions in BC and globally.

[4] Natural gas and RNG used to produce LNG at Tilbury is removed from the percentages and peak demand presented in the table as this demand is curtailed when the TLSE send out would be required.

[5] As the proposed regasification capacity of the TLSE Project is 800 MMcf/day the volume able to be delivered each day is limited to 800 MMcf/day even on days where the peak demand may exceed 800 MMcf/day. The difference

Table 1

Diversified Energy Future Peak Demand Forecasts	2019	2030							
				Scenario A			Scenario B		
	Base Year Peak demand (TJ/day)	Total Peak Demand (TJ/day)	Hydrogen (TJ/day)	NG and RNG (TJ/day)	NG and RNG (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)	NG, RNG & H2 (TJ/day)	NG, RNG & H2 (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)
High (Traditional peak+10%)	950	1104	40.8	1063	**968**	**2.40**	1084	**987**	**2.40**
Traditional Peak	950	1048	38.8	1009	**919**	**2.37**	1029	**937**	**2.39**
Low (Traditional Peak-25%)	950	910	33.7	876	**798**	**2.20**	893	**813**	**2.26**
End Use Peak (theoretical method)	950	891	33.0	858	**781**	**2.11**	875	**796**	**2.19**

950 TJ/day is 865 MMcf/day

2042 Forecasts

FEI anticipates that in 2042 on an annual basis FEI will be providing just over 43 percent[6] of the projected annual demand as renewable or low carbon gases. Approximately 80 percent will be on-system and 20 percent will be supplied and consumed outside of FEI's service territory. In the CTS, the hydrogen will be delivered in dedicated systems and blended into the distribution systems in larger volumes.

By 2042 in the Lower Mainland, FEI expects that approximately 20 to 25 percent of the forecast peak demand would be served by hydrogen. The remaining 75 to 80 percent of the peak demand in 2042 will be provided by natural gas or RNG that could be supported by the TLSE Project storage and regasification.

Table 2 below details the projected peak demand for the four forecasts for 2042. This table demonstrates that:

- ***Regasification capacity (2042)***: The send-out requirements in the second column from the right show that after subtracting the portion of the system demand served by on-system hydrogen, the high, traditional, and low forecasts still require more than 600 MMcf/day of send-out. As such, the proposed regasification capacity would still be required in 2042 in each of the forecasts. Further, even using the theoretical end-use peak forecast method, 600 MMcf/day will be required to serve a peak day in the Lower Mainland until approximately 2038 in the lowest end-use peak forecast.
- ***Tank volume (2042)***: The last column shows the range of forecasts for the volume of LNG storage that would be required over the coldest three days of a design year in 2042. The forecast requirement for LNG inventory ranges from 1.6 to 2.4 Bcf. In all cases, the proposed TLSE tank sizing remains appropriate.

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would need to be provided by curtailing the excess firm demand present in those future forecast scenarios.

[6] 43 percent represents the renewable and low carbon gas required to meet Provincial emission reduction targets for the residential, commercial and industrial sectors by 2050, interpolated to 2042, and accounts for load growth from use of natural gas and renewable/low carbon gas as a transportation fuel which also reduces carbon emissions in BC and globally.

Table 2

Diversified Energy Future Peak Demand Forecasts	2019	2042							
				Scenario A			Scenario B		
	Base Year Peak demand (TJ/day)	Total Peak Demand (TJ/day)	Hydrogen (TJ/day)	NG and RNG (TJ/day)	NG and RNG (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)	NG, RNG & H2 (TJ/day)	NG, RNG & H2 (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)
High (Traditional peak+10%)	950	1271	284.7	986	**898**	**2.39**	1129	**1028**	**2.40**
Traditional Peak	950	1156	258.9	897	**817**	**2.26**	1027	**935**	**2.40**
Low (Traditional Peak-25%)	950	867	194.2	673	**613**	**1.71**	770	**701**	**1.96**
End Use Peak (theoretical method)	950	794	177.9	616	**561**	**1.57**	705	**642**	**1.79**

950 TJ/day is 865 MMcf/day

2050 Forecasts

Based on an extrapolation of the 2042 forecasts, FEI anticipates that by 2050 on an annual basis it will be providing just under 60 percent[7] of the projected annual demand as renewable or low carbon gases. For this analysis, FEI assumes that 86 percent of this supply will be on-system and 14 percent will be supplied and consumed outside of FEI's service territory. In the CTS, the hydrogen will likely be primarily delivered in dedicated systems and blended into the distribution systems.

By 2050 in the Lower Mainland, FEI expects that approximately 35 percent of the forecast peak demand would be served by hydrogen. The remaining 65 percent of the peak demand in 2050 will be provided by natural gas or RNG that could be supported by the TLSE Project storage and regasification.

Table 3 below details the projected peak demand for the four forecasts for 2050. The table demonstrates:

- ***Regasification capacity (2050):*** The send-out requirements in the second column from the right show that, after subtracting the portion of the system demand supported by on-system hydrogen, the high and traditional peak forecasts still require more than 600 MMcf/day of send-out; thus the proposed regasification capacity would still be required in 2050 in these forecasts. The two lower forecasts may not require the full 800 MMcf/day vaporizer capacity at that time, but as indicated previously this capacity will be needed until 2038 to 2042.
- ***Tank volume (2050):*** The last column shows the range of forecasts for the volume of LNG storage that would be required over the coldest three days of a design year in 2050. The forecast requirement for LNG storage ranges from 1.2 to 2.4 Bcf. In all cases, the proposed TLSE tank storage remains appropriate.

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7 Since FEI has not prepared a forecast to 2050, this value is based on an extrapolation of the LTGRP 20-year forecast to 2050. 60 percent represents the approximate renewable and low carbon gas required to meet Provincial emission reduction targets of 80 percent for the residential, commercial and industrial sectors and accounts for load growth from use of natural gas and renewable/low carbon gas as a transportation fuel which also reduces carbon emissions in BC and globally.

Table 3

Diversified Energy Future Peak Demand Forecasts	2019	2050							
				Scenario A			Scenario B		
	Base Year Peak demand (TJ/day)	Total Peak Demand (TJ/day)	Hydrogen (TJ/day)	NG and RNG (TJ/day)	NG and RNG (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)	NG, RNG & H2 (TJ/day)	NG, RNG & H2 (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)
High (Traditional peak+10%)	950	1383	481.3	902	**821**	**2.27**	1142	**1040**	**2.40**
Traditional Peak	950	1230	428.0	802	**730**	**2.04**	1016	**925**	**2.40**
Low (Traditional Peak-25%)	950	838	291.6	546	**497**	**1.39**	692	**630**	**1.76**
End Use Peak (theoretical method)	950	738	256.8	481	**438**	**1.22**	610	**555**	**1.55**

950 TJ/day is 865 MMcf/day

Forecast Scenarios Support Project Need

FEI's forecast information above for a diversified energy future strongly supports a tank size of at least 2 Bcf (consistent with its analysis in Section 4.3.5.3 of the Application) and regasification capacity of 800 MMcf/day (consistent with its analysis in Section 4.4.2 of the Application) to meet the Minimum Resiliency Planning Objective. In particular:

- ***Tank volume:*** In all forecast scenarios, more than 2 Bcf is still required beyond 2030 to support demand on the coldest three days. In 2050, the Low (Traditional Peak forecast minus 25 percent) forecast volume remains close to 2 Bcf in scenario B, and even the theoretical end use peak forecast volume is above 1.2 Bcf.
- ***Regasification capacity:*** The forecasts also show that more than 600 MMcf/day of send-out would be needed until at least 2042 in all but the theoretical end-use forecast. This indicates the proposed 800 MMcf/day of regasification capacity is sized appropriately to meet forecast need until at least 2042. By 2050, both the traditional peak forecast and the high forecast support FEI's proposed 800 MMcf/day regasification sizing in order to meet the Minimum Resiliency Planning Objective.

1.2 Please discuss the expected resource mix (e.g. conventional natural gas, renewable natural gas, hydrogen etc.) that FEI anticipates would serve customers in the LML while meeting provincial greenhouse gas (GHG) targets in 2030 and 2050. Please also discuss the extent to which the resource mix may change in a higher or lower load scenario.

Response:

As discussed in the response to BCUC IR2 80.1.2, FEI's framework to transition to a low carbon energy future is the Clean Growth Pathway to 2050. The Clean Growth Pathway is a diversified approach that is technology agnostic. At this point in the energy transition it is important to maximize the number of decarbonization pathways available and explore business models that meet energy demands and maximize the use of existing assets, thereby avoiding the costs that would come with the complete re-engineering of BC's energy sector. In the 2022 LTGRP, the Clean Growth Pathway to 2050 is represented by the Diversified Energy Future scenario.

With this in mind, FEI is planning for gas supply resources made up of increasing amounts of renewable and low carbon gas over the next 20 years and beyond. The components of this resource mix are expected to include renewable natural gas (RNG), hydrogen (H2), natural gas, and smaller amounts of syngas and lignin, supplemented later in the planning period by carbon capture, utilization or sequestration (CCUS). The amount of each resource to be acquired and delivered to customers throughout the planning period will ultimately be predicated on a number of a variables, including:

- **Quantity and Timing of Resource Availability**: Although FEI has modelled the mix of renewable and low carbon gases in certain proportions over time in the LTGRP planning scenario, the actual amount of each component that is acquired and delivered to customers could vary from the modelled amounts over the planning horizon based on a number of factors, including resource costs and supply project opportunities and development. Renewable and low-carbon gases with the highest volume potential over the planning horizon are RNG and H2. In particular, RNG is interchangeable[8] with natural gas and has wider availability so will make up a greater proportion of the resource mix in the near term. RNG will continue to be a large part of the resource mix throughout the planning horizon and beyond. While H2 resource development is underway, it is expected to become more widely available and make up an increasing proportion of the resource mix later in the planning horizon beyond 2030.
- **Resource Development and Delivery:** Many pathways exist for bringing the benefits of renewable and low carbon gas to FEI's customers; however, there are a number of ways in which these resources can be developed and delivered to customers which will ultimately impact the overall resource mix. For example, one means of incorporating more renewable and low carbon gas into the resource mix is through acquiring off-system supply, wherein FEI acquires renewable and low carbon gases in other regions and transports the gas by displacement to its system. While this process ultimately displaces conventional natural gas molecules, FEI customers physically receive conventional natural gas along with the environmental attributes associated with renewable and low carbon gas through displacement. The incorporation of these types of off-system supply will play an important role over the planning horizon as more on- or near-system resources are developed. FEI has also identified a number of ways to develop H2 supplies. These include, but are not limited to:
    - locating H2 production facilities that use RNG and natural gas as a feedstock near the end use;
    - blending H2 from physical production facilities on-system or upstream with natural gas on existing pipelines; and

[8] The physical properties of renewable natural gas, such as, specific gravity, viscosity and heating value, etc., falls with the range of the physical properties of FEI's conventional sources of natural gas. The capacity impacts and gas supply resource needs are comparable, and both sources of methane can utilize the same upstream and on-system infrastructure.

    - developing dedicated delivery infrastructure over the longer term.

- **Location:** Given the length of the planning horizon, the geographic location where renewable and low carbon supply production is physically delivered to FEI's customers is not yet known in detail. Production facilities for RNG and H2 supplies are expected to be developed both on FEI's system and, over time, in locations where these low carbon gases can be injected into the existing upstream gas infrastructure. While many potential projects are in the concept and development stages, the location of all those that will proceed during the next 20 years is uncertain. In particular, the extent to which such resources are developed and delivered to customers on one portion of FEI's system will impact the amount of RNG and natural gas that will still need to be delivered on other portions of the system over the planning horizon.

FEI will discuss these resources and the range of quantities, timing of availability, modes of development and delivery and production location in greater detail as part of its 2022 LTGRP. However, as discussed in the response to BCUC Panel IR1 1.1, throughout the energy transition over the next 20 years and beyond to 2050, methane (both renewable and conventional natural gas) will continue to play a significant role in providing firm energy service to customers in the Lower Mainland. Therefore, the TLSE Project will be required to support the resilience of methane-based energy deliveries to customers well into the future.

FEI's modelling of supply resources over the next 20 years provides the following observations regarding supply resource mix in the future for FEI's 2022 LTGRP planning scenario. These observations apply to a moderate range of higher or lower demand forecasts. Note that the 2022 LTGRP modelling only extends to 2042; therefore, scenarios extending to 2050 are based on the trends regarding resource mix observed at the end of the LTGRP planning horizon, informed by the results of the Guidehouse report on *Pathways for British Columbia to Achieve its GHG Reduction Goals*[9] which considers a longer planning horizon. Table 1 below sets out the anticipated gas supply resource mix observations for annual and peak demand for the 2022 LTGRP Diversified Energy Future (Planning) Scenario over the planning horizon and to 2050. Below the table, FEI provides its observations on resource mixes under high and low demand scenarios as well.

[9] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf?sfvrsn=dbb70958_0.

1 **Table 1**

Year	Resource Mix Observations: Annual	Resource Mix Observations: Peak
2030	Off-system supplies of RNG and H2 will be relied on in the early stages of FEI's carbon reduction transition. Natural gas and RNG will continue to make up the majority of physical deliveries to customers during this period. For off-system supplies, carbon reductions are achieved through the displacement of conventional gas in favor of renewable and low carbon purchases. By way of displacement, FEI customers physically receive conventional gas in addition to the environmental attributes associated with the renewable and low carbon gas purchased in other jurisdictions. Physical flows of H2 on FEI's gas infrastructure are expected to be limited to smaller amounts and portions of FEI's system until around 2030 as the technologies and infrastructure needed to manage larger volumes are refined and implemented. One or more syngas and lignin projects will displace some industrial load, though natural gas may continue to provide firm back-up service for periods when syngas/lignin production is unavailable. CCUS is expected to still be in development stages, perhaps available in small amounts through pilot projects, in 2030.	The majority of FEI's firm customers, including those in the Lower Mainland, will continue to be using methane for space and water heating. Natural gas will provide firming service to on-system RNG resources during peak periods. As such, peak requirements for deliveries of methane molecules are expected to change little by 2030.
2042	This is the end of the planning horizon for the 2022 LTGRP and as such is subject to greater uncertainty with regard to the range of factors discussed above. The proportion of FEI customers using methane for space and water heating as opposed to other renewable and low carbon gas supplies will have decreased, but will still make up a majority of customers. While the development of on-system resources will have grown in the intervening years, FEI anticipates there will still be reliance on off-system supplies, and therefore, the need to flow physical molecules of RNG and natural gas to a majority of FEI's customers.	As a majority of FEI customers will still be using methane for space and water heating as opposed to other renewable and low carbon gas supplies, a large requirement for methane peaking services will remain. To the extent that a portion of customers have switched completely to H2 service, the TLSE Project will be able to provide resiliency benefits to the remaining "methane customers" over a longer period of time (i.e., a longer cold snap or potential pipeline outage).

Year	Resource Mix Observations	
	Annual	Peak
2050	The steps taken early in the planning horizon have set FEI on a pathway to deep decarbonization by 2050 and well on its way to carbon neutrality on an annual basis. RNG and H2 will both be an important part of FEI's resource mix.	A large portion of FEI's demand continues to be met via delivery of methane to customers and delivery of methane to H2 production facilities. As such, the resiliency benefits of the TLSE Project remain important, particularly as extreme weather events continue into the future.

Resource Mix Under Higher or Lower Demand Scenarios

FEI expects the mix of supply resources described in the table above to apply to a moderate range of possible higher or lower demand forecasts based on a diversified energy future, namely one in which both the electric and gas infrastructure systems are relied on to decarbonize BC's energy infrastructure.

If, however, substantially different futures unfolded, a different resource mix could also unfold. FEI anticipates that if a substantially higher demand scenario began to occur within the planning horizon, higher growth in demand for RNG and natural gas would ensue, creating greater dependence on the TLSE facility to provide resiliency for the system. In contrast, if a substantially lower demand scenario began to unfold such as deep electrification and a lack of support for renewable and low carbon gas development, FEI anticipates that unintended consequences to the electricity system would begin to emerge, creating at best an uncertain future for the reliability and performance of BC's energy infrastructure overall. Under such circumstances, the resiliency of BC's energy infrastructure could be expected to become strained, requiring costly and reactive responses.

1.2.1 Please discuss the extent to which FEI's reliance on the T-South system for supply would be expected to change compared to today based upon the expected resources supplied in the LML in 2030 and 2050. Where possible, please provide a quantitative estimate of the change in reliance on T-South.

1.2.1.1 If FEI's future reliance on T-South for LML supply were to reduce in future, please discuss how this would change FEI's utilization of the TLSE Project for resiliency purposes.

Response:

As discussed in the response to BCUC IR2 81.1, and further described in the response to BCUC Panel IR1 1.2, the existing upstream infrastructure that FEI relies on for gas supply will continue to be an integral part of BC's clean energy future. Although there will be a significant amount of RNG incorporated into FEI's resource mix by 2030, the majority of this supply will be acquired outside of FEI's service territory (i.e., off-system) and received at the AECO/NIT or Station 2 hubs by way of displacement. Therefore, FEI will still require the same level of contracted third-party pipeline infrastructure such as T-South to deliver gas (whether conventional or renewable) to FEI's Lower Mainland load centre.

Between 2030 and 2050, FEI expects additional low carbon energy supply projects, such as those that produce hydrogen for use in place of natural gas, to be incorporated into the resource mix. Although there is still uncertainty as to what the impact will be to each of FEI's service regions, many of these projects will continue to utilize the upstream infrastructure in a significant way. For instance, while the appropriate amounts are yet to be determined, there is a major opportunity to inject hydrogen into the gas supply to create a blended product within the existing upstream gas infrastructure. Therefore, until new pipeline infrastructure is added into the region, FEI will continue to rely heavily on the T-South system for energy delivery into the Lower Mainland and the Interior.

While FEI expects its reliance on the T-South system to continue in the absence of new pipeline infrastructure, it is difficult to precisely quantify the extent of such reliance between 2030 and 2050. In particular, there are a number factors that impact the optimal amount of available T-South capacity. For example, in the responses to BCUC Panel IR1 1.1 and 1.2, FEI discusses the resource mix in the Lower Mainland from a peak and annual demand perspective. However, the T-South pipeline supplies gas to all FEI service regions, and this capacity is required throughout the 151-day winter heating season (November to March). As such, the optimal T-South capacity is closely tied to the winter design load duration forecasted over those 151 days. Further, the appropriate level of contracted T-South capacity also depends on market conditions in the region, as detailed in Section 3.4 of Appendix C (ACP Compliance Report) and in the response to BCUC IR1 46.1.

To manage regional market risks, FEI has held T-South pipeline capacity above its existing Lower Mainland customer load forecast as a contingency resource since 2014. Until new infrastructure is developed, FEI does not expect market conditions to change in the region, but will evaluate the appropriate amount of T-South capacity as a contingency resource over time. The only foreseeable development that would have a material impact on reducing FEI's reliance on the T-South system would be FEI's proposed Regional Gas Supply Diversity (RGSD) solution. This solution will serve not only potential load growth in the region (please also refer to the response to BCUC IR2 80.1.1), but create a flow path separate from the T-South system, thus providing much needed pipeline diversity for FEI and the region. Further, as noted in the response to BCUC IR2 80.1.2, the RGSD solution will also be a critical component in FEI's de-carbonization strategy. Given that the project will be built to be "hydrogen ready", it will enable greater capture and access to cost-effective supplies of hydrogen, enhancing the potential for GHG emission reductions in the long-term. Ultimately, a quantitative estimate of the reduced reliance on the T-South system would depend on the final sizing of the RGSD project; however, in order to maximize FEI's resiliency, the optimal amount would be to contract at least half of its T-South holdings to the Lower Mainland on the RGSD pipeline. This was discussed in Section 4.3.4.5.1 of the Application.

Finally, the use of the TLSE Project for resiliency purposes would not be impacted if FEI's future reliance on T-South for the Lower Mainland was reduced in the future. As explained in Section 4.3.1.1 of the Application, FEI's efficient gas supply portfolio requires pipeline capacity to cover different demand characteristics (i.e., baseload and longer-term seasonal demand) than FEI's on-system storage (shorter-term peak demand). Also, as discussed in the response to BCUC Panel IR1 1.2.1, FEI's reliance on T-South would only be reduced if a new pipeline was built along a different corridor. Section 4.3.4.5.1 of the Application explains how the utilization of the TLSE Project for resiliency purposes would not be materially impacted if a new regional pipeline were to be constructed.

1.2.2 Please outline any technical implications for LNG storage associated with the expected future resource mix.

<u>Response:</u>

The feedstock entering the Tilbury facility in the future is expected to differ from the present natural gas supply by incorporating increasing amounts of RNG (including biomethane) and hydrogen. RNG is interchangeable with conventional natural gas, and can be liquefied and stored at the Tilbury facility. A minor difference between these resources is that RNG feedstock may include a slightly higher amount of biomethane generation byproducts (such as nitrogen) than is typically seen in conventional pipeline gas at present. The amount and types of byproducts is unknown at this time as it would vary according to the source of the RNG, but it is expected that these would be minor components of the overall gas stream. If the predicted amount of these contaminants is expected to exceed allowable levels for liquefaction equipment, systems will be incorporated into the plant design to remove them ahead of the liquefaction process. These systems are not expected to materially impact the overall cost or operability of the facilities. As the contaminant mix is not yet known, only a high-level cost estimate is possible; at an AACE Class 5 estimate level of definition, the cost would be expected to represent a minor incremental increase of approximately 3 to 5 percent of the overall cost of the liquefaction facilities. Since liquefaction is not included within the scope of the TLSE Project, these incremental costs would not affect the TLSE Project cost.

Hydrogen cannot be stored within an LNG tank due to its much lower boiling temperature. Any hydrogen that enters the Tilbury facility would need to be removed prior to liquefaction, collected, and diverted to other uses rather than LNG storage. If and when the gas pipelines to which the

Tilbury facility are interconnected begin to contain significant amounts of hydrogen, FEI will need to incorporate systems to remove hydrogen from the incoming gas stream. This ability would be incorporated into future designs and retrofitted into existing equipment if necessary. These systems are not expected to materially impact the overall cost or operability of the Tilbury facilities. As sizing and the hydrogen mixture is not yet known, only a high-level cost estimate is possible; at an AACE Class 5 estimate level of definition, the cost would be expected to represent a minor incremental increase of 1.5 to 4 percent of the overall cost of the liquefaction facilities. Since liquefaction is not included within the scope of the TLSE Project, these incremental costs would not affect the TLSE Project cost.

Notwithstanding the modifications discussed above, FEI expects that the Tilbury facility will continue to play a critical role in maintaining a safe, reliable, and cost-effective gas supply (whether from conventional or renewable methane) to hundreds of thousands of Lower Mainland customers.

1.3 If not addressed above, please discuss the extent to which the proposed tank would be used and useful if FEI supplied no conventional natural gas by 2050.

Response:

In all future scenarios, FEI expects that the proposed TLSE tank will continue to be used and useful.

FEI does not foresee a scenario where it would be supplying energy with no methane component (i.e., no conventional natural gas or RNG) by 2050. As explained in the response to BCUC Panel IR1 1.1, FEI anticipates that by 2050 approximately 65 percent of the Lower Mainland peak demand will be served by methane-based energy, and therefore, the proposed TLSE tank will continue to be used and useful. Please also refer to the response to BCUC Panel IR1 1.2 for a detailed explanation of the expected future resource mix.

Further, as explained in the response to BCUC Panel IR1 1.2.2, the feedstock entering the Tilbury facility in the future is expected to include increasing amounts of RNG and hydrogen. RNG is interchangeable with conventional natural gas and can be liquefied and stored at the Tilbury facility without modification. Hydrogen, in contrast, cannot be stored within an LNG tank due to its much lower boiling temperature. However, future modifications and equipment retrofits, such as hydrogen separation equipment upstream of the liquefaction equipment, will be incorporated (if necessary) to ensure the ongoing and continuing usefulness of the proposed TLSE tank and facility. As noted in the response to BCUC Panel IR1 1.2.2, liquefaction is not included within the scope of the TLSE Project; as such, these incremental costs would not affect the TLSE Project cost.

1.4 Please discuss whether FEI considers the LML has the potential for new or repurposed dedicated hydrogen-only infrastructure.

Response:

FEI continues to advance a range of activities to study, test, and verify that hydrogen is safe to use in the existing gas system and to identify any changes that may be required to ensure ongoing safe operation of the gas system. FEI's Coastal Transmission System (CTS) pipelines in the Lower Mainland will continue to be used and useful as they are capable of safely transporting a blend of hydrogen.

The following provides background regarding blending hydrogen in pipelines and describes FEI's key ongoing activities to investigate doing so.

Hydrogen-ready pipe is well understood

Hydrogen gas has been safely stored and transported in dedicated high-pressure steel tanks and pipelines for many decades. As such, the engineering challenges are well understood. Pipelines that are considered fully hydrogen-ready have been specified, designed, and constructed from their outset to transport pure hydrogen. As such, consideration is given to materials, components, and procedures (e.g., pipeline steel, welds, gaskets/seals, valves, etc.) that are known to be able to operate in a pure hydrogen environment.[10] However, as FEI explains below, even pipe that was not designed and constructed from the outset for hydrogen service can still transport meaningful quantities of hydrogen, in some cases with little to no modifications.

Preliminary analysis shows FEI's CTS can transport a blend of hydrogen

FEI has completed preliminary analysis to understand the admissible limits for hydrogen blending for its existing natural gas infrastructure and end-use customer equipment and applications. The analysis was informed by current industry knowledge and indicates that the existing transmission pressure pipelines in the Lower Mainland can transport a blend of hydrogen and methane (i.e., conventional and renewable natural gas). This is consistent with industry experience from hydrogen blending pilot projects around the world that have consistently demonstrated that steel pipelines can accommodate low hydrogen concentrations (approximately 10 percent or less) with no negative effects.

FEI is investigating methods to mitigate risks of higher hydrogen blends

Hydrogen has different chemical properties compared to methane. The most significant concern in the context of steel pipelines is variously known as "hydrogen embrittlement" or "hydrogen-

[10] https://h2tools.org/.

induced cracking". Hydrogen gas is made up of hydrogen molecules which can dissociate into hydrogen atoms on the inside surface of steel pipe and, because hydrogen is the smallest atom, it has some propensity to adsorb into the steel lattice comprising the pipe body and welds. This can degrade the mechanical properties of the steel, and, in simple terms, can cause it to become more brittle and result in the formation or growth of cracks. This is why FEI's ongoing program of hydrogen research and development activities, including for example the data collected by FEI's proposed CTS TIMC Project and other ILI activities, will allow FEI to identify and address any cracking threats on the CTS pipelines. This work will help FEI evaluate the safe operation of the CTS pipelines under various hydrogen blending scenarios in the future. FEI is also investigating emerging industry solutions to inhibit hydrogen embrittlement, such as the presence of small quantities of oxygen. Further research and technical assessment is ongoing to analyze if the levels at which the oxygen is present would be sufficient to mitigate the risk of embrittlement if high concentrations of hydrogen were added to the CTS pipelines.

FEI is exploring future distribution of 100 percent hydrogen

The distribution of 100 percent hydrogen may be pursued by FEI in the future either through retrofitting existing infrastructure, investments in new infrastructure, or by production of hydrogen closer to the point of use. However, at this time, FEI does not know which, if any, of the segments of the CTS might need to be replaced or repurposed, nor the timing of this work.

FEI does not envision CTS pipelines being removed and replaced with new hydrogen-ready pipelines, as this would not be a cost-effective method to potentially support 100 percent hydrogen distribution. Instead, by 2030, FEI envisions that blending of hydrogen would expand across the low-pressure gas distribution system, with the potential for segments of the system around hydrogen hubs to be converted to 100 percent hydrogen. Between 2030 and 2050, as demand for hydrogen grows, FEI envisions that the existing gas system pipeline corridors would be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and (bio)methane in a progressively decarbonized gas system. Additional amounts of hydrogen to support FEI's low-carbon diversified pathway may also be transported by other new or repurposed infrastructure.

In addition to the above, please refer to FEI's responses to BCUC Panel IR1 as part of the CTS TIMC CPCN proceeding (provided as Attachment 1.4), in which FEI provides additional information on FEI's evaluations for blending hydrogen into existing infrastructure, and the need for repurposing existing pipeline segments or replacing pipeline segments for 100 percent hydrogen use.

1.4.1 Please confirm, or explain otherwise, that LNG storage would not be useful for customers served by dedicated hydrogen infrastructure.

Response:

If dedicated hydrogen delivery infrastructure is developed (i.e., a pipeline system to deliver gas with no methane component), then the Tilbury LNG storage system could not be used to feed those networks. However, if a user also takes supply from FEI's natural gas system, the Tilbury LNG storage system could be used to provide resiliency for that load in the event of a supply disruption on the dedicated hydrogen network.

Despite the premise of this question, at this time, FEI expects that methane (whether from conventional or renewable sources) will continue to exceed 80 percent by volume of the gas transported by the CTS pipelines for at least 20 years. The TLSE Project's LNG storage volumes are meant to support the resiliency of FEI's overall system in the event of a supply interruption. This resiliency benefit will be effective for the system even if it delivers a hydrogen/methane gas mixture in the future, although in this scenario where the TLSE storage tank is utilized, the proportion of hydrogen within the systems being fed from the TLSE storage would temporarily drop until the supply interruption is corrected and normal service resumes.

Please also refer to the response to BCUC Panel IR1 1.2.2.

1.5 Please provide a discussion of the expected annual cost savings associated with de-contracting a portion of FEI's off-system storage resources, in the event of a decline in FEI's peak demand.

1.5.1 Please discuss the factors that FEI considers are likely to affect the costs of off-system storage in the medium and long term.

Response:

There are a number of factors that FEI would consider before de-contracting its off-system storage resources.

First, FEI's off-system storage resources are intended to cover different demand characteristics compared to FEI's on-system storage. In Section 4.3.1.1 of the Application, and in the response to CEC IR1 46.1, FEI explains how its efficient supply portfolio strategy includes off-system storage resources to provide short- to medium-duration seasonal supply (i.e., 10 to 60 days), as well as on-system storage resources (i.e., the Tilbury and Mt. Hayes LNG facilities) which provide shorter duration supply (i.e., 1 to 10 days) to cover the winter demand peaks associated with cold weather events.

Second, FEI's off-system storage resources are generally used for daily load balancing in normal operations. As discussed in the response to the BCUC IR1 22.1, FEI's on-system LNG storage resources can help with daily balancing; however, given the smaller size of these assets, their utilization is prioritized for cold weather events and/or emergency purposes.

In the event that the future peak demand, winter load profile, and daily balancing requirements demonstrate a declining trend, FEI would evaluate the potential to de-contract a portion of its off-system storage resources (i.e., storage contracts at the Jackson Prairie and/or Mist facilities). Since the amount that could be de-contracted is subject to a number of unknown future variables, FEI has estimated the future savings using the cost of FEI's most recent off-system storage renewal and based on de-contracting 25 MMcf/day of deliverability and 1.5 Bcf of storage (i.e., 60 days of storage). Using these assumptions, the estimated annual savings would be approximately $5 to $6 million.

However, this cost savings estimate is likely conservative (low). The costs of all existing supply resources in the region (including off-system storage and pipeline capacity) are expected to increase in the medium- to long-term. For example, until new pipeline infrastructure is added, existing assets will remain fully contracted and are essential to managing winter load requirements. Therefore, if shippers need to contract additional pipeline capacity or renew off-system storage contracts, they will need to pay some premium (reflected in the forward market prices in the region) to a counterparty to obtain access to the asset. FEI provided evidence supporting this in the response to BCUC IR1 46.2. Further rationale for why these costs may increase in the medium- to long-term is as follows:

- Given the need for increased maintenance of aging third-party assets, FEI expects its costs (i.e., tolling costs and storage demand charges) will increase in the short- to medium-term; and
- Woodfibre LNG is expected to be in-service by the end of this decade.[11] If this project comes online prior to any new infrastructure, there will be supply issues in the winter for any shippers that have not contracted enough firm resources for their load requirements. Therefore, there will be higher costs associated with trying to contract additional pipeline capacity or trying to renew any off-system storage contracts.

Finally, FEI notes that any new infrastructure in the region (e.g., Westcoast T-South expansion, and/or expansions to off-system storage assets, etc.) will also come at a higher cost than existing tolls.

[11] Woodfibre LNG. (Posted on November 23, 2021). "Woodfibre LNG awards EPFC contract to McDermott."

2.0 Exhibit B-26, BCUC IR 68.2

Probability of Rupture Event

In response to BCUC IR 68.2, JANA Corporation (JANA) stated:

> Outage duration is reported for some of the PHMSA [Pipeline and Hazardous Materials Safety Administration] and TSB [Transportation Safety Board of Canada] reported rupture events. Any rupture of a 30" or 36" NPS transmission pipeline would be expected to result in an outage of at least two days duration and most likely three days or greater. Ignition events do tend to result in slightly longer outages. For PHMSA reported ruptures for pipelines 30" NPS or greater with reported outage durations, 100% had an outage duration ≥ 2 days (26 of 26) and 96% ≥ 3 days (25 of 26). For ignited ruptures, 100% of reported incidents had outage durations ≥ 3 days (20 of 20). Of the 4 TSB reported ruptures with outage durations for pipelines 30" and greater, 3 of 4 were ≥ 2 days and 2 of 4 were ≥ 3 days. For ignited ruptures, 100% of reported incidents had outage durations ≥ 2 days and 2 of 3 ≥ 3 days.

2.1 Please explain why outage duration is reported for only some rupture incidents in both the PHSMA and TSB datasets. Please discuss whether there are different reporting requirements for more severe incidents.

<u>Response:</u>

The following response was provided by JANA:

The reporting fields are the same for all reportable incidents (i.e., incidents that meet the defined reporting criteria for PHMSA and TSB). The data for both the PHMSA and TSB datasets is not complete for all reporting fields because operators do not always complete information for all the available fields.

3.0 Exhibit B-26, BCUC IR 70.2, 72.3

Controlled Shutdown

In response to BCUC IR 70.2, FEI stated:

> The TLSE Project will provide a three-day supply under peak conditions, and more time in more favourable weather conditions, providing FEI reasonable time to understand the incident, formulate a response, and then execute a controlled load-shedding strategy (if and when necessary), consistent with the factors described in the response to BCUC IR2 70.1. If system conditions necessitate that FEI complete a controlled shutdown in under three days, FEI can accelerate its shutdown plans by shutting in larger sections of the system at a time in order to meet the required timeline.

In response to BCUC IR 72.3, FEI stated:

> FEI agrees that the amount of time to make an informed decision will vary depending on a number of factors, and that three days may not be required in all instances to make an informed decision, including whether to take actions that are irreversible in the short-term (such as shutting off supply to portions of the Lower Mainland to balance available supply and demand). With the above quoted statement, FEI was intending to make the point that, in the current context where there is insufficient regasification capacity and storage in the Lower Mainland for FEI to outlast a no-flow event of any material duration, FEI is forced into making decisions and taking actions that are irreversible in the short-term almost immediately and in the absence of reliable information will not have the luxury of being able to take a measured approach to shut-down its system. Extending this decision-making interval to three days maximizes the ability for FEI to collect information, assess and evaluate the situation, consider the timeliness of repairs, curtail demand in a tailored way that minimizes overall harm, arrange alternate supply if available and determine the appropriate next steps.

3.1 During a no-flow event, please discuss the information would FEI require to make an informed decision that would lead to the initiation of a controlled shutdown.

Response:

In response to a no-flow event, FEI would collect and assess information to identify and quantify the available supply and demand requirements (as further described below). FEI's assessment would focus on determining the timing, magnitude and duration of any supply deficit and then evaluating the most effective and least impactful shutdown and curtailment options, if required (i.e., if all other supply options were exhausted). FEI would continuously monitor and update the information as the event evolves. This information would include:

Supply side information

- The cause of the no-flow event.
- The location of the supply disruption.
- The projected duration of the outage.
- The projected level of supply available on service restoration.
- The amount of useable line pack in the disrupted system accessible to FEI.
- Other pipeline supplies accessible to FEI.
- Off-system storage accessible to FEI.
- The availability, readiness, and duration of on system LNG send-out capacity.

Demand side information

- The time of year, weather/demand forecasts, and updated information regarding the projected duration of the incident.
- The available demand reduction achievable from interruptible rate schedules.
- The available demand reduction achievable from other large industrial customers.
- The potential for, and the effectiveness of, public appeals for voluntary curtailment or load management.
- The resources available (personnel and equipment) to implement a shutdown.
- A determination of the portions of the system that might be isolated to correct an identified supply/demand imbalance.
- A determination of the means of isolation and assessment of restoration.

Following the Westcoast T-South Incident in 2018, FEI filed confidentially with the BCUC with a System Preservation and Service Restoration Plan (P&R Plan). Within the P&R Plan, Appendix A – “Curtailment Decision Guidance”, provides an implementation decision checklist, including a flow chart, which builds on FEI’s established gas supply daily assessments. This process describes how FEI would act on the information collected to determine if a supply shortfall should result in a decision to curtail load as per the P&R Plan.

Recognizing that each emergency event is unique, and given that the situation will continually evolve throughout the event, FEI may initiate a shutdown process of large industrial loads relatively soon after the event begins – similar to the actions taken following the 2018 T-South Incident. The additional time provided by the TLSE Project to collect and evaluate the situation in the initial hours and days of a no-flow event will greatly improve FEI’s ability to respond more effectively in a manner that minimizes the overall impact to FEI’s customers.

3.2 If the TLSE Project was built, at what point in time during a no-flow event would FEI have to make a decision to initiate a controlled shutdown? Please assume there were no other supply resources, the no-flow event occurs during peak demand conditions, and no reliable estimate of the time to restore some gas flows on T-South is available at that time.

Response:

The scenario in the question appears to be premised on an expectation that key information about the event (including that it is, in fact, a no-flow event) will be clear soon after the initiating event. In practice, FEI expects that key information regarding a no-flow event will initially be incomplete, inconsistent, or unavailable. Therefore, the decision to initiate a controlled shutdown is not necessarily known to be inevitable at this early stage. In particular, FEI expects to require a significant portion of the first full day following a given event to evaluate and verify its significance and the potential outcomes.

In the initial hours of its response, FEI would likely shed interruptible customers and <u>prepare for</u> the potential to shutdown any quickly available firm industrial load as well as larger portions of the system; however, FEI would likely not conduct any significant system isolations early in this time period. FEI would instead likely undertake a phased shutdown sequence over the remainder of the three-day period, thereby allowing FEI to continue to assess the no-flow event and its expected duration. This approach would ensure that portions of the system survive should the circumstances of the event change favourably before the three-day period elapses.

As such, the TLSE Project will provide FEI with additional decision-making time of at least three days during peak demand, and possibly more, to collect information, assess it, and then develop and execute a controlled and strategic response.

The evolving approach described above reflects FEI's objectives when faced with the prospect of a controlled system shutdown. A key objective when initiating a controlled shutdown during a no-flow event is to maintain reliable delivery of gas to as many customers as possible until the no-flow event is resolved, while restoring some level of supply to continue to support customers that have not been isolated. Another objective is to take action where shutdowns occur in order to retain positive pressure within as much of the isolated system as possible, which enables a quicker return to service in the isolated areas.

Even if this scenario's no-flow event is so severe that gas supply to the Lower Mainland is unable to be re-established before all the LNG stored in the TLSE tank is consumed, the minimum three-day storage volume will still provide FEI with the time necessary for better decision-making in relation to the execution of a controlled shutdown of the CTS transmission pressure pipelines. In other words, in this scenario the TLSE Project will significantly improve FEI's operational response by providing the time necessary to close downstream system valves to maintain pressure in the CTS, thus allowing the system to be restored more quickly once gas supply is re-established. With the future installation of AMI (and the remotely operable shut-off valves that it will provide), FEI would also be able to shut-off customers directly at the meter set, thus assisting to maintain pressure in the distribution system (which would be beneficial in reducing the time required to re-establish service to customers and relight appliances).

Ultimately, the TLSE Project is critical in providing FEI the time necessary to gather information following a T-South no-flow event, to assess the impact of the situation, and to formulate a comprehensive plan in order to preserve service to customers on the Lower Mainland system.

3.2.1 If FEI did initiate a widespread controlled shutdown, but gas flows on T-South resumed shortly afterwards, approximately how long would it take FEI to restore service to customers?

Response:

Once gas supply to customers is shut down, the time until service is restored on the T-South system does not change or shorten the timeframe required to safely restore service to customers in the systems that were shut down. The time it would take FEI to restore service to customers following a resumption of T-South supply is dependent on the number of customers that lost gas service.

A widespread controlled shutdown in the Lower Mainland – regardless of how quickly service was restored on the T-South system – would take FEI months to restore all service (as detailed in the response to BCUC Confidential IR1 15.3). In November 2018, FEI provided the BCUC with a confidential System Preservation and Service Restoration (P&R) Plan. Page 1 of the Attachment to Appendix C of the P&R Plan provides specific detail on the time required to complete a shutdown and then re-establish service to customers in various regions of the Lower Mainland.

4.0 Exhibit B-26, BCUC IR 68.11

Project Need

In response to BCUC IR 68.11, FEI stated:

> FEI does not consider a probability analysis to be necessary to support the need for the TLSE Project, because when incidents can result in consequences that are unacceptable… a probabilistic approach is not necessary to confirm the need for mitigating actions.

4.1 Please provide examples of other projects that have been approved by the BCUC to mitigate high consequence incidents without a probabilistic approach to confirm project need.

Response:

The risk management approach that FEI is articulating for the TLSE Project has been reflected in a number of BCUC decisions related to dam safety:

- FortisBC Inc. (FBC) - Corra Linn Dam Spillway Gate Replacement Project (2017)[12]
- BC Hydro - WAC Bennett Dam Riprap Upgrade Project (2016)[13]
- BC Hydro - John Hart Generating Station Replacement Project (2013)[14]
- BC Hydro - Ruskin Dam and Powerhouse Upgrade Project (2012)[15]
- BC Hydro - Hugh Keenleyside Spillway Gates Project (2010)[16]

For clarity, FEI's statement cited in the preamble, and similar statements by experts provided in this proceeding, are not intended to convey that there is no need to determine whether an event or outcome is *possible* (in other words, whether the event can happen). Rather, it is intended to convey that, once a risk event with a *possible catastrophic outcome* has been identified, risk management principles would suggest not discounting the need to mitigate that risk simply based on the low probability of it occurring. The recommended risk management approach that applies when the consequences of a known possible risk are catastrophic differs from the more common scenario where outcomes are undesirable but still tolerable; in the latter cases (which do not include the TLSE Project), the low probability nature of the outcome can support a probability-adjusted investment to mitigate the risk.

Most capital projects brought before the BCUC to address a system risk are concerned with mitigating an undesirable outcome that, while potentially severe, is nevertheless non-catastrophic

12 https://docs.bcuc.com/Documents/Proceedings/2017/DOC_48720_C-1-17_FBC_CorraLinnDam-CPCN_reasons.pdf
13 https://docs.bcuc.com/Documents/Proceedings/2016/DOC_46419_G-78-16_BC-Hydro-Riprap-Reasons.pdf
14 https://docs.bcuc.com/Documents/Proceedings/2013/DOC_33518_C-2-13_BCH-John-Hart-Dam-WEB.pdf
15 https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111629/1/document.do
16 https://www.ordersdecisions.bcuc.com/bcuc/orders/en/117597/1/document.do

(i.e., an undesirable, but tolerable, outcome). Electric transmission systems, for example, incorporate a high degree of redundancy such that a potential failure of one aging transmission line, while not desirable, will not result in long-term loss of service to a large number of customers because other lines are available to serve those customers. Further, the utility may elect to not bring a project forward to the BCUC because the extent and duration of an outage to customers served by a radial gas or electric line may be sufficiently limited to accept the risk of a low probability event. In those instances, using a risk management approach which includes a probabilistic analysis enables the utility to calculate an investment amount that corresponds with the resulting consequence, reflecting the risk/exposure it deems to be acceptable and is willing to bear.

While investments to address undesirable, but tolerable, outcomes can be discounted based on a probabilistic analysis, dam safety projects are a notable exception and are assessed differently by the BCUC. The BCUC has accepted investments in dam safety on the basis that:

1. the initiating event *can* occur (based on a review and assessment of historical information); and
2. the resulting consequences of a failure occurring in response to an occurrence of the initiating event would be unacceptable.

As noted in the Dam Safety Review[17] for FBC's Corra Linn Dam prepared by Knight Piésold Ltd. (KP), the industry standards underlying dam safety projects are driven by an assessment of the consequences of an event, and whether or not they are tolerable. For example, in Section 5.1 of this document, KP stated:

> The Consequence Classification of a dam is based on the possible incremental consequences of dam failure i.e. the incremental consequences associated with the failure of the dam, over and above the consequences that would have been felt had the dam not failed. The possible causes of failure are broadly broken into two categories: a "sunny day" failure (i.e. one that happens without warning as, for example, with an earthquake), and a "rainy day" failure caused by floods. Consequences are separately assessed in the following categories:
>
> - Loss of human life
> - Loss or deterioration of critical fish or wildlife habitat, rare or endangered species, unique landscapes or sites of cultural significance, and
> - Economic losses affecting infrastructure, public transportation or services or commercial facilities, destruction or damage to residential areas.

[17] Appendix B of Exhibit B-1-1 in FBC's Application for a Certificate of Public Convenience and Necessity for Replacement of the Corra Linn Dam Spillway Gates Project. https://www.bcuc.com/OurWork/ViewProceeding?ApplicationId=551

> The ultimate classification is the most severe of the three categories.
>
> […]
>
> In CDSA the consequence classification dictates the required withstand capacity of the dam i.e. the higher the possible consequences the stronger the dam is required to be. This can lead to some iteration until the consequence category and the withstand capacity are in accord. For example, a dam might initially be classified Very High based on a first assessment of the consequences of dam failure. The appropriate Very High design flood is therefore used to assess downstream consequences. If the consequences prove to be greater than assumed, sufficient to reclassify the dam in the Extreme category, the exercise has to be repeated using the larger Extreme design flood which will cause greater inundation and greater consequences. [emphasis added]

In the above quote, FEI notes that the language "[…] the stronger the dam is required to be" is reflected in the use of the return period to determine the magnitude of possible extreme events (i.e., floods or seismic events). In these BCUC dam safety decisions, and in the industry standards that support those decisions, the BCUC did not make an assessment of whether or not the risk is worth simply accepting without mitigation based on the low probability of it occurring. *Put another way, there is no indication of willingness on the part of the BCUC or industry standards organizations to accept unmitigated catastrophic risk of dam failure based on a probabilistic analysis showing that the event has a low probability of occurrence*.

Further, the potential negative outcomes considered by dam safety projects are far less likely (i.e., a 1 in 10,000 year return period) relative to the design standards used for pipeline design (i.e., typically 1 in 2,475 years for modern pipelines[18]) that are applicable even today to the T-South system. The primary driver for the Corra Linn Spillway Gate Replacement Project (FBC Corra Linn Project) was that the initiating causes (a credible high-magnitude seismic or flood event) can occur and lead to a spillway gate failure. The determination of the possibility of the initiating event was reflected in the use of a 1 in 10,000 year return period (in this case, a design flood or design earthquake). A 1 in 10,000 year design event refers to an event which is so large that it would only be expected to occur once or more in a 10,000 year span. Although expressed as a mathematical fraction this calculation is best understood as a proxy for determining the size of a possible event.

In neither the FBC Corra Linn Project decision, nor any of the other dam safety project decisions listed above, did the BCUC:

- discount the need to address that catastrophic risk or the extent of allowed investment based on the low probability of it occurring; or

[18] Pipelines constructed in the 1950s (such as the Westcoast T-South NPS 30 pipeline) were likely not specified to any seismic design standard.

- reference the probability of an initiating event occurring over the useful life of the dam infrastructure.

The analysis put forward by FEI in this proceeding is very similar to the analytical framework the BCUC has applied in dam safety decisions. To illustrate this, FEI provides the comparison table below which uses the FBC Corra Linn Project for illustration, and further elaborates after the table.

	TLSE Project	Corra Linn Dam Spillway Project
What is the initiating event?	The initiating event would be a disruption on T-South, whether caused by rupture, vandalism, cyberattack or otherwise.	The initiating event would be a large flood or seismic event.
Is the initiating event possible?	FEI has identified historical incidents over the life of the T-South system where there has been a loss of gas supply, with the most significant being in 2018 that resulted in a 2 day no-flow event. JANA's white paper calculated a cumulative probability of up to 98 percent of an integrity-related rupture resulting in a T-South no-flow event over the 67-year life of the TLSE Project. FEI is unable to provide an estimate of the likelihood of vandalism or cyberattack, but each is possible.	FBC provided analysis of historical data to estimate the magnitude of design seismic or design flood events that can occur. This is reflected in the "return period" (expressed as 1 in 10,000 years), which indicates that an event of similar magnitude can be expected to occur at least once over 10,000 years (when calculated over a long period of time). There was no evidence, nor was there any discussion in the BCUC decision of the cumulative probability of the initiating event over the life of the Corra Linn dam or spillway akin to the JANA analysis. (Note: the return period is not the same as cumulative probability.)
What is the possible outcome of the initiating event?	FEI demonstrated that a T-South no-flow event which occurs during a normal winter (i.e., once every 5 years) or colder (i.e., once every 20 years) would result in a loss of gas supply to the Lower Mainland. Alternative sources of supply (e.g., off-system storage, the Mt. Hayes LNG Plant, mutual aid, etc.) are unavailable in wintertime, thus leaving the Tilbury Base Plant as the only source of supply.	Failure of spillway gates resulting in an uncontrolled release of water from the dam. The BCUC made its decision without any probability analysis to assess the likelihood that the spillway gates would fail if the initiating event was to occur.

	TLSE Project	Corra Linn Dam Spillway Project
How severe are potential consequences?	FEI provided evidence that the consequence of a winter initiating event would be catastrophic: widespread and prolonged outages affecting hundreds of thousands of customers, potentially resulting in physical harm to people, damage to property, and significant economic losses. The number of deaths in the recent Texas outages associated with cold winter weather, for instance, was well in excess of the 100 people contemplated for an "extreme" consequence dam. The PwC scenarios also provide an indication of the severity of social and economic harm from a sudden, widespread, and prolonged supply disruption during the wintertime.	FBC provided evidence that more than 100 people would be at risk if gates failed following an initiating event, given the location of premises etc., potentially resulting in physical harm to people and damage to property. This meant it qualified as an "extreme" consequence dam. The BCUC made its decision without any probability analysis to determine how many individuals would be at risk at any given time (e.g., whether premises are occupied full-time vs. at only certain times of the year or day).

As shown in the table above, a no-flow event during the winter months would result in the loss of gas service to hundreds of thousands of customers. FEI considers this outcome unacceptable given the associated impacts on customers and society – especially during periods of cold temperatures when a reliable supply of energy for thermal purposes is vital to health and safety.[19]

Corra Linn Project Decision Details

The FBC Corra Linn Project included upgrading the existing spillway gates at FBC's Corra Linn Dam, following an evaluation of the dam's consequence classification in response to a newly created classification of an "extreme" consequence dam. The approach taken in the Canadian Dam Safety Guidelines is to first consider the possible consequences of a design flood or seismic event, and then ensure that the facility is able to withstand this event. An "extreme" consequence dam is one in which failure of the dam would place more than 100 people at risk, and could result in significant impacts to customers or the public downstream of the facility.

In the Decision associated with Order C-1-17[20] approving the project, the Panel noted [footnotes omitted]:

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[19] https://www.dallasnews.com/news/weather/2021/04/30/number-of-texas-deaths-linked-to-winter-storm-grows-to-151-including-23-in-dallas-fort-worth-area/

[20] https://docs.bcuc.com/Documents/Proceedings/2017/DOC_48720_C-1-17_FBC_CorraLinnDam-CPCN_reasons.pdf

> The generally accepted industry standards for dams in Canada are set out by the Canadian Dam Association (CDA). Although the CDA is not a statutory or regulatory organization, it produces guidelines and technical bulletins on topics related to dams and sets industry standards. It produces the Canadian Dam Safety Guidelines (CDSG) which set out the generally accepted engineering practice and performance expectations for dams and has been utilized in developing the BCDSR.
>
> The CDSG sets out a Dam Consequence Classification, which is a system for classifying dams into categories, based on the severity of the possible consequences of a dam failure. Prior to 2007, the Dam Consequence Classification had a range of four classifications: “Low,” “Significant,” “High,” and “Very High.” The Dam Consequence Classification is based on the possible incremental consequences of a dam failure. The criteria for consequences include an assessment of the potential for:
>
> - loss of life;
> - loss or deterioration of critical fish or wildlife habitat, rare or endangered species, unique landscapes or sites of cultural significance; and
> - Economic losses affecting infrastructure, public transportation or services, commercial facilities or destruction or damage to residential areas.
>
> For each consequence classification, the CDSG defines a “design flood” and a “design earthquake,” which is a measure of the severity of hazards that each classification of dam is required to withstand. Design earthquake values are specific to each facility and the design flood values are specific to a particular river and the associated watershed.
>
> In 2007 the CDSG was updated to change the classification system to add an “Extreme” category and to update the “withstand capacity” for a dam with a classification of “Extreme.” FBC states that as per the CDSG recommendation “an Extreme dam and associated structures must remain stable in the event of a design flood with the maximum design flood load condition of the Probable Maximum Flood (PMF) or in the event of a design earthquake with the seismic load condition of either the 1/10,000 year event” or the Maximum Credible Earthquake (MCE). [emphasis added]

Further, in footnote 12 of the same Decision, the Panel also noted:

> The consequence classification of a dam is used to determine design criteria in the Canadian Dam Safety Guidelines and the frequency of safety activities (surveillance, inspection etc.) pursuant to Schedule 2 of the *BC Dam Safety*

> *Regulations*. Note that change in the probability of failure of a dam does not change its consequence classification. [emphasis added]

The BCUC determined that the FBC Corra Linn Project was necessary and in the public interest because extreme safety consequences could result if one or more spillway gates failed due to these initiating causes – without any assessment of the likelihood of such a gate failure occurring, or the likelihood that all 100+ individuals would be present at the time of a gate failure. As the Panel recognized: “The risks to people and property associated with either deferring or indefinitely putting off taking action on the Corra Linn spillway gates is simply too great” (p. 13).

Consequences of a T-South No-Flow Event Occurring in Winter Are an Unacceptable Outcome

In the context of the TLSE Project, the T-South Incident has shown that a no-flow event can occur on the T-South system. But for the time of year, the Lower Mainland would have experienced a widespread and prolonged load loss in 2018 as part of this no-flow event. The same event occurring in winter would have resulted in FEI being unable to survive the first day without prolonged loss of service to a significant portion of FEI’s Lower Mainland customers. As noted in the response to BCUC IR1 9.1, the magnitude of societal disruption and harm that can result if FEI does not have sufficient system resiliency to withstand a T-South no-flow event would be unprecedented in BC and could result in outcomes that are irreversible.

While the fact that the T-South Incident has already occurred recently demonstrates that it can happen, FEI retained JANA in response to IRs to assess the cumulative probability over the 67-year economic life of the TLSE Project of a rupture occurring on infrastructure of a similar quality and length based on industry statistics (no such analysis was required by the BCUC in the FBC Corra Linn Project Decision in respect of the life of the spillway gates.) As discussed in the response to BCUC IR1 1.5, JANA’s analysis determined that the cumulative probability of a rupture event is forecast to be between 83.1 to 97.9 percent, and the cumulative probability of an ignited rupture between 53.4 and 73.9 percent, over the 67-year economic life of the TLSE Project. Ruptures are just one possible cause of a no-flow event on the T-South pipeline; physical and cybersecurity sabotage are also possible.

Regardless, if a no-flow event occurs for any reason during the wintertime when FEI has no access to alternate sources of supply for the Lower Mainland load, the resulting service disruptions and impacts to hundreds of thousands of customers would be severe and unacceptable.

5.0 Exhibit B-26, BCUC 69.1

Exhibit B-28, RCIA IR 36.1.1

Advanced Metering Infrastructure (AMI)

In response to BCUC IR 69.1, FEI stated:

> FEI's proposed AMI technology will not be capable of remotely disconnecting a small group of meters within the meter fleet at this time, including a portion of the commercial meters and the industrial meters. Consequently, AMI on its own will not stop a pressure collapse from occurring in circumstances where immediate disconnection of all commercial and industrial customers from the vulnerable portion of the system is necessary to maintain sufficient pressure to avoid a collapse. Another scenario in which AMI on its own may not be able to stop a pressure collapse occurring is if the gas supply emergency is sufficiently serious that a pressure collapse will occur before AMI is able to remotely disconnect all the Lower Mainland advanced meters within one hour.

In response to Residential Consumer Intervener Association (RCIA) IR 36.1.1, FEI stated:

> FEI expects the AMI system will be capable of remotely disconnecting 600,000 advanced meters per hour. Therefore, allowing for several hours to plan and coordinate the execution of the isolation, FEI could accomplish disconnection of the Lower Mainland's advanced meters (excluding radio-off customers) within the same day. The AMI system is not capable of remotely disconnecting a portion of the commercial and all the industrial meters at this time, or advanced meters that are not connected to the AMI network (i.e., radio-off customers). In the case of some large customers, the customer has the ability to cease taking service within a few hours of receiving a curtailment order from FEI. Otherwise, FEI expects that using the available FEI resources and through direct communication with customers without AMI meters (to assist with isolations), three to four days would be adequate to disconnect all of the Lower Mainland commercial and industrial customers and any advanced meters not connected to the AMI network.

5.1 Please estimate the peak load associated with the portion of commercial meters and industrial meters that AMI will not be capable of remotely disconnecting.

<u>Response:</u>

FEI estimates that approximately 25 percent of the Lower Mainland peak load representing about 215 MMcf/day is associated with firm large commercial and industrial customers that would not be included in the remote disconnect capability of the AMI deployment. However, as explained in the response to BCUC IR1 16.1, AMI will allow FEI to monitor, in near-real time, the consumption through these commercial and industrial meters. With this information, FEI will be able to confirm that interruptible customers curtail their consumption when requested, in accordance with the obligations set out in the tariff. Moreover, FEI will be able to use this consumption information to prioritize its interactions with affected customers, and if required, manually disconnect these customers.

5.1.1 Please estimate the time that would be required to curtail all such customers.

Response:

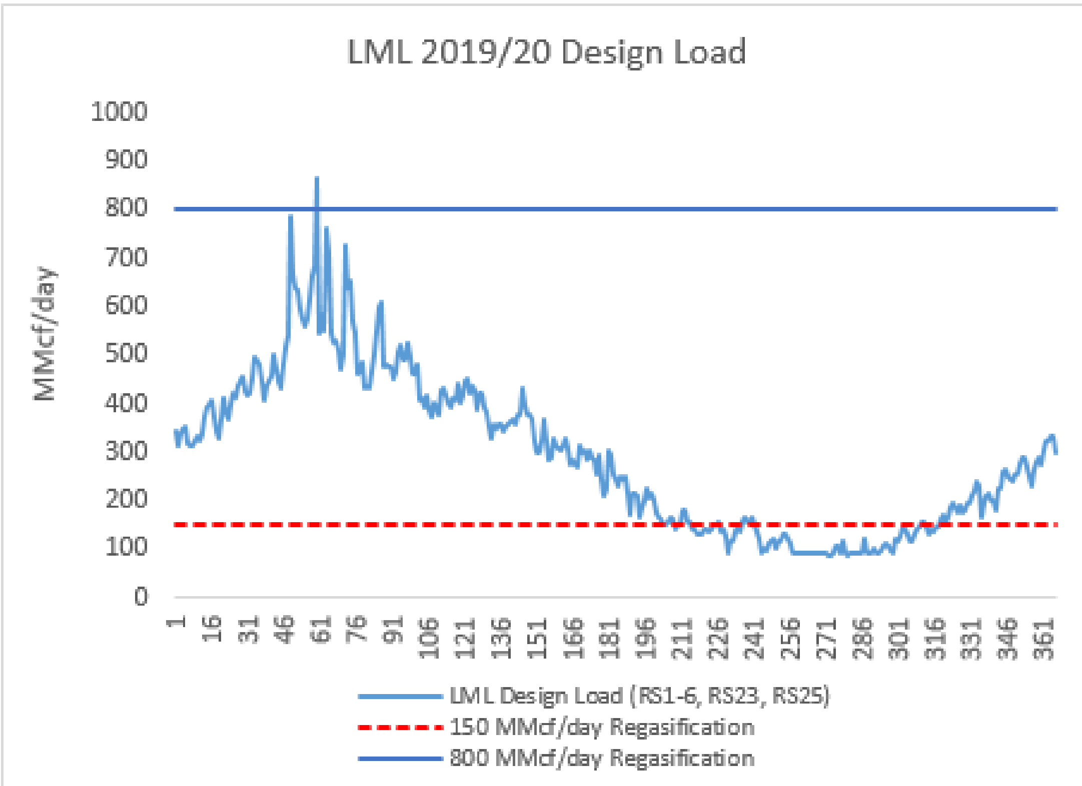
FEI confirms that the statements in the preamble cited above regarding the amount of time required to remotely disconnect all commercial meters and industrial meters that AMI will not be capable of remotely disconnecting remain accurate (i.e., "[…] three to four days would be adequate to disconnect all of the Lower Mainland commercial and industrial customers and any advanced meters not connected to the AMI network.").

5.1.2 Please discuss whether either scenario described in the response to BCUC IR 69.1 would result in a pressure collapse assuming (i) FEI has 150MMCF/day regasification, and (ii) large customers can be curtailed in the absence of AMI remote disconnection.

Response:

The figure below shows the design load duration curve for 2019/20 and compares: (1) the proposed 3 Bcf tank with 800 MMcf/day of regasification capacity; and (2) the existing Tilbury regasification capacity of 150 MMcf/day. The figure demonstrates how, for approximately 245 days in a typical year (i.e., 67 percent of the year including all but the summer months when gas usage is low), customer demand greatly exceeds the existing Tilbury send-out capability of 150 MMcf/day. During this period (which includes all of the cold winter months), if a gas supply emergency similar to that described in the response to BCUC IR2 69.1 occurs and FEI is unable to rapidly shed excess customer demand, the pipeline line pack would be quickly consumed – resulting in a pressure collapse within the Lower Mainland transmission and distribution systems. Even with significant curtailment of large customers, in the absence of AMI technology, this imbalance between the higher system demand, a rapid loss of gas supply, and the much lower send-out capability, could not be corrected quickly enough during much of the year and a pressure collapse in the Lower Mainland system would be unavoidable.

Further, irrespective of how FEI executes a rapid controlled shutdown (i.e., whether it would be done on an area-by-area basis by closing system valves, or if AMI is available, by isolating individual premises) the affected customers would experience a sudden and prolonged loss of service. AMI will shorten the time to restore service, but the outage to customers would still be lengthy.



6.0 Exhibit B-1-4 (Updated Public Application), pp. 160, 163
Exhibit B-2, Financial Model M-1, Schedule 5
Exhibit B-26, BCUC IR 91.1
Liquefied Natural Gas (LNG) Tank Depreciation

In response to BCUC IR 91.1, FEI reiterated it would record the new 3 Bcf tank under a new account with the proposed new depreciation rate of 1.67 percent and net salvage rate of 0.67 percent.

6.1 Please discuss whether FEI currently uses any other depreciation methods (i.e. non-straight line method of depreciation), to depreciate its regulated assets. As part of the response, please discuss FEI's considerations and deciding factors for using these other depreciation methods.

Response:

The following response has been prepared by Concentric.

FEI currently depreciates all assets using a straight-line method. Most assets are depreciated using the straight-line Average Service Life method, utilizing estimates for retirement dispersion (an Iowa curve), average service life, and net salvage estimate, as detailed in the Concentric depreciation study approved by the British Columbia Utilities Commission's decision G-165-20. Additionally, there are a small number of assets that are depreciated using the straight-line amortization method of depreciation. These accounts represent numerous units of property but very small portions of depreciable gas plant in service at the time of the depreciation study. The use of amortization depreciation was also approved in the British Columbia Utilities Commission's decision G-165-20. FEI does not use any non-straight line methods of depreciation.

Please refer to the response to BCUC Panel IR1 6.2 for an explanation of why the straight-line Average Service Life method of depreciation is appropriate for FEI.

6.2 Please discuss whether FEI considered other depreciation methods for the new 3 Bcf tank.

6.2.1 If so, please describe the depreciation methods FEI considered, including the advantages and disadvantages of each and the impact to the rate and net present value (NPV) of the 3 Bcf tank compared to the method used in the Application.

6.2.2 If not, please explain why FEI did not consider other depreciation methods.

Response:

FEI consulted with Concentric and followed its recommendations in using the straight-line Average Service Life method. The use of the straight-line Average Service Life method is consistent with FEI's current depreciation methodology for its assets, including the existing LNG tanks.

Concentric provides the following additional response which also addresses BCUC Panel IR1 6.2.2.

At the time of the application for the CPCN for the Tilbury LNG Expansion Project, FEI had recently filed a depreciation study with the British Columbia Utilities Commission where the straight-line Average Service Life method had been approved for all asset groups. The use of mixed methods is rare and usually results from specific and unique circumstances to the utility and used only when an alternative method may provide a better recognition of the consumption of the assets or to phase in a different and more appropriate approach.

Concentric investigated various depreciation methods in the completion of the recent depreciation study in order to find the most appropriate option for the specific circumstances of FEI. Given that Concentric views the service value of all FEI assets is consumed evenly over the average service life, Concentric recommended the straight-line, Average Service Life method of depreciation applied on a remaining life basis in this depreciation study. Concentric continues to believe that this method is appropriate for all asset groups for FEI at this time.

6.3 Please calculate the rate impact and NPV of the 3 Bcf tank assuming it was depreciated using non-straight line accelerated depreciation methods, such that depreciation expense is higher at the beginning of the tank life. As part of the response, please use the double-declining-balance method and the sum-of-the-years'-digits method for the calculation. Please discuss how the amounts calculated compare to the rate impact and NPV of the 3 Bcf tank as presented in the Application.

Response:

Please refer to the table below which compares the levelized delivery rate impact and NPV of the proposed 3 Bcf tank over a 67-year analysis period between depreciation rates calculated based on the straight-line depreciation method (as filed), the double-declining-balance method, and the sum-of-the-years'-digits method. The financial analysis for the double-declining-balance method and the sum-of-the-years'-digits method is based on depreciation rates determined by Concentric, which are provided in Attachment 6.3.

As shown in the table below, the difference in the delivery rate impact and in the PV of the incremental revenue requirement is small between the three depreciation methods.

- Both the double-declining-balance method and the sum-of-the-years' digits method would result in a slightly higher initial delivery rate impact in 2027 due to the higher depreciation expense; however, over a 67-year analysis period, the result would be a reduction in both the incremental revenue requirement and the levelized delivery rate impact.
- For both the double-declining-balance method and the sum-of-the-years'-digits method, the earned return is reduced over a 67-year period compared to the straight-line depreciation method because the higher depreciation in the early years results in a lower rate base for FEI and therefore lower earned return in those early years.
- For the double-declining-balance method, as explained in the response to BCUC Panel IR1 6.5, this method does not recover the full cost of the original expenditure over the 67-year period; therefore, the present value of the incremental revenue requirement over the 67-year analysis period is slightly less than the other two methods, both of which would recover the full costs within the 67-year analysis period. As shown in the response to BCUC Panel IR1 6.7, using the double-declining-balance method, there would be approximately $53.4 million of undepreciated and unrecovered value of the 3 Bcf LNG tank at the end of the 67 years that would need to be recovered beyond the 67-year period. For the straight-line depreciation method and the sum-of-the-years'-digits method, the original cost of the 3 Bcf LNG tank is essentially recovered by the end of the 67-year period.

Please refer to the response to BCUC Panel IR1 6.5 for a more detailed discussion, as well as the advantages and disadvantages of the two non-straight-line accelerated depreciation methods.

	Straight Line Depreciation Method *(As-Filed)*	Sum of the Years' Digit Method	Double Declining Balance Method
Incremental Revenue Requirement in 2027 ($ millions)	79.799	88.418	88.710
PV of Incremental Revenue Requirement 67 years ($ million)	**1,041.925**	**1,040.847**	**1,039.305**
Delivery Rate Impact in 2027 (%)	9.07%	10.05%	10.09%
Levelized Delivery Rate Impact 67 years (%)	**6.67%**	**6.66%**	**6.65%**
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.300	0.300

6.4 Please discuss whether a non-straight line accelerated depreciation method other than the double-declining-balance method and the sum-of-the-years'-digits method would be more appropriate to depreciate the 3 Bcf tank. If so, please elaborate and compare the rate impact and NPV of the 3 Bcf tank using this depreciation method with those presented in the Application.

Response:

The following response has been prepared by Concentric.

Concentric does not consider any non-straight line accelerated depreciation methods to be appropriate in the circumstances of FEI. Concentric is unaware of any non-straight line accelerated depreciation methodologies that have gained regulatory approval in Canada for the purposes of rate making. Concentric is aware that some utilities use the declining balance method and the sum of years digits methods for the purposes of tax calculations, however, to the best of Concentric's knowledge, there are no other non-straight line accelerated depreciation methodologies widely discussed in the depreciation literature. At this time, Concentric recommends that FEI continue the use the Average Service Life method for all plant in service, including the 3 Bcf tank assets.

6.5 Please discuss the advantages and disadvantages of using a non-straight-line accelerated depreciation method for the 3 Bcf tank.

Response:

The following response has been provided by Concentric.

Accelerated methods of depreciation are most commonly seen in property valuation, production well evaluations, and in the development of capital cost allowance schedules for income tax reporting. In these circumstances the consumption of the service value of the assets are sometimes not considered to be best represented by the expiry of time, but rather on the acknowledgement that the economic benefit of the asset to the company is highest in the early years of the asset life, or because of a desire of taxation authorities to stimulate the expenditure of capital in certain areas. However, accelerated methods are not generally accepted for the return of investment in rate regulated utilities. The recovery of investment early in the life of the asset, with lower levels of recovery later in life, is inherently against the manner in which utility assets are consumed and would result in generational inequity. Concentric is unaware of any utility utilizing a non-straight line accelerated depreciation method of depreciation for the purposes of rate making.

Double Declining Balance Method

The double declining balance method of depreciation applies double the annual depreciation expense to the net plant balance. This is in contrast to straight line depreciation, which calculates the depreciation rate on the gross plant balance.

This method has the advantage of a constant depreciation rate over the life of the asset, making annual accruals easier to manage, as compared to the Sum of Years Digits method. This is further advantageous because the annual accrual amount decreases while the rate stays constant, providing rate mitigation for future generations of rate payers. Further, this method is less sensitive to changes in the average service life than some depreciation methods because there is only a very small amount of investment left to the tail end of the asset's life.

The double declining balance method has two major flaws that make it inappropriate for rate regulation purposes. Primarily, this method does not match the consumption of service over the life of the asset. It assumes that the asset is more valuable in the early years, rather than at the end of life. However, rate payers receive the same value from a tank regardless of the age of that tank. Rate payers frequently use older assets without any knowledge or change to the service received. This forms a type of generational inequity, whereby today's users are paying for a service that will be to the benefit of future generations.

The other major flaw in the double declining balance method is the inability of this method to ever fully recover investment. The regulatory compact provides for the opportunity for a return of investment over the life of the asset. In the modelling used in response to BCUC Panel IR1 6.3, the original $401.27 million investment did not reach less than one dollar for over 500 years. This is not reasonable and does not represent a return of investment over the expected life of the assets. This inability to recover the full investment over the expected life further compounds the generational inequity, as rate payers are left paying for assets that have long been removed from service and introduces the risk of stranded assets.

Sum of the Years Digits Method

The sum of the years digits method calculates the depreciation rate by numbering each year of life in reverse order and summing to provide the denominator in the depreciation calculation. The depreciation rate for a given year is calculated by dividing the assigned number by the denominator. This provides a faster return of investment and often produces a higher depreciation rate in the early years than the double declining balance method. Because the early years have a slightly higher depreciation rate than the double declining balance method, it has been used most often in certain tax calculations. It also has the advantage of fully recovering all investment over the expected life of the plant in circumstances where the average service life estimate remains constant, unlike the double declining balance method.

The sum of the years digits method does not properly match the recovery of investment with the use of the asset. As in the double declining balance method, this can lead to generational inequity. Ratepayers today will be burdened with a higher rate in order to offset lower rates tomorrow.

The other major flaw in the sum of the years digits method is the sensitivity to changes in the estimated average service life. As the depreciation expense is calculated through the addition of years, any change to the estimate once made will result in the over or under collection of expense over the life of the asset. This method does not consider the position of the accumulated depreciation fund or deviations from the expected historical retirement dispersion in the calculation of the depreciation expense. Therefore, there is no ability to change an estimate as more information becomes available later in the life. Further, as this method does not utilize an Iowa curve, it assumes that there is no dispersion of retirements over the average expected life. This results in an inability to recover investment retired prior to the average service life estimate.

On pages 160 and 163 of the Updated Public Application, FEI states that it conducts a 67-year analysis period based on a 60-year post-Project analysis period (the average service life of a new 3 Bcf LNG tank) plus seven prior years for the estimated Project schedule.

In Schedule 5 in Confidential Exhibit B-2, Financial Model M-1 to the Application, FEI shows a balance at the end of the 67-year analysis period in year 2086 for Net Plant-in Service.

6.6 Please confirm, or explain otherwise, that Net Plant-in Service (Line 14 of Schedule 5) is the mid-year estimated undepreciated balance of only the 3 Bcf tank.

Response:

Not confirmed. Line 14 of Schedule 5 shows the mid-year net plant-in-service (or mid-year estimated undepreciated balance) of all assets related to the TLSE Project, which as shown in Table 6-2 of the Application, includes the new 3 Bcf LNG tank, regasification equipment, ground improvement, and auxiliary system. Please refer to the response to BCUC Panel IR1 6.7 for the undepreciated balance of only the 3 Bcf tank at the end of the 67 years.

6.7 Please compare the estimated undepreciated balance of the 3 Bcf tank at the end of the 67-year analysis period using the non-straight line accelerated depreciation methods provided in response to Panel IR 6.3 and 6.4 to the estimated undepreciated balance of the 3 Bcf tank in the Application. As part of the response, please compare the estimated undepreciated balance of the 3 Bcf tank in year 2050 in the 67-year analysis period using the non-straight line accelerated depreciation methods and the estimated undepreciated balance in the Application.

Response:

Please refer to Table 1 and Table 2 below for the estimated undepreciated balance of the 3 Bcf tank only at the end of the 67th year and 31st year (at the end of 2050), respectively, over a 67-year analysis period for the three depreciation methods discussed in BCUC Panel IR1 6.3. FEI clarifies that year 2050 is the 31st year of the analysis period (i.e., 7 years of construction plus 24 years post-construction).

FEI notes, as explained in the response to BCUC Panel IR1 6.5, both the straight-line depreciation method and the sum-of-the-years'-digit method are meant to recover the full costs of the assets over the estimated life of the assets, which is 67 years. The small undepreciated balance shown at the end of the 67th year in Table 1 below for the straight-line depreciation method and the sum-of-the-years'-digit method is due to the remaining value of the sustainment capital included in the financial analysis over the 67-year period, as discussed on page 162, Section 6.3 of the Application. For the double-declining-balance method, the undepreciated value at the end of the 67 years would be approximately $53.4 million. As explained in the response to BCUC Panel IR1 6.5, the double-declining balance method will not recover the full cost of the original assets over the 67 years (i.e., there will still be an undepreciated value greater than one dollar in 500 years).

FEI also clarifies that the "Gross Plant-in-Service, Ending" at the 67th year and the 31st year shown in Tables 1 and 2 below, respectively, are different because of the sustainment capital additions each year as discussed on page 162, Section 6.3 of the Application.

Table 1: Estimated undepreciated balance of the 3 Bcf tank at the end of the 67th year (over a 67-year analysis period) for the three depreciation methods

3.0 LNG Tank ONLY (67-year Analysis Period)	Straight Line Depreciation Method *(As-Filed)*	Sum of the Years' Digit Method	Double Declining Balance Method
Year 2086 (67th Year of Analysis)			
Gross Plant-in-Service, Ending ($000s)	402,466	402,466	402,466
Accumulated Depreciation, Ending ($000s)	(401,744)	(401,554)	(349,043)
Undepreciated Balance at the end of 67th year ($000s)	**722**	**912**	**53,424**

Table 2: Estimated undepreciated balance of the 3 Bcf tank at the end of the 31st year (over a 67-year analysis period) for the three depreciation methods

3.0 LNG Tank ONLY (67-year Analysis Period)	Straight Line Depreciation Method *(As-Filed)*	Sum of the Years' Digit Method	Double Declining Balance Method
Year 2050 (24 Years of Useful Life)			
Gross Plant-in-Service, Ending ($000s)	401,591	401,591	401,591
Accumulated Depreciation, Ending ($000s)	(160,565)	(255,316)	(223,478)
Undepreciated Balance at the end of 2050 ($000s)	**241,026**	**146,274**	**178,113**

6.8 Please provide the estimated undepreciated balance of the 3 Bcf tank at the end of 2050 assuming a 24-year useful life of the proposed 3 Bcf tank (i.e. useful life to the end of 2050) using:

a. a straight line depreciation method and

b. an accelerated non-straight line method as provided in response to Panel IR 6.3 and IR 6.4.

Response:

FEI interprets this information request as seeking the undepreciated balance of the 3 Bcf tank at the end of 2050 assuming a 24-year average service life and accordingly provides this comparison between the three depreciation methods in the table below. FEI notes that it has used a 31-year analysis period, as this time period takes into account the 24-year post-construction average service life plus the 7 years of construction. For the undepreciated balance of the 3 Bcf tank at the end of 2050 over a 67-year analysis period (i.e., using a 60-year average service life), please refer to the response to BCUC Panel IR1 6.7.

3.0 LNG Tank ONLY (31-year Analysis Period)	Straight Line Depreciation Method	Sum of the Years' Digit Method	Double Declining Balance Method
Year 2050 (31st Year of Analysis)			
Gross Plant-in-Service, Ending ($000s)	401,574	401,574	401,574
Accumulated Depreciation, Ending ($000s)	(401,412)	(401,362)	(351,633)
Undepreciated Balance at the end of 2050 ($000s)	**162**	**212**	**49,941**

6.9 If FEI were to use an alterative depreciation method for the 3 Bcf tank, such as the accelerated depreciation methods described in Panel IR 6.3 and IR 6.4 or depreciated over a 24-year useful life, please discuss the mechanics of how the accounting for this would be implemented and if there would be any associated administrative considerations or costs.

6.9.1 Please discuss if this would result in a different accounting treatment for regulatory accounting purposes as compared to financial reporting and if there would be any administrative considerations or costs.

Response:

There would be minimal administrative costs to implement or maintain a different depreciation schedule for the 3 Bcf LNG tank. The 3 Bcf LNG tank can be recorded and tracked separately in a separate asset account on its own, with its own separate depreciation rate if required, and therefore can have its own specific depreciation schedule apart from FEI's other assets.

The accounting treatment for regulatory purposes would likely also be acceptable for external financial reporting. However, there is an assumption that the estimate used for depreciation in the external financial statements was chosen on the basis that it fairly allocates the cost of an asset over its relative useful life, which should align generally with an asset's service life. Depreciating the 3 Bcf LNG tank over a 24-year life, for instance, when the asset is expected to have a useful life to FEI and its customers of closer to 60 years, would mean the 24-year cost recovery of the asset may not be acceptable as depreciation for external financial reporting since it does not represent a fair allocation of the cost of the asset during its useful life. In this case, there may be significant administrative or additional costs, including consulting fees incurred for modifications to SAP, that would be required to manage different depreciation records (for example, regulatory using a 24-year life and external financial reporting using a 60-year life) for the same asset.

6.10 Please explain FEI's approach for the write-off of assets that are no longer used and useful for regulatory accounting purposes.

6.10.1 In the event that the 3 Bcf tank is no longer used and useful in the future, please explain whether FEI considers that any write off associated with the tank should be to the account of FEI's shareholders or ratepayers.

6.10.2 If FEI were to use an alternative depreciation method for the 3 Bcf tank, such as the accelerated depreciation methods as described in Panel IR 6.3 and IR 6.4, please discuss if this would result in write-off considerations that are different from those described in response to BCUC IR 1.10.1.

<u>Response:</u>

FEI believes the reference in BCUC Panel IR1 6.10.2 was intended to refer to BCUC Panel IR1 6.10.1, not BCUC IR1 1.10.1 or 10.1, as neither of these are related to the discussion in this IR.

FEI follows normal asset accounting for the write-off of assets that are no longer used and useful for regulatory purposes. When assets are retired, an accounting entry is done crediting plant in service and debiting accumulated depreciation, with any remaining net book value for the retired assets assigned to accumulated depreciation for recovery in future depreciation expense. Please refer to the response to BCUC IR1 40.4 which discussed FEI's approved group accounting methodology in detail, and discussed how the approved depreciation rates are designed to also recover the remaining net book value of retired assets.

In the event that the 3 Bcf tank is no longer used and useful in the future, FEI considers it is reasonable that the retirement of the asset and recovery of any remaining cost associated with the tank would follow the accepted practice and be recovered from ratepayers. The subject of retirement/asset losses and their recovery has been thoroughly explored in past FEI regulatory proceedings. As referenced in the response to BCUC IR1 40.5, in the BCUC's decision on FEI's 2012-2013 RRA, the BCUC approved the recovery of under-recovered depreciation (referred to as "Asset Losses")[21]:

> The Commission Panel notes that in this case a number of factors resulted in the Asset Losses and there was no evidence of asset misuse by the Utilities. **Therefore, the Panel directs that the Asset Losses be recovered from ratepayers, as proposed, in current depreciation rates.**

There is no reason to believe the 3 Bcf LNG tank would be misused (as described in the quote above) or the retirement (or early retirement) of the tank would be considered imprudent in any other way.

From an accounting perspective for treatment of asset losses and gains, FEI notes there would be no difference between the straight-line depreciation method that FEI currently uses and the accelerated depreciation methods discussed in BCUC Panel IR1 6.3 to 6.5. In the case of an accelerated depreciation method such as the sum-of-the-years'-digits depreciation method, it is possible that the assets might be over-depreciated prior to the retirement; however, the "asset gains" would be returned to ratepayers in future depreciation rates, consistent with the treatment for "asset losses" that would be recovered from ratepayers as discussed above.

[21] FEU 2012-2013 RRA Decision, p. 88: https://www.bcuc.com/Documents/Proceedings/2012/DOC_30355_04-12- 2012-FEU-2012-13RR-Decision-WEB.pdf.

7.0 Exhibit B-26, BCUC IR 91.4

PV of Incremental Revenue Requirement

In response to BCUC IR 91.4, FEI provided a table which shows the present value (PV) of incremental revenue requirement and the levelized delivery rate impact over a 67-year analysis period if the service life of the proposed 3 Bcf tank were to end in 2050 (i.e., in 24 years), as compared to the proposed 60-year service life.

	Useful Life of 24 years (to 2050) for the proposed 3 Bcf LNG Tank	Useful life of 60 years for the proposed 3 Bcf Tank as per Application
PV of Incremental Revenue Requirement 67 years ($ millions)	880.800	1,041.925
Delivery Rate Impact in 2027 (%)	11.90%	9.07%
Levelized Delivery Rate Impact 67 years (%)	5.64%	6.67%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.254	0.301

7.1 Please provide the PV of the incremental revenue requirement and the levelized delivery rate impact over a 24-year analysis period, as opposed to the 67-year analysis period used in the Application, that reflects a useful life of the proposed 3 Bcf tank to the end of 2050.

Response:

Please refer to the table below for the PV of incremental revenue requirement and levelized delivery rate impact over a 31-year analysis period (24 years useful life to 2050 plus 7 years of construction):

	Financial Analysis over 31 years (24 years Useful Life to 2050 plus 7 years of construction)	Financial Analysis over 67 years (60 years Useful Life plus 7 years of construction) as per Application
PV of Incremental Revenue Requirement ($ millions)	896.744	1,041.925
Delivery Rate Impact in 2027 (%)	11.90%	9.07%
Levelized Delivery Rate Impact (%)	6.90%	6.67%
Levelized Delivery Rate Impact ($/GJ)	0.311	0.301

7.2 Please provide the PV of the incremental revenue requirement and the levelized delivery rate impact of the proposed 3 Bcf tank if FEI's load forecast were to change by +/- 10 percent, +/- 25 percent, and +/- 50 percent over the 67-year analysis period.

Response:

FEI notes that changes to FEI's load forecast would not impact the PV of the incremental revenue requirement and the levelized delivery rate impact in percentage terms. This is because the incremental revenue requirement of the TLSE Project is made up of O&M, property tax, depreciation expense of the assets, amortization expense of the deferral account, income tax and FEI's earned return on the assets in FEI's rate base. None of these are dependent on FEI's load forecast.

However, changes in FEI's load forecast would have an impact on the levelized delivery rate impact of the TLSE Project in $ per GJ (i.e., if the load forecast increases by 10 percent, then the delivery rate in $ per GJ decreases by 10 percent such that FEI would recover the same amount of revenue). Please refer to the table below which shows the levelized delivery rate impact in $/GJ over the 67-year period for the different load forecast scenarios requested:

	-50%	-25%	-10%	0% (As-Filed)	+10%	+25%	+50%
Levelized Delivery Rate Impact ($/GJ)	0.602	0.401	0.334	0.301	0.273	0.241	0.201

7.2.1 Please discuss how a load increase or decrease would directly or indirectly impact the future cash flows of the Project. As part of the response, please discuss whether the Project's future cash flow is a relevant consideration in determining the useful life of the Project's assets for the purpose of setting depreciation rates in accordance with US Generally Accepted Accounting Principles (GAAP).

Response:

As discussed in the response to BCUC Panel IR1 7.2, an increase or decrease in load forecast would have no impact on the PV of the incremental revenue requirement. It also would have no impact on FEI's ability to finance the Project during the construction stage. Therefore, it would have no impact on the future cash flows of the Project. To clarify, an increase or decrease in the load forecast would result in a corresponding increase or decrease in the delivery rate, such that the same amount of revenue would be collected each year, thereby not impacting annual cash flows.

The Project's future cash flow is not a relevant consideration in determining the useful life of the assets under US GAAP. Rather, the useful life of the assets under US GAAP was an input to the future cash flow model. As outlined in Section 6.3 of the Application, the 67-year analysis includes a 7-year construction period and a 60-year average service life, as determined in consultation with independent, third-party advisors who have completed previous depreciation studies for FEI.

8.0 Exhibit B-1-4, Section 4.4.1.5

Direction No. 5 to the BCUC

Ancillary Revenue

In section 4.4.1.5 of the Updated Public Application, FEI describes the ancillary services and benefits associated with a 3 Bcf tank.

Section 3 of Direction No. 5 to the BCUC states:

In setting rates under the Act for a utility, the commission must do all of the following:

(a) treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service;

(b) allocate all costs and revenues related to CNG service and LNG service to all applicable customers;

(c) allow recovery of costs of purchasing LNG under the agreement referred to in section 5 (1) (b) of this direction.

8.1 Please confirm, or explain otherwise, that all ancillary services (e.g. LNG export activities and storage contracting opportunities) using the proposed 3 Bcf tank would be considered part of FEI's natural gas class of service and included in FEI's revenue requirements.

Response:

FEI confirms that any revenue received from ancillary services, including any potential future storage contracting opportunities to support LNG export by another entity, would be considered part of FEI's natural gas class of service and included in FEI's revenue requirements for the benefit of customers.

Attachment 1.4

FORTIS BC™

Diane Roy
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February 18, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599185

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Coastal Transmission System Transmission Integrity Management Capabilities Project (Application)

Response to the British Columbia Utilities Commission (BCUC) Panel Information Request (IR) No. 1

On February 11, 2021, FEI filed the Application referenced above. On February 4, 2022, BCUC staff responded by email with BCUC Panel IR No. 1. FEI respectfully submits the attached response to BCUC Panel IR No. 1. FEI would be pleased to respond to any further questions from the Panel.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

1.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1 (Application), pp. 65, 76; Exhibit B-5, BCUC IR 2.9.1; FEI Comprehensive Review and Application for a Revised Renewable Gas Program, Exhibit B-11,

pp. 76–78, 81–82

Hydrogen Blending

On page 65 of the CTS TIMC Application, FEI states:

> This pipeline replacement (PLR) alternative involves replacing the existing pipeline in its entirety with a new pipeline coated with a high integrity coating that is not conducive to the formation of SCC.

On page 76 of the CTS TIMC Application, FEI provides the following high level financial analysis of the electro-magnetic acoustic transducer in-line inspection (EMAT ILI), PLR and pipeline exposure and recoat (PLE) alternatives:

Table 4-4: NPV Cost Comparison of Three Remaining Alternatives (2020$)

	Alternative 4: EMAT ILI ($ millions)	Alternative 5: PLR ($ millions)	Alternative 6: PLE ($ millions)
NPV of Capital Cost	$225	$1,818	$1,909
NPV of O&M Costs (Savings)	$82	$(7)	$(7)
NPV of Total Capital and O&M Costs	$307	$1,811	$1,902

In response to BCUC Information Request (IR) 2.9.1, FEI stated:

> FEI is still evaluating the impact of an increasing concentration of hydrogen in FEI's natural gas system on the risks posed by stress corrosion cracking, including SCC crack growth behaviour, and is unable to provide discussion at this time.

On pages 76-77 of the Comprehensive Review and Application for a Revised Renewable Gas Program (Renewable Gas Program Review), FEI stated:

> [H]ydrogen presents a significant opportunity to complement RNG in decarbonizing the provincial gas supply. There is strong policy support to develop hydrogen as a low-carbon fuel within the energy mix to meet long-term decarbonization goals. For instance, the BC Hydrogen Strategy states: "Large-scale deployment of renewable and low-carbon hydrogen will play an essential role in reducing B.C.'s emissions."
>
> FEI is involved with multiple national and international joint initiatives that aim to rapidly develop a hydrogen ecosystem capable of producing and distributing hydrogen affordably as part of a lower carbon energy supply. Through its involvement, FEI intends to learn best practices from pioneering hydrogen projects

that may be applied in BC. As FEI's understanding of hydrogen production, distribution and end-use applications develops, FEI will pilot projects that will test the use of hydrogen in closed systems. FEI is currently progressing to pre-feasibility planning and technical analyses for introducing hydrogen into the gas distribution network before 2025 and is evaluating large-scale projects for the centralized production and distribution of hydrogen.

On page 81 of the Renewable Gas Program Review, FEI stated:

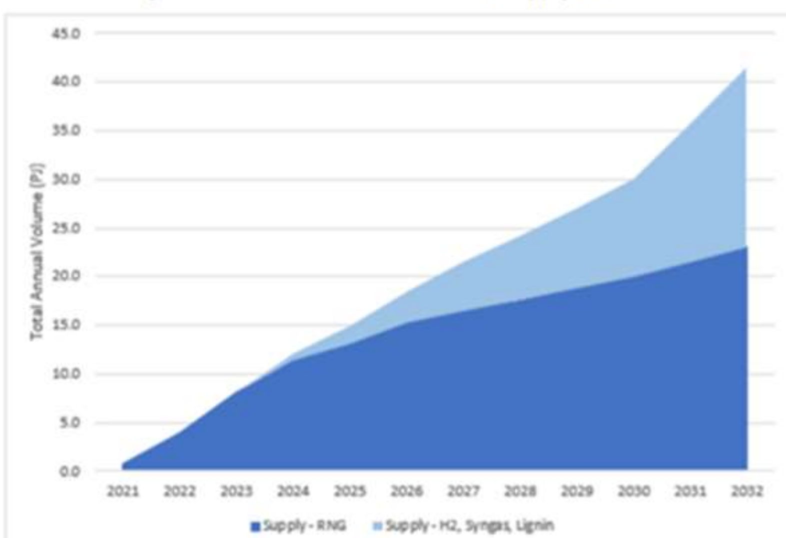
> There are technical and regulatory barriers to integrating alternate forms of Renewable Gas, such as hydrogen, into the gas system. These barriers could delay the use of hydrogen, synthesis and lignin to provide FEI's customers with low carbon energy services. FEI is undertaking steps to ensure that the existing gas pipeline system can accommodate other forms of Renewable Gas and, as applicable, that there are alternative methods to deliver these gases to customers. [Emphasis added]

On page 82 of the Renewable Gas Program Review, FEI stated:

> Assessing the blending of hydrogen into the gas supply, including a technical readiness evaluation. FEI is also in the process of testing how hydrogen interacts with pipeline materials, components and other equipment on its system, enabling hydrogen transport as a blend in the gas system, and the feasibility of hydrogen transport via repurposed high pressure transmission pipelines with a long-term goal of repurposing segments of existing natural gas networks for the delivery of 100 percent hydrogen gas. [Emphasis added]

On page 78 of the Renewable Gas Program Review, FEI provided the following 10-year renewable gas supply forecast:

Figure 6-3: 10-Year Renewable Gas Supply Forecast



1.1 Please provide an update regarding FEI's evaluations into the impacts of blending increasing concentrations of hydrogen into its natural gas transmission and distribution systems.

Response:

FEI continues to advance a range of activities to study, test, and verify that hydrogen is safe to use in the existing gas system and to identify any changes that may be required to ensure the continued safe operation of the gas system. As FEI discusses in the responses to these IRs, regardless of these activities, the data collected by EMAT ILI is necessary to allow FEI to identify and address any cracking threats on the CTS pipelines today. FEI's CTS pipelines will continue to be used and useful as they are capable of safely transporting a blend of hydrogen and large scale replacement of the CTS is neither expected nor cost-effectively feasible. As FEI has an obligation to provide safe service to its customers, FEI cannot defer the CTS TIMC Project due to the potential for hydrogen-related developments on its system.

The following provides background regarding blending hydrogen in pipelines and describes FEI's ongoing activities to investigate doing so.

Hydrogen-ready pipe is well understood

Hydrogen gas has been safely stored and transported in high-pressure steel tanks and pipelines for many decades. As such, the engineering challenges are well understood. Pipelines that are considered fully hydrogen-ready have been specified, designed, and constructed from their outset to transport pure hydrogen. As such, consideration is given to materials, components, and procedures (e.g., pipeline steel, welds, gaskets/seals, valves, etc.) that are known to be able to operate in a pure hydrogen environment.[1] However, even pipe that was not designed and constructed from the outset for hydrogen service can still transport meaningful quantities of hydrogen, in some cases with little to no modifications, as FEI explains below.

Preliminary analysis shows FEI's CTS can transport a blend of hydrogen

FEI has completed preliminary analysis to understand the admissible limits for hydrogen blending for its existing natural gas infrastructure and end-use customer equipment and applications. The analysis was informed by current industry knowledge and indicates that the existing transmission pressure pipelines in the Lower Mainland can transport a blend of hydrogen and natural gas. This is consistent with industry experience from hydrogen blending pilot projects around the world that have consistently demonstrated that steel pipelines can accommodate low hydrogen concentrations (approximately 10 percent or less) with no negative effects.

[1] https://h2tools.org/.

EMAT ILI will be a valuable input to establishing an upper limit for hydrogen blending

While FEI is confident that it can safely transport low concentrations of hydrogen in the CTS, there is no industry-accepted "bright-line" demarcation between hydrogen percentages that are considered acceptable versus unacceptable. This is because every pipeline configuration is different, including the pipe material (e.g., grade and thickness of the steel), operating pressure, gas composition, etc. Even pipe that was not designed from the outset to be hydrogen-ready may still be determined to be capable of transporting hydrogen in higher concentrations. This is done by conducting an engineering assessment which considers a range of factors such as the pipeline design, asset records, and operating history to determine what level of hydrogen blending can be accommodated without negative impacts to the pipeline. One of the inputs to this assessment is data collected from various inline inspection tools including MFL, C-MFL and EMAT. As such, the EMAT ILI data to be collected by the CTS TIMC Project will form a valuable input into determining the allowable concentration of hydrogen in each of the CTS pipelines.

FEI is investigating methods to mitigate risks of higher hydrogen blends

Hydrogen has different chemical properties compared to methane. The most significant concern in the context of steel pipelines is variously known as "hydrogen embrittlement" or "hydrogen-induced cracking". Hydrogen gas is made up of hydrogen molecules which can dissociate into hydrogen atoms on the inside surface of steel pipe and, because hydrogen is the smallest atom, it has some propensity to adsorb into the steel lattice comprising the pipe body and welds. This can degrade the mechanical properties of the steel, and, in simple terms, can cause it to become more brittle and result in the formation or growth of cracks. This is why the data collected by EMAT ILI, which will allow FEI to identify and address any cracking threats on the CTS pipelines, will also help FEI evaluate the safe operation of the CTS pipeline under various hydrogen blending scenarios in the future. FEI is also investigating emerging industry solutions to inhibit hydrogen embrittlement, such as the presence of small quantities of oxygen. Further research and technical assessment is ongoing to analyze if the levels at which the oxygen is present would be sufficient to mitigate the risk of embrittlement if high concentrations of hydrogen were added to the CTS pipelines.

Update on FEI activities

FEI provides an update below on the following ongoing activities:

1. Gas system readiness, system-planning and deployment strategy;
2. Industry collaboration, research and development, feasibility work;
3. Pilot and demonstration project development; and
4. Codes, Standards and Regulations.

1. Gas System Readiness, System Planning and Deployment Strategy

In 2021, FEI completed the scope definition and budget and schedule planning for a project to confirm the admissible limits for hydrogen blending for its existing natural gas infrastructure and end-use customer equipment and applications in British Columbia. This project will start in 2022 and focus on the following key objectives to be completed by 2024:

- Develop a system-wide hydrogen impact assessment to determine the acceptable range of hydrogen content throughout the gas system and confirm hydrogen blend level targets in the gas system that would be suitable for safe long-term operation;
- Determine longer-term increases to the hydrogen blend targets that would be feasible with continuing research, regulatory amendments and codes and standards development, mitigation measures, and network upgrades;
- Identify existing locations throughout FEI's gas service areas with the capability to support initial clusters of hydrogen production and distribution to initiate and grow market demand;
- Develop a hydrogen deployment roadmap to address the technical uncertainties, overlapping project requirements, and any limitations on system capacity to optimize for larger-scale hydrogen production, distribution and use; and
- Develop a deployment strategy to manage change and address safety, training, and education for internal operations and supply chain stakeholders, and the wider societal perceptions and considerations.

2. Industry Collaboration, Research and Development, Feasibility Work, Sector Specific Approaches:

FEI has been a member of various ongoing joint industry partnerships with both private industry and university institutions since 2017 that are in the process of testing how hydrogen interacts with pipeline materials, components, and other gas system equipment using hydrogen blend concentrations in natural gas from 5 percent up to 100 percent by volume. The key objectives of these activities include:

- Advance the adoption of new ways and means to distribute hydrogen and new end-use applications;
- Evaluate the technical and economic feasibility of large-scale projects for the centralized production and distribution of hydrogen;
- Advance involvement with multiple international joint initiatives that aim to share scientific knowledge and technical guidance to rapidly develop the ecosystems that can affordably produce and distribute fuels such as hydrogen as a clean energy supply;
- Engage industry expertise to research the feasibility of hydrogen transport via repurposed natural gas pipelines with a long-term goal of repurposing some segments of existing natural gas networks to 100 percent hydrogen service; and

- Continue to examine and learn best practices from pioneering hydrogen projects that can be applied in BC.

3. Pilot and Demonstration Project Development:

FEI's understanding of hydrogen production, distribution, and end-use applications continues to expand. As such, FEI has also begun developing pilot and pre-commercial demonstration projects to test hydrogen production and the use of these low-carbon fuels in a closed system. The key objectives of this activity are:

- Initiate hydrogen development and deployment through strategic demonstrations with university institutions and other development activities to scale supply and demand in key sectors;
- Demonstrate via hydrogen injection/blending pilot projects the viability and safety of hydrogen as a renewable fuel by addressing the technical uncertainties of introducing hydrogen into the existing gas network, and the potential impacts on end-users;
- Demonstrate a hydrogen micro-grid using hydrogen specific infrastructure to capture, clean, deliver and use byproduct hydrogen to decarbonize industry; and
- Pilot hydrogen separation to remove hydrogen from natural gas steam at locations where this may be necessary.

4. Codes, Standards and Regulations

FEI continues to engage with the various standards working groups to modify and develop safety and technical standards and set longer-term objectives to transition the regional natural gas network to adopt hydrogen. This includes hydrogen-ready infrastructure initiatives, including the certification of new appliances and equipment and the design of hydrogen-compatible natural gas infrastructure. The key objectives of this activity are:

- Harmonize codes and standards across jurisdictions (provincial and international) to ensure that best practices are applied across the domestic and international hydrogen economy.
- Work with the CSA Z662 *Oil and Gas Pipeline Systems* standard task force to review and update the requirements for gas pipelines. This will ensure that pipelines containing pure hydrogen, hydrogen blends, or biomethane blended with natural gas are fully aligned with or incorporated into the CSA Z662 and CSA Z245 *Steel Pipe* standards.
- Develop an FEI corporate hydrogen standard that will guide all aspects of hydrogen blending in the natural gas supply and that will allow FEI, or third-party suppliers, to blend hydrogen into the gas network.

1.2 Based on the 10-year renewable gas supply forecast reproduced above, what percentage (by energy) of the gas in the CTS will be hydrogen in: i) 2030; ii) 2040; and iii) 2050.

Response:

By 2030, FEI expects that there will be minimal hydrogen in the gas flowing in the CTS pipelines. FEI cannot know at this time what the precise percentage of hydrogen in the gas in each CTS pipeline will be in 2040 or 2050, but FEI expects that methane (whether from conventional or renewable sources) will continue to exceed 80 percent by volume of the gas transported by the CTS pipelines for at least 20 years. Additional amounts of hydrogen to support FEI's low-carbon diversified pathway may also be transported by other new or repurposed infrastructure.

1.3 Please explain whether there will be a need to replace existing pipeline segments of the CTS to accommodate the distribution of hydrogen. If so, please indicate the anticipated timing of such replacement.

1.4 Please explain whether there will be a need to repurpose existing pipeline segments of the CTS for the delivery of 100 percent hydrogen. If so, please indicate the anticipated timing of such replacement.

1.4.1 Please explain whether repurposing existing pipeline segments of the CTS would involve replacing the entire length of or portions of the selected pipeline segments with new hydrogen-tolerant piping.

1.5 Please explain whether any of the pipelines modified in the CTS TIMC Project will no longer be used or useful following the blending of increasing concentrations of hydrogen into the CTS. Please explain why or why not.

1.6 Please confirm that, had FEI proposed the PLR as its preferred alternative, the pipeline materials and/or the pipeline coatings would have been selected to ensure the CTS is hydrogen-tolerant. If confirmed, please provide any additional cost related to that selection and its impact on the net present value (NPV) of the PLR alternative.

Response:

While there is some uncertainty around the future pace of hydrogen adoption and distribution for FEI, this uncertainty has no impact on the need for the CTS TIMC Project. FEI expects that the CTS pipelines will continue to be used and useful.

In summary:

- The CTS pipelines will continue to be used and useful. They can accommodate a blend of hydrogen today and EMAT ILI will be a valuable input to establishing an upper limit for hydrogen blending.
- If 100 percent hydrogen distribution is pursued by FEI in the future, this may be done through retrofitting existing infrastructure, by new infrastructure, or by production of hydrogen closer to the point of use.
- EMAT ILI is a significantly more cost-effective solution as compared to PLR and will allow long-term operation of the CTS pipelines, even in a future where hydrogen blending is contemplated.
- The data collected by EMAT ILI is necessary to allow FEI to identify and address any cracking threats on the CTS pipelines today.

FEI expands upon each of these concepts below.

The CTS pipelines will continue to be used and useful

FEI's CTS pipelines will continue to be used and useful. As discussed in the response to BCUC Panel IR 1.1, FEI has completed preliminary analysis which indicates that the existing transmission pressure pipelines in the Lower Mainland can transport a blend of hydrogen and natural gas. This is consistent with industry experience from hydrogen blending pilot projects around the world which have consistently demonstrated that steel pipelines can accommodate low concentrations (approximately 10 percent or less) with no negative effects. While there is no industry-accepted "bright-line" demarcation between hydrogen percentages that are considered acceptable versus unacceptable, EMAT ILI information will be a valuable tool to help determine what level of hydrogen blending can be accommodate without negative impacts to the pipeline.

If 100 percent hydrogen distribution is pursued by FEI in the future, this may be done through retrofitting existing infrastructure, by new infrastructure, or by production of hydrogen closer to the point of use.

At this time, FEI does not know which, if any, of the segments of the CTS might need to be replaced or repurposed, nor the timing of this work. However, FEI does not envision that the CTS pipelines would be removed and replaced with new hydrogen-ready pipelines, as this would not be a cost-effective method to potentially support 100 percent hydrogen distribution. Instead, by 2030, FEI envisions that blending of hydrogen would expand across the low-pressure gas distribution system, with the potential for segments of the system around hydrogen hubs to be converted to 100 percent hydrogen. Between 2030 and 2050, as demand for hydrogen grows, FEI envisions that the existing gas system pipeline corridors would be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and (bio)methane in a progressively decarbonized gas system. Additional amounts of hydrogen to support FEI's low-carbon diversified pathway may also be transported by other new or repurposed infrastructure.

In all these potential scenarios, EMAT ILI will continue to be needed to address the risk of cracking threats on the CTS pipelines.

All of the pipeline segments modified by the CTS TIMC Project will be used and useful following the blending of increasing concentrations of hydrogen into the CTS

As explained in Section 5.4.2 of the Application, replacement of some pipeline segments is included within the scope of the CTS TIMC Project. During their design and construction, FEI will consider the potential for future use of these pipeline segments to transport increasing percentages of hydrogen. For clarity, these limited replacements may not make the overall pipeline capable of transporting high concentrations of hydrogen, but they may eliminate possible future bottlenecks and allow FEI to increase hydrogen blending concentrations in certain pipelines for little to no cost.

Including future pipeline replacement costs in the NPV analysis for the PLR alternative is not necessary

FEI confirms that had it proposed the PLR as its preferred alternative, the pipeline materials and/or the pipeline coatings would have been selected to ensure the CTS would be hydrogen-tolerant. However, the NPV financial analysis of the PLR alterative need not account for future costs to replace segments of the CTS with hydrogen-tolerant piping. As discussed in the Application and FEI's arguments filed in this proceeding, the PLR alternative is not financially feasible and EMAT ILI is the only feasible alternative to address the threat of cracking on the CTS. As shown in Table 3-9 of the Application, the CTS consists of approximately 254 km of pipeline and replacing all these pipelines would be highly impactful to customers and the public. Further, as shown in Table 4-4, the cost would be at least an order of magnitude higher than the CTS TIMC Project cost. The potential for hydrogen developments on the CTS does not change FEI's conclusion that PLR is not feasible.

CTS TIMC Project is needed now

The only prudent course of action at this time is to modify the existing CTS pipelines to allow them to be inspected using EMAT ILI. This will allow any existing cracking issues to be identified and addressed. Given that the CTS pipelines can carry a blend of hydrogen today, and replacement of the CTS to accommodate hydrogen is not reasonably contemplated, FEI's CTS pipelines will continue to be used and useful. As FEI has an obligation to provide safe service to its customers, FEI cannot defer the CTS TIMC Project due to the potential for hydrogen-related developments on its system.

The information gathered by EMAT ILI will also directly factor into FEI's analysis of determining what concentration of hydrogen each pipeline can safely accommodate in the future. In turn, this will allow FEI to determine a safe and cost-effective plan for transitioning to increased hydrogen distribution in the future. For example, EMAT ILI may identify that FEI could greatly increase the allowable concentration of hydrogen blending in a given pipeline by simply replacing short pipeline segments in limited areas. This would be cost effective for customers as it would allow for targeted upgrades to achieve higher levels of hydrogen concentration. The information provided by EMAT ILI is a necessary input to this determination.

Attachment 6.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)