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July 27, 2021

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

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 Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On February 11, 2021, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-149-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

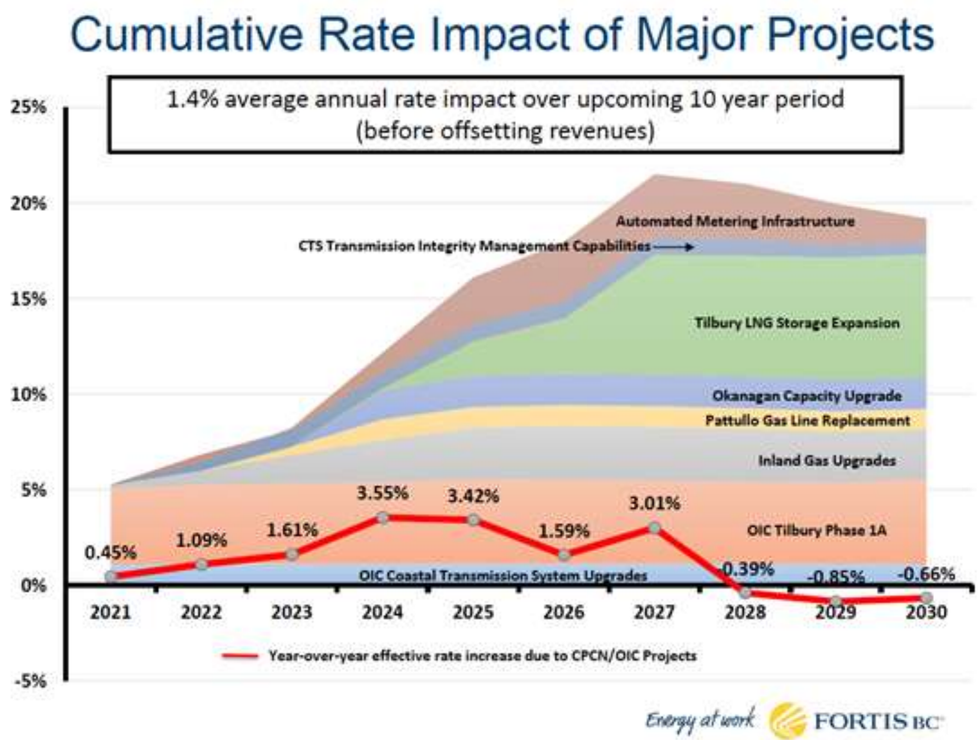
Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-4, page 5



1.1 Please provide the sources with quantification of the 'offsetting revenues'.

Response:

The offsetting revenues referenced in the figure in the preamble refer to revenues from the projects that support increased capacity or demand and the potential revenue from LNG sales under FEI's Rate Schedule 46 which would offset the rate impact of the Tilbury Phase 1A project. As discussed during the CTS TIMC Workshop,[1] FEI has not prepared a forecast of these offsetting revenues as they would vary year by year and are difficult to forecast. Moreover, the timing of these offsetting revenues are not necessarily aligned with the timing of the rate impact resulting from these projects.

1.2 Please provide the same graph with the offsetting revenues included.

[1] CTS TIMC Workshop Transcript Volume 1, page 10.

Response:

Please refer to the response to CEC IR1 1.1.

1.3 Please confirm that the rate impact is delivery rate impact and not the same as bill impact, which would include the costs of natural gas, and provide the estimated bill impacts for the above to provide context.

Response:

Not confirmed. The rate impact shown in the figure cited in the preamble is bill impact, and includes the delivery charge, cost of gas, and midstream rates. FEI also notes the rate impacts shown in the figure are compared to current 2021 approved rates.

2. Reference: Exhibit B-1, page 3 and 4

> FEI is seeking approval pursuant to sections 59 to 61 of the UCA to recover the portion of the balance in the deferral account related to the CTS TIMC Project by amortizing the December 31, 2021 deferral account balance related to the Project over 3 years commencing in 2022. FEI will continue to incur costs related to the ITS TIMC Project and record, and track them separately, in the deferral account and FEI will request recovery of those costs as part of the ITS TIMC project.

2.1 If the CTS TIMC Project has not, or not yet, received CPCN approval by January 2022, would FEI expect to defer its recovery or would the recovery occur in any event?

<u>Response:</u>

If the proposed deferral account is approved, recovery of the CTS TIMC Project deferred project costs will occur January 1 the year following the BCUC decision. As FEI currently does not anticipate receiving approval by January 2022, FEI is amending its approvals sought to request the transfer of the non-rate base deferral account to rate base on January 1, 2023 with amortization over a three-year period commencing at that time. Please also refer to the response to BCUC IR1 26.2 for further detail.

3. Reference: Exhibit B-1, page 11 (Section 3)

> As required by regulation, FEI manages threats to the integrity of its transmission pipeline systems in a proactive and systematic way through its IMP-P. However, integrity management practices continually improve as the industry learns more about the threats to pipelines and as it develops new tools and techniques to manage them. This is the case with the threat of cracking. Cracking is a threat to the safe operation of pipelines that has the potential to grow during the operation of a pipeline and lead to failures, including ruptures. The industry is learning that pipelines are more susceptible to cracking threats than previously believed, and industry practice is moving towards active monitoring and mitigating cracking threats on larger diameter pipelines using EMAT ILI tools. However, costly modifications to pipelines and related facilities can be required in order to enable the use of these tools.

3.1 Please provide a list of regulations that are relevant to this application in requiring FEI to manage its transmission pipelines in a proactive and systematic way through its IMP-P or identify where they may be found on the public record.

<u>Response:</u>

FEI is subject to many regulations that require it to manage its transmission pipelines in a proactive and systematic way through its Integrity Management Policy and Integrity Management Program for Pipelines (IMP-P). The BC *Oil and Gas Activities Act* (OGAA) [2] and the associated BC Pipeline Regulation (BC Reg. 147/2014)[3] and referenced standards comprise the overarching regulatory requirements for the safe operation of transmission pipelines, including their management in a proactive and systematic way. Key relevant requirements are as follows:

Regulatory Requirement	Significance / Relevance to FEI's management of its transmission pipelines in a proactive and systematic way
Section 37 (1) (a) of the OGAA states, "A permit holder, an authorization holder and a person carrying out an oil and gas activity must prevent spillage"[4]. This requirement pertains to pipelines operating at or above a pressure of 700 kPa.	FEI's primary objective with its IMP-P is to prevent failure incidents that could result in significant safety, environmental, and/or reliability consequences. FEI has obligations as a "Permit Holder" under the OGAA to prevent all release of product from its BC OGC regulated pipeline system. This obligation influences FEI's selection of asset management strategies over the lifecycle of a pipeline, with preference given to a methodology (such as ILI) that provides FEI with the capability to monitor and proactively respond to potential changes to asset condition that occur with time.

[2] http://www.bclaws.ca/Recon/document/ID/freeside/00_08036_01.

[3] http://www.bclaws.ca/civix/document/id/complete/statreg/281_2010.

[4] "Spillage", as defined in the OGAA, means "petroleum, natural gas, oil, solids or other substances escaping, leaking or spilling from (a) a pipeline, well, shot hole, flow line, or facility, or (b) any source apparently associated with any of those substances."

Regulatory Requirement	Significance / Relevance to FEI's management of its transmission pipelines in a proactive and systematic way
Section 3 (1) of the BC Pipeline Regulation requires operators to manage pipelines throughout their lifecycle in accordance with CSA Z662 and Annex A of CSA Z662. Annex A is titled: "Safety and Loss Management System".	CSA Z662:19 defines a Safety and Loss Management System as "a systematic, comprehensive, and proactive set of interrelated processes for the management of safety and loss control associated with activities throughout the lifecycle of a pipeline system …". This requires that FEI is systematic in its approach to managing its transmission pipelines.
Section 7 (2) of the BC Pipeline Regulation requires operators to have a pipeline integrity management program, defined as "a program for the purpose of managing the integrity of a permit holder's pipeline and that complies with CSA Z662 and Annex N of CSA Z662."	CSA Z662:19 Annex N mandates that a pipeline system integrity management program is an integral part of the Safety and Loss Management System. Safety and reliability of gas transmission pipelines is only achieved by proactive failure prevention, and FEI's IMP-P is developed with the intent of predicting and preventing, in a proactive and systematic way, transmission pipeline failures. ILI is an effective tool, when available, for failure prevention as it provides detailed information on asset condition.

The regulatory provisions that apply to FEI's gas transmission pipelines are typically goal-oriented rather than prescriptive in nature. In other words, the requirements of pipeline operators are typically expressed as outcomes to be achieved rather than as descriptions of how to achieve those outcomes. FEI has defined the activities within its IMP-P for the purposes of achieving the outcomes listed above, including those associated with its in-line inspections.

3.2 To what extent are EMAT ILI tools already in use in other jurisdictions? Please provide the names of the jurisdictions in Canada and the US and the total length of pipelines using EMAT ILI to date.

Response:

FEI is aware of EMAT ILI tools being used throughout the world to manage cracking in transmission pipelines, and that their adoption is increasing throughout Canada and the US. FEI does not have access to the total length of pipelines using EMAT ILI to date in Canada and the US.

Please also refer to the response to RCIA IR1 2.1 which documents FEI's awareness through public sources that all major operators of natural gas transmission pipelines in British Columbia, namely FEI, Westcoast, and Pacific Northern Gas have adopted EMAT ILI tools, and FEI's further awareness of EMAT ILI adoption by all Canadian Energy Pipeline Association members who are natural gas pipeline operators.

4. Reference: Exhibit B-1, page 6

> The total capital cost estimate for the CTS TIMC project is $137.8 million (as-spent), which includes AFUDC. As described in Section 6 of the Application, the Project will result in an estimated cumulative delivery rate impact of 1.32 percent by 2026 when all construction is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the five years from 2022 to 2026 is estimated to be 0.26 percent annually or $0.013 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $1.19 per year over the five years, or $5.96 cumulatively by 2026.

4.1 Please provide the average and range of bill impacts for each rate class.

Response:

The table below provides both the average annual bill impact and cumulative bill impact for FEI's Rate Schedules 1 to 7 based on the delivery rate impact shown in Table 6-5 of the Application. FEI has excluded transportation customers, as FEI does not have insight into their total bill including their commodity charges.

Average Bill Impact ($)	Avg. Use per Customer (UPC) in GJ	Avg. Annual Impact (2022-2026)	Cumulative Impact (2022-2026)
$/GJ		**$0.013**	**$0.066**
Residential			
Rate Schedule 1	90	$1.19	$5.96
Commercial			
Rate Schedule 2	340	$4.50	$22.51
Rate Schedule 3	3,770	$49.91	$249.56
Industrial			
Rate Schedule 4	9,050	$119.82	$599.09
Rate Schedule 5	16,240	$215.01	$1,075.05
Rate Schedule 6	2,060	$27.27	$136.37
Rate Schedule 7	177,950	$2,355.96	$11,779.82

5. Reference: Exhibit B-1, page 6

1.3.4 FEI Will Account for Environmental and Archaeological Considerations

Section 7 provides an overview of the Project environment, including a discussion of the environmental and archaeological impacts that the Project may have and FEI's plans to mitigate those impacts.

Based on an Environmental Overview Assessment (EOA), FEI expects that the Project's scope, which is confined to existing rights of way and facilities, will have low to moderate environmental risks and any potential environmental impacts of the Project can be mitigated through the implementation of standard best management practices and mitigation measures.

FEI will be conducting an Archaeological Overview Assessment (AOA) in early 2021 to assess the Project's potential archaeological impacts. FEI also plans to conduct an Archaeological Impact Assessment (AIA) to further assess potential archaeological and cultural impacts within areas of moderate and high archaeological potential identified in the AOA. The AIA will provide

5.1 Is the Archaeological Overview Assessment complete?

5.1.1 If yes, please provide.

5.1.2 If no, please explain why not and when it will be completed.

<u>Response:</u>

Please refer to the response to BCUC IR1 31.3.

6. Reference: Exhibit B-1, page 13 and page 14

> **3.2.2.1 *Modern Pipe Manufacturing Processes Result in Superior Pipe Materials***
>
> Steel and pipe manufacturing practices and processes have continually evolved and significant improvements have occurred since the early 1970s. Pipe manufactured prior to 1970 is often referred to as "vintage" pipe and pipe manufactured after 1970 is referred to as "modern" pipe. Vintage pipe can contain a larger quantity of manufacturing anomalies, with the majority of these anomalies occurring in the seam welds, which are also referred to as longitudinal welds. The quantity of manufacturing anomalies also varies with pipe manufacturer. Types of manufacturing anomalies are further discussed in Section 3.2.4.2.
>
> **3.2.2 Integrity of Pipelines is Established During Design, Manufacturing, Installation and Commissioning**
>
> The integrity of a pipeline is initially established through the engineering design, manufacturing, installation and commissioning processes. Engineering design must not only reflect regulations and adopted standards, but must also anticipate and provide necessary integrity management capabilities. Design processes establish important specifications pertaining to manufacturing, installation, and commissioning. The following subsections describe the manufacture of pipelines in FEI's transmission systems and the steps taken after manufacturing to ensure their ongoing integrity. Figure 3-2 provides a reference for the pipeline features and terminology discussed in this section.

6.1 Please confirm, or otherwise explain, that FEI has, over time, adhered to all relevant regulations regarding pipeline construction and installation, and utilized what would be considered as high-quality processes at the time of manufacture and installation for all its pipelines.

6.1.1 If not, please explain why not.

6.1.2 If not, please provide a discussion of what regulations were not adhered to and when and where this occurred.

Response:

FEI confirms that it adhered to all relevant regulations regarding pipeline construction and installation, and utilized what would be considered to be high-quality processes at the time of manufacture and installation for all its pipelines.

7. Reference: Exhibit B-1, page 18 and page 19

> **3.2.3 FEI Monitors and Maintains Integrity of Pipelines During Their Operation**
>
> As discussed in this section, throughout their operation, pipelines may be exposed to hazards and threats, such as corrosion and cracking, that can undermine their integrity. However, with an effective integrity management program, hazards and threats can be managed to keep pipelines operating safely and reliably indefinitely.
>
> **3.2.3.2 *Overview of FEI's Integrity Management Program – Pipeline (IMP-P)***
>
> FEI manages the integrity of its transmission pipeline systems with its IMP-P. FEI's IMP-P meets the requirements of the BC *Pipeline Regulation* under the *Oil and Gas Activities Act* (OGAA). The *Pipeline Regulation* requires FEI to employ a quality management system with a plan-do-check-act (PDCA) cycle designed to promote continual improvement of its integrity management activities. Implementation of a quality management system, founded on PDCA principles, is the internationally recognized way for an industry to improve its asset performance and reduce failures over the life of assets. As such, it has been embedded within Canadian pipeline regulations, standards and industry practices.

7.1 Please confirm or otherwise explain that FEI has consistently maintained its pipelines according to all relevant regulation and industry standards.

7.1.1 If not, please explain why not.

7.1.1.1 Please identify where and when any lapses in maintenance have occurred.

7.1.1.2 Please identify the impact of any lapses on the integrity of FEI's pipelines and specifically identify and quantify any costs associated with the lapses in maintenance.

Response:

Confirmed. FEI has consistently maintained its pipelines according to all relevant regulation and industry standards.

FEI has indicated in multiple Annual Review proceedings dating back to 2016 that it was assessing "the need for and feasibility of adopting crack-detection capabilities within its in-line inspection program".[5] FEI's determination that EMAT ILI was sufficiently proven and commercialized for adoption in its system dates from August 3, 2018, with its application for the TIMC Deferral Account in the FEI Annual Review for 2019 Rates.

FEI's implementation of the CTS TIMC Project on the proposed Project schedule enables it to continue maintaining its pipelines according to all relevant regulation and industry standards.

[5] FEI Annual Review for 2017 Rates, Response to BCUC IR1 9.11, submitted September 21, 2016; FEI Annual Review of 2018 Rates, BCUC IR1 1.9 and 6.17, submitted September 26, 2017.

8. Reference: Exhibit B-1, page 22

> As ILI technology has developed for smaller pipeline diameters, FEI has undertaken two significant projects over the past 20 years to expand its ILI capabilities:
>
> - **Transmission Pipeline Integrity Plan (TPIP)**: From 2000 to 2005, the TPIP expanded FEI's ILI capabilities for geometric and metal-loss imperfections to all larger-diameter transmission pipelines, primarily focused on lines of diameter greater than NPS 10.
> - **Inland Gas Upgrade (IGU):** From 2020 to its expected construction completion in 2024, the IGU will expand FEI's ILI capabilities for geometric and metal loss imperfections to smaller diameter transmission pipelines, focused on lines of diameter as small as NPS 6 (limited by the availability of proven and commercialized ILI tools).
>
> Operators and integrity-related service providers (e.g., ILI and leak detection vendors) have invested significantly in the development of technology to support the ongoing management of integrity hazards, as evidenced by the existence of new tools and technology on the market. In recent decades, significant technological development has occurred in the area of ILI, including most recently, the development and commercialization of EMAT ILI tools that are capable of detecting and sizing certain types of cracking and other two-dimensional defects. At the time of this Application, EMAT tools suitable for FEI's natural gas pipelines of NPS 10 and larger have been sufficiently commercialized.

8.1 Is it fair to describe the EMAT ILI tools as being novel? Please explain why or why not.

<u>Response:</u>

EMAT ILI tools are no longer considered novel and are the best available technology for mitigating cracking threats in natural gas pipelines.

In its report "Best Available Technologies in Federally-Regulated Pipelines"[6], dated 30 September 2016, the National Energy Board (now the Canada Energy Regulator) stated:

> Though an emerging technology, EMAT is more generally described as a controlled implementation. The principal challenge is that it tends to find defects that are not there (false positives). However, the technology has been under development for some 20 years, and has become more sensitive and reliable so that now EMAT can be considered BAT [Best Available Technologies] for ILI crack detection in gas pipelines.

Although the above-referenced report was published nearly five years ago, it is indicative of the trend of EMAT ILI increasingly being adopted by industry (as described by FEI in Section 3.3.2 of the Application). As indicated by the report, EMAT has now been under development for approximately 25 years.

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[6] https://www.cer-rec.gc.ca/en/about/publications-reports/best-available-technology/report/bstvlbltchnlgrprt-eng.pdf.

While the maturity and capabilities of EMAT technology are continually evolving, another necessary consideration is the commercial availability of tools suitable for FEI's natural gas pipelines. Until recently, EMAT ILI tools were not commercially available for pipe diameters as small as NPS 10. As discussed in Section 3.2.2.3 of the Application, the issue of suitability includes that the ILI tools must be operable within the variable flow rates encountered on FEI's system. Please refer to the response to CEC IR1 7.1 which explains that EMAT ILI was sufficiently proven and commercialized for adoption in FEI's system since 2018.

Please also refer to the responses to RCIA IR1 2.1 and CEC IR1 3.1 that describe the adoption and use of EMAT ILI in British Columbia, Canada, and worldwide.

8.2 Is it possible that the suitable EMAT tools will be either further developed for superior performance, or come down in price over the next 5 years? Please explain.

Response:

Based on FEI's experience with other ILI technologies, FEI expects that the performance of EMAT tools will continue to evolve and improve over the next five years and beyond. However, FEI cannot predict whether the cost to run EMAT tools will increase or decrease in price over the next five years.

For clarity, to FEI's awareness, pipeline operators (including FEI) do not purchase ILI tools. Instead, pipeline operators contract with ILI vendors who develop, test, and construct ILI tools for the industry and then offer pipeline inspection services to customers. Thus, the ILI tool related cost, development, and obsolescence risks are borne by the ILI vendors, not the pipeline operators.

8.3 To the best of FEI's knowledge, please describe any new technologies that are being developed but have not yet reached commercialization.

8.3.1 Please identify the benefits that are associated with the new technologies and whether or not they offer advantages relative to the technologies proposed to be adopted by FEI at this time.

8.3.1.1 Please quantify any cost benefits that could be generated by any of these new technologies.

8.3.2 Please explain when any of these technologies are expected to be commercialized.

8.3.3 Would FEI expect to implement any of these new technologies at a later date? Please explain why or why not.

8.3.3.1 If yes, when would FEI expect to do so?

Response:

FEI is not aware of any new crack detection ILI technologies for use in gas transmission pipelines that are under development and have not yet reached commercialization.

9. Reference: Exhibit B-1, page 22

> For ILI tools to be suitable for FEI's pipelines, they must be able to operate within the variable flow rates on FEI's system. Unlike many other gas transmission systems where flow is dependent on the daily volumes contracted by midstream shippers, the flow through the FEI transmission system is almost entirely dependent on FEI's customer demand, which is temperature sensitive. During peak winter months (typically November through March), gas flows in FEI's transmission pipelines are high compared to the shoulder and light-load seasons (typically approximately April to October). For this reason, FEI has limited windows during which it can run ILI tools. During high demand – and even some lighter load – periods, gas flow rates can be sufficiently high that the ILI tool travels through the pipe at an excessive speed and hence cannot collect valid data. Recently, newer ILI tools have been developed which allow a variable portion of the gas flow to bypass the tool as it travels through the pipe. This allows the tool to control its own speed in real time to ensure consistent collection of high-quality data. Given the widely varying flow rates in FEI's system, it is expected that the use of these newer speed-control tools will be required in many instances.

9.1 Please confirm or otherwise explain that FEI's transmission system must have the variable flow rates in order to serve its end-use customers.

<u>Response:</u>

FEI does not actively impose flow variations. Rather, such variations are a system response to serving the customer demand (i.e., the fluctuating flow rates in the CTS are a result of the end-use customers daily and seasonal consumption requirements). The CTS does not have flow control on its existing transmission lines. Thus, the flow rate in any transmission line in the system will vary because the downstream customer demand also varies.

10. Reference: Exhibit B-1, page 23

3.2.4 Cracking Threats to FEI's System

Cracking threats are considered "planar imperfections" that, due to a lack of volume, cannot be detected by FEI's current ILI tools. Cracks have a measurable length and depth, but are sufficiently narrow that they do not typically have a measurable width associated with their dimensions. Cracking threats affect the strength of a pipeline by effectively reducing the wall thickness of the pipeline. The two main types of cracking threats to FEI's system are SCC and crack-like imperfections in the seam weld of a pipeline. In addition, SCC and crack-like imperfections can interact with other time-dependent integrity threats, such as external corrosion, to compound integrity issues on a pipeline.

Table 3-1: Summary of ILI Tool Feature Detection Capabilities

	Geometry	MFL	CMFL	EMAT
Dents	✓			
Wrinkles / Buckles	✓			
Metal loss		✓ (circumferentially-oriented features)	✓ (narrow longitudinally-oriented features)	
Long seam weld location			✓	✓
Girth weld location	✓	✓	✓	✓
SCC and crack-like features				✓
Longitudinal seam weld flaws				✓

10.1 Please explain what is meant by 'due to a lack of volume' and why it means that planar imperfections cannot be detected. Volume of what?

Response:

Cracks are considered planar because they are essentially two dimensional. Pipeline cracks have a length and a depth, but negligible width – similar to a crack in a car windshield. Corrosion and metal loss features (which FEI's current ILI tools can detect) are three dimensional, with a length, depth, and width. This results in a three-dimensional void in the pipeline wall – similar to a chip or "bulls-eye" in a car windshield. Without this third dimension, a crack has negligible volume, and as a result, cannot be detected by the sensors used in current ILI tools as they are only able to detect the presence of voids (i.e., lost or missing metal).

11. Reference: Exhibit B-1, page 26

> conditions. These imperfections are related to the way the pipe is manufactured. As described in Section 3.2.2.1, most of FEI's transmission pipelines have been manufactured by either ERW or submerged arc welding (SAW and DSAW). The seam weld imperfections that could arise from these manufacturing processes are listed below.
>
> - Potential imperfections in ERW seam welds:
>   - Lack of fusion;
>   - Inclusions; or
>   - Hook cracks.
> - Potential imperfections in SAW and DSAW seam welds:
>   - Toe cracks; or
>   - Transit fatigue.

11.1 If FEI had used pipeline manufactured using other processes, would FEI still likely experience similar or different imperfections? Please explain.

Response:

In addition to ERW and submerged arc welding (SAW and DSAW), FEI has used pipe manufactured using spiral welded process in limited locations of its transmission pipeline system. FEI has also used seamless pipe for some of its transmission station piping. Seamless pipe is manufactured by a hot extrusion process, and therefore it does not have a weld seam. These pipes are not susceptible to seam weld anomalies but are susceptible to several different types of imperfections.

11.1.1 If FEI might not have experienced imperfections using pipeline manufactured with other processes, please explain how the use of pipeline manufactured using other processes might have mitigated the current risks and quantify any potential cost savings.

Response:

If FEI had used pipe without a seam weld there would be no risk associated with seam weld failures; however, there is typically a 30 percent cost premium for seamless pipe versus welded pipe. Further, seamless pipes would not lead to inspection cost savings as EMAT ILI would still be required to manage SCC in the pipe body.

11.1.2 If FEI might not have experienced imperfections using pipeline manufactured with other processes, please explain why FEI selected pipeline manufactured using the ERW or SAW and DSAW processes.

Response:

Please refer to the response to CEC IR1 11.1. FEI selected pipeline manufactured using the ERW, SAW and DSAW processes because these were the most commonly used pipe in the industry at the time of construction. FEI determined that this pipe was technically acceptable, readily available, and cost effective at the time of selection.

12. Reference: Exhibit B-1, page 26 and page 27

3.2.5 FEI's Existing Integrity Management Practices Do Not Identify All Cracking

FEI's current integrity management practices for managing cracking threats involve the inspection of its transmission pipelines for cracking during "opportunity digs", when the pipeline is exposed because of other pipe condition assessments. These digs are referred to as "opportunity digs," as the primary reason for the integrity dig is not related to cracking. These integrity digs are scheduled for other reasons, including the following:

- To assess metal loss anomalies (e.g., corrosion) identified through ILI and to repair or replace if necessary;
- To assess mechanical damage anomalies (e.g., dents, gouges) identified through ILI and to repair or replace if necessary; and
- To assess sites identified through above-ground surveys of its pipelines without ILI capability and to repair or replace if necessary.

During an integrity dig, in addition to the primary anomaly assessment (e.g., visual analysis, measurement, and assessment of the corrosion, dent, or gouge), FEI performs an industry-standard, non-destructive evaluation methodology called magnetic particle inspection (MPI). MPI provides a visual indication of microscopic imperfections along the exposed surface of the steel pipe, which may be indicative of cracking. FEI addresses any cracking through pipeline repairs or replacement, as necessary, and records any SCC-related findings for future tracking. Through these digs FEI is aware of the existence of cracking threats on its system and has been monitoring such threats on its transmission pipeline system as part of its IMP-P.

FEI estimates that the total amount of pipeline exposed to date as part of the Integrity Dig Program (and hence assessed for cracking) is less than one percent of the total length of pipe in FEI's transmission system. As such, these opportunity digs are not expected to have identified all cases of cracking due to the limited lengths that have been exposed relative to the full length of buried pipelines.

As cracking is a highly localized and often unpredictable phenomenon, it is also not possible to use the analysis from integrity digs to determine where cracking may be occurring on other segments of FEI's pipelines. Crack initiation and growth is a complex function of a number of factors.[10] As described in Section 3.2.4.1, SCC requires the presence of three factors: a susceptible material, a tensile stress, and a suitable environment. The degree of contribution from each of these factors varies such that SCC found at one location cannot be relied upon for locating SCC at other locations. As such, it is not possible to pinpoint the exact locations where SCC will occur simply through assessing the factors that cause it. FEI's current practices therefore do not provide the capability of identifying all instances of cracking on FEI's pipelines.

12.1 Please provide the estimated range of costs for conducting an integrity dig that was not opportunistic – i.e. for the express purpose of checking pipeline condition.

<u>Response:</u>

The estimated range of costs for conducting an integrity dig that was not opportunistic would not be significantly different than for opportunity integrity digs.

Integrity dig costs, in general, vary significantly and can range from $0.010 million (e.g., shorter-length excavation site, accessible to equipment, minimal permits and environmental impacts, minimal site restoration costs) to $0.150 million and higher (e.g., dig below a remote stream location, helicopter site access, extensive site management required during the dig, extensive site restoration, and the complexity of repair requirements).

12.2 Could FEI improve its ability to manage cracking threats by undertaking a random integrity dig program conducted for the express purpose of identifying cracking? Please explain why or why not.

12.2.1 If yes, could such a program be cost-effective? Please explain why or why not.

Response:

FEI provides the following response:

No, FEI could not improve its ability to manage cracking threats by undertaking a random integrity dig program conducted for the express purpose of identifying cracking. A random integrity dig program would have no certainty that the most significant, and hence most likely to fail, cracking would be found. As stated in Section 3.2.5 of the Application, cracking is a highly localized and unpredictable phenomenon. As such, without full inspection of the pipeline, either through in-line inspection or exposing the entire pipeline for external inspection, the risk associated with cracking could not be effectively mitigated.

JANA provides the following response:

Given the nature of cracking threats, a random integrity dig program is not a viable approach for managing cracking. For cracking threats, highly localized factors combine to drive the mechanism of failure and the cracking can vary significantly meter to meter along the pipeline. Given a typical integrity dig is on the order of 10 to 20 meters it is not practical to inspect enough of the pipeline to identify with certainty the most significant SCC on the pipeline. Due to similar reasons, random integrity digs provide limited information for a QRA (Quantitative Risk Assessment).

13. Reference: Exhibit B-1, page 28

> The transmission pipeline industry works collaboratively to prevent pipeline failures as a failure on any pipeline affects the entire industry. Through the experiences of other gas transmission operators managing cracking on pipelines, FEI is aware that SCC (which could lead to failure) has been found on pipelines similar to those operated by FEI (i.e., with similar coatings, age, diameters, and operating stress level).

13.1 Please provide the number of instances in which SCC has been found on pipelines similar to those operated by FEI and in which year the findings were made.

Response:

FEI does not have public access to the number of instances in which SCC has been found on pipelines similar to those operated by FEI and in which year the findings were made.

Please also refer to the response to RCIA IR1 2.1.

13.2 Please quantify the total length of pipeline examined that resulted in instances of cracking.

Response:

FEI does not have public access to this type of information.

14. Reference: Exhibit B-1, page 28

JANA observes the following regarding the increasing knowledge of cracking threats:[11]

> Historically, the majority of significant SCC has been associated with [polyethylene] tape. However, as companies have expanded monitoring, significant SCC has been found on asphalt-coated lines and on coal-tar coated pipe (previously considered to have a low susceptibility to SCC). This is consistent with the overall trend of SCC being found more and more in pipelines previously thought to be less susceptible, as the time dependent mechanisms at play continue to manifest themselves.

14.1 Does FEI use polyethylene tape?

Response:

FEI has historically used polyethylene tape as a field applied joint coating and as a repair coating. FEI has also used polyethylene tape as the pipe body coating on a limited number of segments of transmission pipeline. FEI does not currently use polyethylene tape.

14.2 Does FEI use asphalt-coated lines or coal-tar coated pipe? Please explain.

Response:

FEI installed asphalt-coated and coal-tar coated pipe up until the early 1980s. While these coatings have not been used in pipeline installations since that time, FEI still has approximately 1,000 kilometres of transmission pressure pipelines in service which use these coatings.

14.3 Is the CEC correct in understanding that polyethylene tape fails more quickly than either asphalt coated lines or coal-tar coated lines?

14.3.1 If not, please explain why not.

14.3.2 If yes, please provide an estimated timeline range in years for when each type of line is likely to develop stress corrosion cracking.

Response:

Coating failure depends on a number of factors including the quality of its application, the soil environment, and soil stresses. Polyethylene tape is considered more susceptible to failure compared to asphalt coating or coal-tar coating; however, a coating failure can occur under a similar timeframe with asphalt and coal-tar coating.

15. Reference: Exhibit B-1, page 29

A summary of the feedback from other transmission pipeline operators regarding their recent experiences with EMAT is provided below:

- EMAT ILI has been run in pipelines with previously observed cracking, with diameters from NPS 10 to 42 and operating at a stress level greater than 30 percent SMYS. As technology becomes available, the operators plan to run EMAT ILI in smaller diameter pipelines.
- EMAT ILI has been successful in detecting crack-like features, although discriminating SCC within these crack-like features has been challenging. This uncertainty warrants conservative initial assessments followed by field verification digs in conjunction with laboratory material testing.
- The operators use a risk assessment (either qualitative, semi-quantitative, or quantitative) to prioritize EMAT ILI runs.
- Common challenges with successfully running EMAT ILI tools are:
  - Need for launching/receiving barrel modifications to accommodate EMAT ILI tools which are typically longer than other ILI technology tools;
  - Need for pipeline modifications such as removing heavy-wall sections and tight bends to minimize tool speed excursions;
  - Cleaning pipelines for optimal sensor performance so that crack-like features can be detected and sized to the best of tool capability; and
  - Controlling tool speed during the run in low-flow and/or customer-demand dependent pipelines.

Consistent with this evolving industry knowledge and practice, FEI advanced the TIMC Project to assess the threat of cracking on its larger diameter pipelines operating at transmission pressure, and assess the need to enhance its approach to managing cracking threats on these pipelines.

15.1 Please explain from when FEI 'advanced' the TIMC Project. Was such a project scheduled to occur at a later date, and if so, when?

Response:

FEI's use of the term 'advanced' was in relation to proceeding with the current Project and does not refer to expediting a project that was planned to occur at a later date. FEI has recognized cracking as a potential threat to its system for approximately two decades as part of its existing integrity dig program on the CTS as part of its Transmission Pipeline Integrity Program (TPIP). FEI initiated the current Project in response to the availability of proven, commercialized, and adopted ILI tools and consistent with industry best practice.

The following activities occurred during the development of the TIMC project:

- **September 21, 2016**: FEI indicated it was assessing the need for and feasibility of adopting crack-detection capabilities within its in-line inspection program in the Annual Review for 2017 Rates, BCUC IR1 9.11.
- **September 26, 2017:** FEI indicated that it was continuing its assessment in the Annual Review for 2018 Rates, BCUC IR1 1.9.
- **August 3, 2018:** FEI applied for a new non-rate base deferral account to capture development costs for the TIMC Project in the Annual Review for 2019 Rates, as approved by Order G-237-18.

FEI's TIMC project is comprised of two CPCN applications: one for the CTS TIMC, and another for the ITS TIMC. FEI confirms that it has no other projects currently planned to address cracking threats to its transmission pipelines.

15.2 Please describe any differences between any other project planned and that being undertaken.

15.2.1 If FEI did not have any other project planned, is it because FEI did not expect that cracking could occur? Please explain.

Response:

Please refer to the response to CEC IR1 15.1.

16. FEI CPCN for the Inland Gas Upgrade Application page 31 and Appendix E page 3

ILI is highly regarded by operators as the data enables rehabilitation efforts to be focused on specific locations. ILI also enables proactive asset management by providing pipeline wall condition data (including changes over time) that can inform long-term asset planning.

Crack detection ILI technology (commonly referred to as 'EMAT tools', as the technology relies upon electro-magnetic acoustic transducers) is another ILI tool that is increasingly being adopted by Canadian gas transmission pipeline operators for the detection of cracks and crack- like imperfections. It is also becoming increasingly commercially available for use in a variety of pipeline diameters.

16.1 The CEC notes that FEI implemented ILI, but not EMAT technology in its recent IGU project. Please explain the differences between the two technologies.

Response:

The differences between magnetic flux leakage (MFL) and EMAT ILI technologies are described in Section 3.2.3.3 of the Application as follows:

> … MFL tools are used for detecting and sizing three-dimensional metal loss defects, including corrosion and gouges. More recently, the industry developed circumferential magnetic flux leakage (CMFL) tools to address limitations in the capabilities of MFL tools to detect and size long, narrow, longitudinally-oriented metal loss." and "… EMAT ILI tools… are capable of detecting and sizing certain types of cracking and other two-dimensional defects.

16.2 Why did FEI not utilize EMAT ILI? Please explain.

Response:

EMAT ILI tools are not yet commercially available for pipeline diameters smaller than NPS 10. As such, the TIMC project focuses on larger diameter transmission pipelines. The IGU Project focused on smaller diameter transmission pipelines of primarily NPS 6 and NPS 8, and the adoption of proven, commercialized, and industry adopted ILI tools (i.e., MFL technology) for pipelines of those diameters.

16.3 Will FEI make application for the installation of EMAT ILI if the technology is or becomes technologically feasible for the laterals affected in the IGU project? Please explain why or why not.

Response:

FEI intends to continue to monitor available technology and industry practice for mitigating the potential for rupture of its transmission pipelines, including the laterals affected in the IGU Project. If proven and commercialized EMAT ILI technology becomes available and adopted by industry for transmission pipelines with diameters smaller than NPS 10, FEI would be obligated to evaluate the use of such technology and would make a decision at that time whether to introduce EMAT for such pipelines.

17. Reference: Exhibit B-1, page 29 and page 87 and page 89

3.3.3 Pilot Project Demonstrates that EMAT ILI Detects Previously Unknown Instances of Potential Cracking

As part of FEI's project development work, FEI is completing a pilot of EMAT ILI evaluations on two CTS pipelines. This pilot is in progress, and as such, FEI is in the process of validating potential cracking detected by the EMAT tool. These instances of potential cracking on FEI's pipelines were not previously detected through opportunistic digs.

The two pipelines chosen for the pilot, CPH BUR 508 and LIV PAT 457, had instances of cracking that FEI discovered during integrity dig activities, unrelated to investigating cracking. FEI determined that these pipelines could be modified to run EMAT ILI tools on a timeline suitable for informing the TIMC CPCN Project.

5.3.3.1 *LIV PAT 457*

In October 2019, FEI conducted a baseline inspection of the entire 29.8 km length of this pipeline, as shown in Figure 5-1 below. The Preliminary Report has been received, and while there was no severe cracking identified that warranted urgent repair work, the following features that had not been identified by FEI's current integrity management practices were reported:

- 5 crack features located in the seam weld
- 7 crack features located in the pipe, and
- 1 crack group

5.3.3.2 *CPH BUR 508*

In September 2020, FEI performed a baseline inspection of a 4.4 km long segment of this pipeline between Coquitlam Gate Station and Noons Creek Valve Station (referred to as COQ NOO 508), as shown in Figure 5-3 below. While there was no severe cracking identified that warranted urgent repair work, the following features that had not been identified by FEI's current integrity management practices were identified, and five initial integrity digs are scheduled for 2021:

- 4 linear indications
- 1 crack group

17.1 Please provide the operating pressures for each of the two pipelines as well as the maximum pipeline pressures permitted.

<u>Response:</u>

Please see the table below for the pressure information for the LIV PAT 457 and CPH BUR 508 pipelines.

Description	LIV PAT 457	CPH BUR 508
Average operating pressure	3,646 kPa	3,620 kPa
Maximum operating pressure	4,020 kPa	4,020 kPa

17.2 Please describe any further results, with quantification, that have been provided by the pilot that were not included in the application and evidence currently on the record.

Response:

Please refer to the response to BCUC IR1 11.1.

17.3 Why were significant repairs or replacements not required to address the instances of cracking?

Response:

Please refer to the response to BCUC IR1 11.1.

17.4 Please confirm that FEI takes these instances of cracking to be representative of other likely cracking on its pipelines.

Response:

FEI does not take these instances of cracking to be representative of other likely cracking on its pipelines.

17.5 Can the two pipelines FEI selected for the Pilot be considered as ‘typical’? Please explain why or why not.

Response:

FEI does not consider any pipeline to be 'typical' with respect to cracking, and therefore, does not consider the LIV PAT 457 and CPH BUR 508 pipelines to be typical. As described in Section 3.2.5 of the Application, SCC is highly localized and an often unpredictable phenomenon which is the result of the variable contribution of factors that can result in SCC. As such, while the pilot project pipelines may share similar characteristics with other CTS pipelines (e.g., coating type), the results from the EMAT ILI on these pipelines cannot be extrapolated to other pipelines or considered typical for the system.

18. Reference: Exhibit B-1, page 33

- Analysis that indicates the identified SCC can grow to failure under FEI operating conditions as:
  - Industry failures have been observed within the operating stress range of the FEI susceptible lines.
  - Analysis of SCC crack growth rates based on FEI operating conditions in conjunction with Dr. Chen of the University of Alberta indicate the potential for cracks to grow to failure and, with practical assumptions, in timeframes on the order of five years under the most aggressive condition.

18.1 Please describe what would be considered as 'aggressive' conditions, normal conditions, and favourable conditions.

Response:

JANA provides the following response:

'Normal' and 'favorable' conditions were not defined in the analysis. The analysis by Dr. Chen examined a range of conditions in terms of crack size (length and depth), pipe material fracture resistance that were considered reasonable estimates of what could be observed in the FEI system. The 'most aggressive condition' mentioned speaks to the combination of factors in the analysis which leads to the shortest projected failure times.

18.2 Please provide the likely timeframe for cracks to grow to failure under normal and favourable conditions.

Response:

JANA provides the following response:

Normal or favorable conditions were not defined in the JANA analysis. There is no one timeline for cracks to grow to failure. The timeline for cracks to grow to failure depends on the depth, length, local environment, steel properties, operating conditions, etc. The purpose of the analysis was not to define explicit times to failure (as there is not complete characterization of the cracking in the FEI system as would be provided by EMAT ILI analysis), but to assess if there was the potential for cracks to grow to failure given the FEI system conditions. The analysis showed that based on Dr. Chen's models and reasonable assumptions around the input values that cracks could grow to failure in the FEI system.

18.3 Are there particular steps that a crack needs to go through to reach failure? Please explain.

Response:

JANA provides the following response:

Based on Dr. Chen's model, there are typically 4 phases identified for SCC crack growth:

- Preparation:
  - Development of conditions for SCC initiation (e.g., coating failure)
- Stage 1:
  - Crack initiation and early stage growth by dissolution
- Stage 2:
  - Hydrogen-facilitated fatigue growth and increasing coalescence of cracks
- Stage 3:
  - Instable crack growth through the remaining wall thickness driven by stress and mechanical cracking failure

19. Reference: Exhibit B-1, page 25, 33 and 35-36

- Potential imperfections in ERW seam welds:
  - Lack of fusion;
  - Inclusions; or
  - Hook cracks.
- Potential imperfections in SAW and DSAW seam welds:
  - Toe cracks; or
  - Transit fatigue.

3.4.3.1 *CTS and ITS Pipelines Have the Same Properties as Pipelines Where Failures Have Been Observed by Other Operators*

JANA explains that it uses the term "susceptible" to indicate the potential for SCC or pipe seam cracking to initiate on the lines, based on the specific characteristics of the lines and their operating conditions. A "yes" susceptible line is one where the characteristics of the line are consistent with lines where SCC or pipe seam cracking has been observed on multiple systems within the broader pipeline industry. A "low" susceptible line is one with characteristics where no or very limited failures have historically been observed in the industry.

Table 3-5: FEI VITS Pipelines: Susceptibility to Cracking Threats based on Installation Year and Coating Type

#	Pipeline Short Name	Pipeline Full Name	SCC Susceptibility[1]	Seam Weld Cracking Susceptibility[1]	Original Install Year(s)	Coating Types	Seam Type(s)
1	ISL MAN 273	Little R - Mid Island 10"	Low	Low	1990	Extruded PE, Extruded PE - Multilayer	Unknown
2	LRN LOP 273	Little River North 10"	Low	Low	1990	Fusion Bonded Epoxy	ERW
3	LRS LOP 273	Little River South 10"	Low	Low	1990	Fusion Bonded Epoxy	ERW
4	PRN LOP 273	Powell River North 10"	Low	Low	1990	Fusion Bonded Epoxy	ERW
5	PRS LOP 273	Powell River South 10"	Low	Low	1990	Fusion Bonded Epoxy	ERW
6	SCN LOP 273	Secret Cove North 10"	Low	Low	1990	Fusion Bonded Epoxy	ERW
7	SCS LOP 273	Secret Cove South 10"	Low	Low	1990	Fusion Bonded Epoxy	ERW
8	TEX MAN 273	Texada S - Texada N 10"	Low	Low	1990, 1991	Extruded PE	ERW
9	VAN MAN 273	Watershed-Secret Cove 10"	Low	Low	1990, 1991	Extruded PE	Unknown
10	VAN MAN 323	V1-Watershed 12"	Low	Low	1991	Extruded PE	ERW

Notes:

[1] *A susceptibility rating of "Yes" indicates that the cracking type has been found on pipelines with similar attributes in the industry. A rating of "Low" indicates that there are relatively limited or no cases of that cracking type found on pipelines with similar attributes in the industry.*

Table 3-4: FEI ITS Pipelines: Susceptibility to Cracking Threats based on Installation Year and Coating Type

#	Pipeline Short Name	Pipeline Full Name	SCC Susceptibility[1]	Seam Weld Cracking Susceptibility[1]	Original Install Year(s)	Coating Types	Seam Type(s)
1	SAV VER 323	Savona – Vernon 12"	Yes	Yes	1957	Asphalt, Polymer Tape	Unknown
2	VER PEN 323	Vernon – Penticton 12"	Yes	Yes	1957	Asphalt, Polymer Tape	ERW
3	GRF TRA 273	Grand Forks – Trail 10"	Yes	Yes	1957	Asphalt, Polymer Tape	ERW
4	OLI GRF 273	Oliver Y – Grand Forks 10"	Yes	Yes	1957	Asphalt, Polymer Tape	ERW
5	PEN OLI 273	Penticton – Oliver Y 10"	Yes	Yes	1957	Asphalt, Polymer Tape	ERW
6	TRA CAS 219	Trail – Castlegar 8"	Yes	Yes	1957	Asphalt, Polymer Tape	Unknown
7	KIN PRI 323	Kingsvale – Princeton 12"	Yes	Low	1971	Extruded PE, Shrink Sleeve on girth welds	ERW
8	PRI OLI 323	Princeton – Oliver 12"	Yes	Low	1971	Extruded PE, Shrink Sleeve on girth welds	ERW
9	YAH TRA 323	Yahk – Trail (EKL) 12"	Yes	Low	1974, 1975	Extruded PE, Polymer Tape on girth welds	Unknown
10	OLI PEN 406	Oliver – Penticton 16"	Low	Low	1994	Extruded PE	ERW
11	DUK SAV 508	Duke Tap – Savona C/S 20"	Low	Low	1997	Extruded PE - Multilayer	ERW
12	YAH OLI 610	Yahk – Rossland 24", Rossland – Oliver 24"	Low	Low	2000	Fusion Bonded Epoxy	SAW

Notes:

[1] *A susceptibility rating of "Yes" indicates that the cracking type has been found on pipelines with similar attributes in the industry. A rating of "Low" indicates that there are relatively limited or no cases of that cracking type found on pipelines with similar attributes in the industry.*

19.1 Please confirm, or otherwise explain, that FEI's reference to pipe seam cracking incorporates all the types of potential imperfections noted on page 26 of the application.

Response:

JANA provides the following response:

Confirmed.

19.2 Are the SCC and Seam Weld susceptibilities for the types of pipelines recognized industry-wide, or is this a JANA-specific observation? Please explain.

Response:

JANA provides the following response:

The susceptibilities are recognized industry-wide based on reported historical failures.

19.3 What would constitute a rough numerical threshold that might trigger a 'susceptibility' categorization vs being considered a 'relatively low' susceptibility?

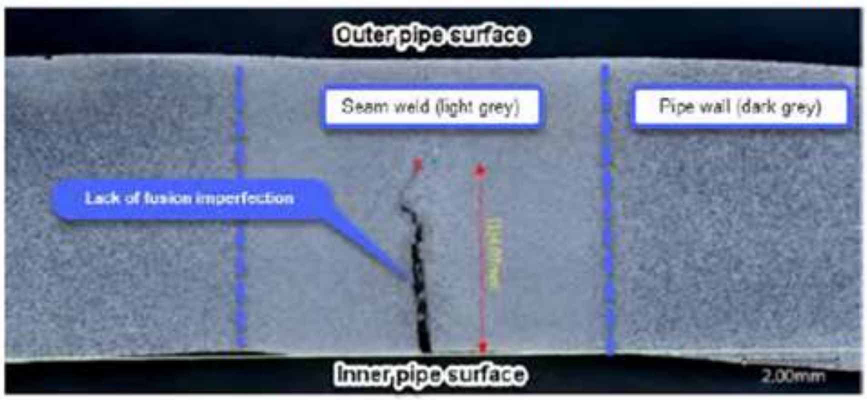
Response:

The 'Low' susceptibility assignment is a qualitative descriptor based on general industry experience without a hard numerical cutoff. For SCC, it is where a pipeline has had no, or very few, reported failures with other contributing factors. For seam weld cracking, it is based on the industry standard benchmark of post-1970, where construction practices changed.

20. Reference: Exhibit B-1, page 38

Figure 3-10: Examples of Stress Corrosion Cracking as Identified on FEI's Transmission Pipelines

Figure 3-11: Example of a Lack of Fusion Weld Imperfection found on a FEI Transmission Pipeline



20.1 Please provide a general timeline for how long it takes for a seam weld imperfection to result in a failure under aggressive, normal and favourable conditions, and describe those conditions if they differ from that for SCC.

Response:

JANA provides the following response:

Aggressive, normal and favorable conditions were not defined in the analysis.

The conditions for seam weld failure are different from those for SCC as they are driven by different mechanisms. Seam weld failures occur due to pre-existing seam weld imperfections from the manufacturing process combined with coinciding subsequent mechanical damage, such as dents, or other time-dependent integrity threats such as metal-loss corrosion. These pre-existing seam weld imperfections are most common in vintage pipelines (pre-1970). Failure can occur in any timeframe if mechanical damage or metal-loss corrosion occurs coincident with a seam weld imperfection. If there is no coincident additional factors driving failure, seam weld imperfections that have been pressure tested to 1.25 operating pressure are considered benign.

21. Reference: Exhibit B-1, page 39

Table 3-6: FEI CTS Pipelines: Occurrences of Cracking on FEI pipe identified through JANA's review of selected integrity digs

#	Pipeline Short Name	Pipeline Full Name	SCC Susceptibility	Seam Weld Cracking Susceptibility	Integrity Digs with Cracking Threats
1	HUN BAL 1066	Huntingdon – Balfour 42"	Yes	Low	0
	BAL NIC 1066	Balfour – Roebuck 42"	Low	Low	0
2	HUN NIC 762	Huntingdon – Nichol 30"	Yes	Yes	0
3	LIV COQ 323	Livingston – Coquitlam 12"	Yes	Yes	2
4	LIV PAT 457	Livingston – Pattullo 18"	Yes	Yes	9
5	NIC PMA 610	Nichol – Port Mann 24"	Yes	Yes	0
6	CPH BUR 508	Cape Horn – Burrard 20"	Yes	Yes	15
7	ROE TIL 914	Roebuck – Tilbury 36"	Yes	Low	0
8	TIL BEN 323	Tilbury – Benson 12"	Yes	Yes	4
9	TIL FRA 508	Tilbury – Fraser 20"	Yes	Yes	1
10	NIC FRA 610	Nichol – Fraser 24"	Yes	Yes	2
11	TIL LNG 323	Tilbury – LNG Plant 12"	Yes	Low	0
12	NOO EMT 610	Noons Ck – Eagle Mtn 24"	Low	Low	0
13	PMA CPH 914	Port Mann – Cape Horn 36"	Low	Low	0

Table 3-7: FEI ITS Pipelines: Occurrences of Cracking on FEI pipe identified through JANA's review of selected integrity digs

#	Line Name	FEI Name	SCC Susceptibility	Seam Weld Cracking Susceptibility	Integrity Digs with Cracking Threats
1	SAV VER 323	Savona – Vernon 12"	Yes	Yes	33
2	VER PEN 323	Vernon – Penticton 12"	Yes	Yes	22
3	GRF TRA 273	Grand Forks – Trail 10"	Yes	Yes	86
4	OLI GRF 273	Oliver Y – Grand Forks 10"	Yes	Yes	55
5	PEN OLI 273	Penticton – Oliver Y 10"	Yes	Yes	7
6	TRA CAS 219	Trail – Castlegar 8"	Yes	Yes	21
7	KIN PRI 323	Kingsvale – Princeton 12"	Yes	Low	1
8	PRI OLI 323	Princeton – Oliver 12"	Yes	Low	4
9	YAH TRA 323	Yahk – Trail (ELK) 12"	Yes	Low	8
10	OLI PEN 406	Oliver – Penticton 16"	Low	Low	0
11	DUK SAV 508	Duke Tap – Savona C/S 20"	Low	Low	0
12	YAH OLI 610	Yahk – Rossland 24", Rossland – Oliver 24"	Low	Low	12

21.1 For each table please add a final column demonstrating the number of integrity digs undertaken.

Response:

JANA provides the following response:

JANA is responding to this response as they did the original analysis. In the original analysis, 282 dig reports with cracking threats were identified from a total number of 543 integrity digs. Subsequent analysis has identified 402 dig reports with cracking threats, from a total number of 890 integrity digs. This provides enhanced confirmation of the presence of cracking threats in the FEI system. The updated tables are provided below with the added column indicating the total number of integrity digs for each line.

Table 3-6 Updated: FEI CTS Pipelines: Occurrences of Cracking on FEI pipe identified through JANA's review of selected integrity digs and total number of integrity digs between analysed

#	Pipeline Short Name	Pipeline Full Name	SCC Susceptibility	Seam Weld Cracking Susceptibility	Integrity Digs with Cracking Threats	Total Integrity Digs Analysed
1	HUN BAL 1066	Huntingdon – Balfour 42”	Yes	Low	0	1
	BAL NIC 1066	Balfour – Roebuck 42”	Low	Low	0	0
2	HUN NIC 762	Huntingdon – Nichol 30”	Yes	Yes	3	18
3	LIV COQ 323	Livingston – Coquitlam 12”	Yes	Yes	12	31
4	LIV PAT 457	Livingston – Pattullo 18”	Yes	Yes	22	38
5	NIC PMA 610	Nichol – Port Mann 24”	Yes	Yes	2	11
6	CPH BUR 508	Cape Horn – Burrard 20”	Yes	Yes	18	41
7	ROE TIL 914	Roebuck – Tilbury 36”	Yes	Low	0	0
8	TIL BEN 323	Tilbury – Benson 12”	Yes	Yes	4	5
9	TIL FRA 508	Tilbury – Fraser 20”	Yes	Yes	0	5
10	NIC FRA 610	Nichol – Fraser 24”	Yes	Yes	0	12
11	TIL LNG 323	Tilbury – LNG Plant 12”	Yes	Low	1	4
12	NOO EMT 610	Noons Ck – Eagle Mtn 24”	Low	Low	0	0
13	PMA CPH 914	Port Mann – Cape Horn 36”	Low	Low	0	0

1 **Table 3-7 Updated: FEI ITS Pipelines: Occurrences of Cracking on FEI pipe identified through**
2 **JANA's review of selected integrity digs and total integrity digs analysed**

#	Line Name	FEI Name	SCC Susceptibility	Seam Weld Cracking Susceptibility	Integrity Digs with Cracking Threats	Total Integrity Digs Analysed
1	SAV VER 323	Savona – Vernon 12"	Yes	Yes	50	92
2	VER PEN 323	Vernon – Penticton 12"	Yes	Yes	38	67
3	GRF TRA 273	Grand Forks – Trail 10"	Yes	Yes	138	228
4	OLI GRF 273	Oliver Y – Grand Forks 10"	Yes	Yes	79	163
5	PEN OLI 273	Penticton – Oliver Y 10"	Yes	Yes	13	23
6	TRA CAS 219	Trail – Castlegar 8"	Yes	Yes	11	76
7	KIN PRI 323	Kingsvale – Princeton 12"	Yes	Low	0	3
8	PRI OLI 323	Princeton – Oliver 12"	Yes	Low	2	12
9	YAH TRA 323	Yahk – Trail (ELK) 12"	Yes	Low	9	53
10	OLI PEN 406	Oliver – Penticton 16"	Low	Low	0	1
11	DUK SAV 508	Duke Tap – Savona C/S 20"	Low	Low	0	0
12	YAH OLI 610	Yahk – Rossland 24", Rossland – Oliver 24"	Low	Low	0	6

3

22. Reference: Exhibit B-1, page 40

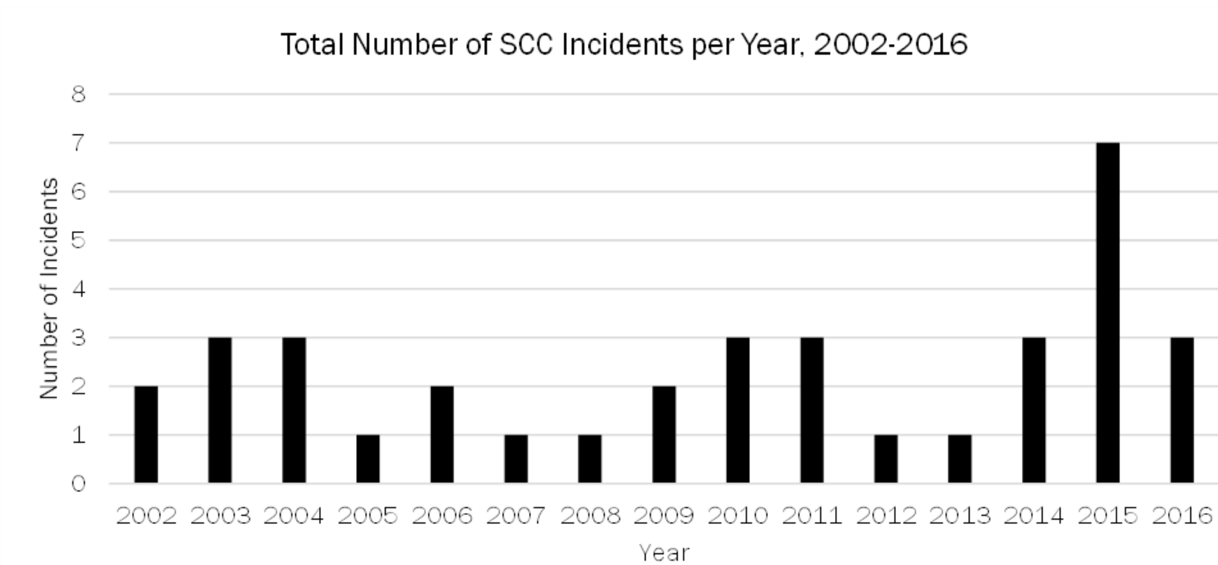
> First, JANA observes that industry failures have occurred on pipelines at operating stresses across the range of the operating stresses of the FEI susceptible transmission pipelines (i.e., from 12 to 72 percent of SMYS). Specifically, JANA's review of Pipeline and Hazardous Materials Safety Administration (PHMSA) / Industry Incident Data indicates that:
>
> - Approximately half of reported PHMSA SCC incidents through 2002-2016 occurred at 60 percent of SMYS or lower; and
> - Approximately one quarter of reported incidents occurred at 55 percent of SMYS or lower, with some circumferential SCC leaks occurring below 30 percent of SMYS (in presence of additional loading factors).

22.1 Please provide a chart depicting the total number of incidents in each year between 2002 and 2016.

<u>Response:</u>

JANA provides the following response:

The total number of SCC incidents reported in the PHMSA dataset between 2002 and 2016 are shown in the figure below.



23. Reference: Exhibit B-1, page 41

> The analysis estimated a range of potential time until failure from 5 to 85 years, indicating that there is the potential for SCC cracks to grow to failure under the operating conditions of the FEI system. While the lower bound timeframe of five years is considered highly unlikely (reflecting a combination of the longest, deepest crack with the lowest toughness pipeline), the analysis does indicate that SCC is a credible integrity threat that needs to be managed in a timely manner.
>
> [18] This analysis by Dr. Chen is included within Appendix B-1: Report: JANA Project 18-1651:P *Analysis of Cracking Threats in FEI Mainline Transmission Pipelines*. SCC crack growth analysis was applied to SCC crack features derived from a sample of FEI dig reports, actual FEI operating data and pipe material properties characteristic of the FEI system.
>
> [19] Fracture toughness is a measure of the resistance of a material to static or dynamic crack extension, used in the calculation of critical flaw size for crack-like defects.

23.1 Please provide a redacted copy of the report on the public record if feasible to do so.

Response:

Attachment 23.1 contains redacted copies of the following reports which were filed confidentially with the Application:

- Appendix B-1, "Analysis of Cracking Threats in FEI Mainline Transmission Pipelines"; and
- Appendix B-2, "Quantitative Safety Risk Assessment"

FEI's redactions have removed sensitive data and information regarding specific locations and quantified degrees of vulnerability along a pipeline, for the purposes of pipeline system security.

23.2 Please provide a probability curve for SCC cracks growing to failure from 5 years to 85 years and break out for the CTS and ITS systems if possible.

Response:

JANA provides the following response:

In addition to the analysis of observed industry failures, the purpose of the analysis was to assess if it is possible for SCC cracks to grow to failure in the FEI system. The analysis considered a range of scenarios in terms of crack size (depth and length), pipe fracture toughness, etc. that resulted in the range of projected potential time to failure. It is not possible to provide a probability curve for cracks growing to failure from 5 to 85 years as the actual distribution of cracks within the pipeline system is not known. This type of information could possibly be provided by EMAT ILI if a large number of cracks were found by the ILI tool.

24. Reference: Exhibit B-1, page 51

> To illustrate the potential consequences of a natural gas pipeline rupture, the following are examples experienced by North American natural gas transmission pipeline operators. The incidents described below that occurred in the United States are included due to their influence on gas transmission pipeline operator practice and the regulatory environment in both the United States and Canada. With respect to safety consequences, the diameter and operating pressure of a given pipeline correlate to the size of the potential affected area in the event of an ignited rupture failure event. This means that a smaller diameter pipeline will impact a smaller area than a larger diameter pipeline.

24.1 FEI provides multiple examples of ruptures that occurred. Please confirm that the measures proposed by FEI could potentially have prevented such ruptures if undertaken early enough.

Response:

Not confirmed. FEI provided the examples solely to illustrate potential consequences of a natural gas pipeline rupture. FEI did not intend for these ruptures to correlate with the mitigation proposed by the CTS TIMC Project.

FEI and the broader transmission pipeline industry review past failures for learnings that may be incorporated into integrity management programs. This approach fosters changes to industry standards and industry practice such as the widespread adoption of EMAT ILI technology.

24.2 Please describe how FEI will utilize the requested technology to inspect once it is installed. For example, will FEI conduct a transmission system overview sequentially reviewing its pipelines, or will it conduct simultaneous inspections of several or all transmission lines? Please explain.

Response:

Please refer to the response to RCIA IR1 14.2 for the proposed inspection schedule.

24.3 How quickly does the pig move through the transmission line such that an inspection is completed? Please provide various examples.

Response:

The optimal velocity of the EMAT ILI tool is between 1 and 2 metres per second. Assuming an average velocity of 1.5 metres per second, the table below provides a summary of the approximate duration required to complete an EMAT ILI inspection of the 11 CTS pipelines.

Pipeline	Length of Pipeline (km)	Approx. duration of EMAT ILI tool run (hours)
HUN ROE 1067	55.7	10.3
HUN NIC 762	56.4	10.4
LIV COQ 323	34.9	6.5
CPH BUR 508	17	3.1
TIL FRA 508	9.6	1.8
TIL BEN 323	5.9	1.1
LIV PAT 457	29.8	5.5
NIC FRA 610	24.3	4.5
ROE TIL 914	12.8	2.4
NIC PMA 610	4.9	0.9
TIL LNG 323	1.7	0.3

24.4 How long would it take for FEI to identify cracking either during or after an inspection is completed? Please explain.

Response:

FEI does not identify cracking during an inspection. Please refer to the response to CEC IR1 33.1 for the timelines required to identify cracking after the ILI run is complete.

25. Reference: Exhibit B-1, page 61

> The frequency of ILI tool runs in FEI's CTS system is commonly set at every seven years, but may be shorter if required. The run frequency is determined on a pipeline-by-pipeline basis by analysis of the run results and other factors including operating history, pipeline availability for ILI (i.e., scheduling factors), and industry practice. It is not possible for FEI to establish its initial frequency of EMAT inspection with complete certainty in the absence of baseline EMAT ILI and subsequent integrity dig program results, and the frequency could also change over time as the various inputs change.

25.1 Over what period of time does FEI expect it will have been able to complete an inspection of its entire CTS transmission system using the technologies requested in this application? Please explain why it is expected to take this time, and what are the limiting factors that result in the timelines – i.e. labour requirements, number of pigs available, time for the pig to move through a pipeline, etc.

<u>Response:</u>

FEI expects to complete its baseline EMAT ILI runs on the 11 CTS TIMC pipelines between 2024 and 2027 for the following reasons:

- **Seasonal windows:** Tool runs must be completed within certain seasonal windows to achieve the optimal tool velocities and collect good quality data.
- **Pipeline preparation:** While actual ILI runs may be completed in a single day, the pipeline being inspected must be cleaned prior to running the ILI tool to ensure dirt and debris in the pipeline does not damage the tool or compromise its performance. This process can take up to two weeks or longer to complete.
- **FEI resources:** Availability of Operations resources are a necessary consideration. FEI Operations is responsible for completing a range of other capital and maintenance work during the year, in addition to running ILI tools and performing the corresponding integrity digs.
- **Contractor resources:** Tools and tool vendors may not be available during the window FEI requires to run tools.

FEI's schedule for these EMAT ILI runs also reflects the identified hazard and risks of SCC on its system and other factors.

25.2 Once FEI has conducted a thorough inspection of its entire system, would FEI need to essentially recommence the same process immediately, such that there is continuous inspection or would FEI wait for particular period, i.e. the 7 years? Please explain.

Response:

The re-inspection cycle for each pipeline will be determined using the findings of the initial EMAT ILI run. As described in CEC IR1 25.1, FEI expects to complete the baseline EMAT ILI runs within a period of four years. FEI does not anticipate that it will need to recommence the same process immediately in the CTS; however, some pipelines may be re-inspected earlier than others depending on the findings of the initial EMAT ILI run.

25.2.1 Please provide a discussion relating the time frame it takes for a crack to develop and the expected inspection frequency.

Response:

Cracks can develop and grow over any time frame and, hence, crack analysis to establish integrity digs and re-inspection frequencies employs appropriate conservatism and line-specific inputs to ensure timely intervention such that potential cracks are found and repaired prior to growing to failure.

FEI will use a range of crack growth rates, informed by industry practice and the *CEPA Recommended Practice for Managing Near-neutral pH Stress Corrosion Cracking*, to assess the features found through EMAT ILI and to determine a re-inspection frequency for subsequent EMAT ILI. FEI typically inspects its pipelines on a 7-year cycle, unless the growth assessment or other line-specific considerations (such as an observed localized external stress) indicates earlier re-inspection is required.

25.3 Will FEI be providing the Commission with reports on the results of its ILI inspections on each or all of its CTS lines? Please explain why or why not.

Response:

A key outcome from FEI's EMAT ILI inspections is its determination of subsequent Integrity Digs. FEI currently provides Integrity Dig forecasts through Annual Reviews, including discussion of the drivers for digs such as inspection results pertaining to all ILI technologies including FEI’s current use of MFL and CMFL ILI tools and the adoption of EMAT ILI tools in the CTS pipelines.

26. Reference: Exhibit B-1, page 56

Table 4-1: Summary of Alternatives Evaluation

	Non-Financial Assessment	Technical Feasibility	Financial Assessment	Financial Feasibility
Alternative 1: SCCDA		Not Feasible		
Alternative 2: PRS		Not Feasible		
Alternative 3: HSTP		Not Feasible		
Alternative 4: EMAT ILI		Feasible		Feasible
Alternative 5: PLR		Potentially Feasible		Not Feasible
Alternative 6: PLE		Potentially Feasible		Not Feasible

26.1 Are the alternatives evaluated similar to those evaluated for the 29 transmission laterals for the Inland Gas Upgrade Project? Please explain how they are similar or different and why.

Response:

The alternatives evaluated in the CTS TIMC Project are similar to those evaluated as part of the Inland Gas Upgrade (IGU) Project, with differences in some alternatives as described below. The IGU Project evaluated alternatives for individual laterals whereas the CTS TIMC Project alternatives were evaluated for the system (all 11 pipelines).

- **Alternative 1: Stress Corrosion Cracking Direct Assessment (SSCDA)**

  This alternative is similar to the Modified External Corrosion Direct Assessment (ECDA) alternative evaluated under the IGU Project as it requires the same four steps:

  1. Pre-assessment;
  2. Indirect inspection;
  3. Direct examination; and
  4. Post assessment.

  The main difference between the SSCDA and Modified ECDA alternatives is that they are used to manage different integrity threats. SSCDA is used to manage stress corrosion cracking, whereas Modified ECDA is used to manage metal-loss external corrosion.

- **Alternative 2: Pressure Regulating Station (PRS)**

  This alternative is the same as the PRS alternative evaluated as part of the IGU Project.

- **Alternative 3: Hydrostatic Testing Program (HSTP)**

  This alternative is the same as the HSTP alternative evaluated as part of the IGU Project.

- **Alternative 4: Electro-magnetic Acoustic Transducer In-Line Inspection (EMAT ILI)**

  This alternative is similar to the ILI alternative evaluated as part of the IGU Project in that it proposes passing a data inspection device through the pipeline to identify and locate certain integrity threats. However, there are several key difference between the CTS TIMC and IGU projects as it relates to this alternative:

  1. **Tool sensor:** The sensor on the EMAT ILI tool is specifically designed to detect cracking in pipelines. The sensors on the ILI tools proposed under the IGU Project are not capable of detecting cracks.
  2. **Launcher and receiver barrels:** FEI runs other types of ILI tools in the 11 CTS TIMC pipelines. As such, the CTS TIMC Project proposes modifying the existing launchers and receivers to accommodate EMAT ILI tools, which are longer than the tools currently being run in these pipelines. The laterals considered under the IGU Project were not being in-line inspected prior to the Application. As such, the IGU's ILI alternative involved the installation of new launchers and receivers and the associated barrel isolation valves.
  3. **Flow control and pressure regulating stations:** The CTS TIMC Project proposes the construction of flow control stations to maintain the velocity of the EMAT ILI tools that do not have a speed control unit. EMAT ILI tools must travel at slower velocities than the tools proposed for use under the IGU Project. The scope of the CTS TIMC Project also includes the construction of pressure regulating stations (PRS) to facilitate pressure reductions on individual pipelines. These PRS's enable FEI to implement the required safety response in the event that a significant cracking threat is found. The CSA Z662 standard requires a more stringent safety response for a sharp feature like a crack than for a more typical blunt feature like corrosion.

- **Alternative 5: Pipeline Replacement (PLR)**

  This alternative is similar to the PLR alternative evaluated under the IGU Project as it involves replacing the existing pipeline(s) in their entirety. In Section 4.2.6 of the IGU Project Application, FEI stated that it would design the replacement pipeline with an operating stress less than 30 percent of SMYS to reduce the corrosion-related rupture potential. The PLR alternative evaluated under the CTS TIMC Project may or may not design the replacement pipelines with an operating stress less than 30 percent of SMYS due to different operational requirements between individual laterals and a transmission system.

- **Alternative 6: Pipeline Exposure and Recoat (PLE)**

  This alternative is similar to the PLE alternative evaluated under the IGU Project as it requires the same six steps:

  1. Expose the entire length of the pipeline;
  2. Remove the existing coating;
  3. Perform an inspection of the surface of the pipeline;
  4. Conduct repairs, as needed;
  5. Re-coat the pipeline; and
  6. Rebury the pipeline.

  In Section 4.2.2 of the IGU Project application, FEI stated that once the pipeline was recoated and reburied, it would be subject to future inspection via Modified ECDA which is a practice specific to external corrosion. In the case of the CTS TIMC Project, FEI would recoat with a coating that is non-susceptible to SCC.

26.2 Would any of the alternatives determined to be Not Feasible have been feasible on any significant portions of the CTS system? Please explain.

26.2.1 If yes, please identify which portions of the CTS system could have used a different alternative than that selected.

Response:

Please refer to the response to BCUC IR1 6.1.

26.2.1.1 Recognizing that FEI did not conduct a financial analysis of alternatives not deemed feasible, please provide a best estimate order of magnitude relationship between the cost of a different alternative for a specific portion of the CTS – i.e. 30% more? 1% less?

Response:

FEI evaluated the project alternatives first for technical feasibility, followed by financial feasibility. Alternatives 1, 2 and 3 were not technically feasible. As discussed in response to BCUC IR1 6.1, these alternatives are also not feasible when applied to sub-portions of the CTS.

To develop a best estimate order of magnitude for the other alternatives, the alternatives need to be scoped such that it could theoretically reduce the risk in an acceptable way. With that in mind, the following high-level scope would need to be considered:

- **Alternative 1**: Given the inability of SCCDA to reliably find cracking threats, FEI would be required to expose the pipelines in their entirety to understand cracking threats on its system. The resulting alternative would be similar to Alternative 6: PLE and would be expected to have a similar cost magnitude (see Table 4-4 of the Application).
- **Alternative 2:** The reduction in pressure on the CTS would result in a capacity shortfall. The lost capacity would need to be replaced through the installation of additional pipe. The resulting alternative would be similar to Alternative 5: PLR and would be expected to have a similar cost magnitude (see Table 4-4 of the Application).
- **Alternative 3:** A hydrostatic testing program would have similar elements as an EMAT ILI program, in that testing would be required to be completed on a recurring interval. However, FEI would also need to consider alternate ways to supply customers serviced by lines that do not have a parallel pipeline to maintain gas supply during testing. This would likely involve looping some pipelines and would make up a majority of the cost of the alternative. As such, if 25 percent of the system required looping, then the magnitude of costs would be in the hundreds of millions of dollars (assuming 25 percent of the cost of Alternative 5).

27. Reference: Exhibit B-1, page 56

> Based on an assessment using the non-financial criteria, three alternatives were screened out as not technically feasible because they were unable to be implemented on the overall CTS in such a way as to sufficiently mitigate cracking threats. Based on a financial assessment, two of the remaining three alternatives were screened out because they were not financially feasible due to high-level cost estimates approaching $2 billion, approximately six times the costs of the EMAT ILI alternative. EMAT ILI is the sole option which is both technically and financially feasible and is therefore the preferred alternative for the CTS TIMC Project.
>
> An exception to the above conclusion regarding EMAT ILI being the preferred alternative is for the Noon's Creek to Burrard 508 segment of the Cape Horn to Burrard 508 transmission pipeline, which does not have the gas flow conditions required to move an ILI tool through the pipeline.[35] As such, FEI selected the pressure regulating station (PRS) alternative to manage and mitigate cracking threats on this segment.

27.1 Did the project need to be similar for the entire CTS overall, or could FEI have conducted a mixed group of technologies as was provided in the IGU? Please explain.

Response:

Please refer to the response to BCUC IR1 6.1.

27.1.1 If the project could have been undertaken using different technologies, did FEI screen out any options where different technologies could have been employed, in order to use a system wide technology? Please explain.

Response:

FEI is unclear what CEC is referring to by "different technologies" in its question.

If CEC is referring to the alternatives other than EMAT ILI presented in the Application, then please refer to the response to BCUC IR1 6.1, which explains that the alternatives remain non-feasible for sub-portions of the CTS. On this basis, these different technologies were not screened out in order to use a system-wide alternative.

FEI is not aware of any different technologies beyond those presented in the Application that would address the integrity management objectives of the Project.

28. Reference: Exhibit B-1, page 61

At present, EMAT tools are technically feasible and sufficiently commercialized to be employed as a mitigation measure in pipelines down to a nominal pipe size of 10 inches. To implement an EMAT ILI program, the following system and process improvements would be required:

- Pipeline alterations: required to address locations where speed excursions[44] may occur and where the ILI tool may not be able to pass through the pipeline. Pipeline alterations generally consist of cutting out the heavy wall features (e.g., fittings, pipe, etc.) causing speed excursions and replacing with higher grade pipe with a wall thickness that matches the rest of the pipeline.

28.1 Please identify any technologies that FEI is aware of that are currently under development and might permit FEI to avoid pipeline alterations if they were used and/or trialled.

28.1.1 If FEI is able to identify any technologies that are currently under development, could FEI have potentially acquired any cost savings or benefits from these technologies? Please explain.

Response:

FEI is not aware of any technologies that are currently under development that would permit FEI to avoid the pipe alterations identified as part of the Application.

29. Reference: Exhibit B-1, page 68 and 72

Table 4-3: Summary of Alternatives Assessment

	Non-Financial			Financial
	Method Effectiveness	Implementation Complexity	Community and Environmental Impacts	Net Present Value
Alternative 1: SCCDA	×	✓	-	n/a
Alternative 2: PRS	✓	×	✓	n/a
Alternative 3: HSTP	-	-		n/a
Alternative 4: EMAT ILI	✓	✓	✓	✓
Alternative 5: PLR	✓	×	×	×
Alternative 6: PLE	✓	-	×	×

4.4.2 Alternative 2: PRS Leads to System Capacity Limitations

PRS can be highly effective in reducing the likelihood for SCC to cause an in-service pipeline rupture, as these SCC threats would instead be expected to result in leaks.

However, pressure reduction creates significant operational challenges when applied to FEI's CTS. Due to the interconnected nature of the 11 CTS pipelines identified as part of the TIMC Project, PRS is not viable when applied to the pipeline system because of capacity limitations. As described in Section 4.2.2, the PRS alternative involves permanently lowering the maximum operating pressure of a pipeline such that the resultant hoop stresses are reduced to below 30 percent of SMYS. The majority of pipelines in the CTS operate at hoop stress levels between 45 to 50 percent of SMYS and therefore, the maximum operating pressure of the CTS would need to be reduced by approximately 40 percent to achieve the desired stress levels. This would lead to a significant reduction in the capacity available to customers in the Lower Mainland and Vancouver Island.

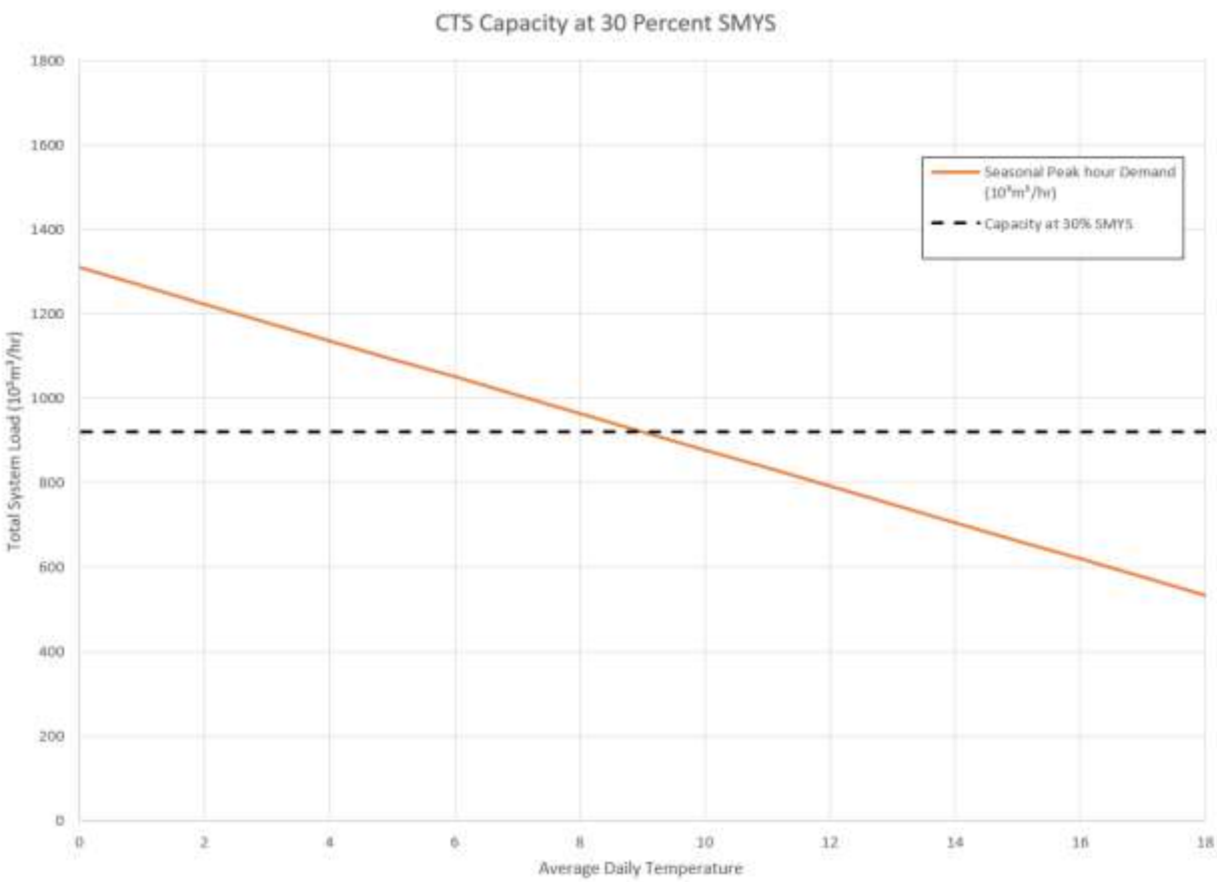
At reduced operating pressures, the capacity requirements of the system under current peak day demand cannot be met and extensive system looping would be required to meet current and future gas supply needs. FEI relies on CTS pipeline interdependencies to manage operational activities and ensure reliability and resiliency of the Coastal gas transmission and distribution system. FEI's operational flexibility would be impacted resulting in a reduced ability to plan and perform maintenance and construction work, establish line pack needs and move gas through the system.

With the exception of the Noon's Creek to Burrard 508 pipeline connecting the Noon's Creek Valve Assembly and decommissioned Burrard Thermal Plant in Coquitlam, implementation of PRS on the 11 CTS pipelines would result in FEI being unable to maintain reliable service to its customers. As such, PRS was deemed not technically feasible for system wide application to all 11 interconnected CTS TIMC pipelines and was not considered further in the evaluation process. The NOO BUR 508 exception is discussed in Section 4.7.

29.1.1 Please provide FEI's demand curve, and provide the point at which FEI would not be able to meet the current peak demand.

Response:

To achieve an operating stress less than 30 percent of SYMS, FEI would require the system to operate at a pressure of 2390 kPa. FEI's analysis of the CTS during the development of the TIMC CTS Application demonstrated that the capacity of the system under this condition is exceeded when the average daily temperature is between 9 degrees Celsius or cooler. Daily temperature averages lower than 9 degrees Celsius could occur any time in the period of September through May. The figure below shows the system demand versus temperature indicating the demand at which the CTS would have insufficient capacity if it were regulated to 30 percent of SMYS.



29.1.2 Would the issue of insufficient capacity occur along the entire line, or would this occur only in certain areas of a given pipeline? Please elaborate.

Response:

System capacity issues would occur across the entire CTS at multiple locations, and would occur at a system demand well below that currently occurring on a peak day. The CTS is designed to have capacity to meet peak demand with pressure at the Huntingdon Control Station at 3447 kPa, the minimum contract pressure provided at that point from the upstream Enbridge pipeline. To achieve an operating stress of 30 percent of SMYS, the reduction in system pressure required would be over 1050 kPa, from 3447 kPag to 2390 kPag, and would result in capacity issues at multiple gate stations across the system that would require upgrades to ensure reliable operation into the downstream distribution systems. Additionally, the inlet pressure to the V1 Compressor Station in Coquitlam that supplies FEI's Vancouver Island transmission system would fall below the minimum design pressure of 2070 kPa for most of the year requiring significant pipeline looping within the CTS to manage capacity needs.

29.1.2.1 If the insufficient capacity would only occur at certain portions of a pipeline, could FEI meet these demands in any other manner, such as using LNG?

Response:

As described in the response to CEC IR1 29.1.2, insufficient capacity to meet customer demand would occur for large portions of the year including the spring, fall and winter seasons at multiple locations across the CTS. As a result, peak shaving options like local LNG or CNG injection would not be a feasible solution for avoiding the otherwise extensive capacity upgrades that would be required to accommodate an operating pressure reduction on the system to achieve an operating stress below 30 percent of SMYS.

29.1.3 Please explain why additional looping is not feasible.

Response:

Pipeline looping was considered not feasible to allow operating the CTS at a reduced pressure because of the challenges associated with the extensive looping that would be required.

First, as discussed in the response to CEC IR1 29.1, operating pressures that would reduce pipeline stress to below 30 percent of SMYS creates capacity limitations for large portions of the year. This is based on current customer demand and does not consider future growth in demand or the possibility of large industrial demand being served through the system. Pipeline looping would require FEI to install new, large-diameter transmission lines from the Huntingdon Control Station in Abbotsford to near the Coquitlam Gate Station and another similar station location in Delta to recover capacity to serve current demand and future load growth. Similar to the Pipeline Replacement (PLR) alternative, pipeline looping would be rated a poor choice due to its cost, implementation complexity, and community, Indigenous, and environmental impacts.

Second, the CTS pipelines are located in highly urbanized areas and some statutory rights of ways (SRWs) are already occupied by multiple transmission pipelines. The installation of another transmission pipeline would be difficult and it may not even be possible while maintaining adequate clearance between existing pipelines in the SRW. Therefore, expansion of existing SRWs or acquisition of new land rights would likely be required.

30. Reference: Exhibit B-1, page 76

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

Based on the NPV of costs for the remaining three alternatives, it is clear that Alternatives 5 and 6 are cost prohibitive as compared to Alternative 4 and therefore are considered to be not financially feasible. FEI did not pursue Alternatives 5 and 6 further in the evaluation process.

30.1 Does FEI have a threshold at which it would consider EMAT ILI to have been cost prohibitive? Please explain.

30.1.1 If yes, please provide the threshold.

Response:

Please refer to the response to BCUC IR1 12.1.

30.1.2 What alternative actions would FEI have pursued if the EMAT ILI was deemed to be too costly? Please explain.

Response:

The EMAT ILI is not too costly. FEI has identified a credible cracking threat to its transmission pipelines, and has identified a proven, cost-effective, commercialized, and industry adopted mitigation in the form of EMAT ILI. As discussed in Section 4 of the Application, the only other meaningful alternative actions would be more costly for ratepayers.

31. Reference: Exhibit B-1, page 76

> With some system alterations, EMAT ILI can be implemented on the 11 CTS pipelines (with the exception of the tail end of the NOO BUR 508, further discussed in Section 4.7) and has less impact on the community or environment as compared to other alternatives. Details of the required alterations are set out in Section 5 of the Application. As detailed in Section 5.3.3, FEI

31.1 Will FEI experience cost or other benefits as a result of using EMAT ILI on all 11 CTS pipelines, as opposed to using differing options on different pipelines? Please explain.

31.1.1 Please quantify any cost or other benefits if possible.

Response:

By utilizing EMAT ILI on all 11 CTS pipelines, FEI will realize the following benefits:

- **Consistent approach to managing cracking threats:** EMAT is able to provide superior data with respect to cracking, including the size and location of features. By ensuring all pipelines have this same type of integrity data, FEI can monitor crack growth over time and utilize the data in its ongoing risk assessments.
- **Optimized response to cracking threats:** Ongoing ILI allows FEI to monitor the growth of features on an ongoing basis and optimize its response to these features, leading to optimization of resources and costs with respect to crack management integrity work.
- **Reduced costs compared to other feasible alternatives:** The only other technically feasible alternatives were Pipeline Replacement (PLR) and Pipeline Exposure and Recoat (PLE). As shown in Table 4-4 of the Application, the significant difference in the cost of these alternatives as compared to EMAT ILI (even if these alternatives were employed on a single pipeline), would make them significantly more expensive compared to implementing EMAT ILI on the same pipeline.

31.2 Can FEI expect to experience cost or other benefits as a result of making an application for the whole CTS (11 pipelines) vs breaking it into smaller CPCNs? Please explain.

Response:

FEI's rationale for combining all 11 CTS pipelines under a single CPCN application was because all of these pipelines are part of a single program to mitigate the identified cracking risk for pipelines meeting a common set of justification criteria, and will be executed and managed as one project. Therefore, presenting these pipelines as a single CPCN is efficient from a regulatory perspective and necessary to demonstrate the need and scope of the CTS TIMC Project so that a determination of public interest can be made with an understanding of the magnitude of costs and scope of work.

The need to monitor and mitigate the identified cracking risks and reduce the consequences of the associated risks is the same for each of the 11 CTS susceptible pipelines. The alternatives explored for each pipeline and the criteria used to determine the preferred alternative are also the same. The work for the Project will be executed as one program to obtain efficiencies and flexibility in scheduling. FEI believes that it is more informative for the BCUC to have all project information at once to be able to compare all feasible alternatives and evaluate the Project. Given the shared justification, alternatives analysis, and project execution strategy, FEI has treated the CTS TIMC Project as a single project in relation to the CPCN application.

FEI believes that it is more efficient to review all these shared aspects in one proceeding, rather than duplicate that effort in multiple regulatory proceedings. Please also refer to the response to BCUC IR1 4.5.

31.3 Could FEI have developed any cost or other benefit savings by including the next ITS TIMC CPCN in this CPCN application? Please explain.

Response:

FEI has not identified any cost or other benefit savings that would result from the inclusion of the ITS TIMC pipelines in this Application. The CTS and ITS are different systems based on: (1) the regions they operate within; (2) the stakeholders and Indigenous groups potentially affected; and (3) the operating parameters of the transmission pipelines within the systems. As such, the incremental resources and development work required to include the ITS component within this Application would remain relatively unchanged compared to FEI’s current process of filing separate CPCN applications.

Moreover, as explained in the response to BCUC IR1 4.3, the inclusion of some or all of the ITS TIMC pipelines in this Application would incur delays to the CTS TIMC Project, resulting in a delay in risk mitigation on the higher risk CTS pipelines. FEI’s decision to file the CTS and ITS TIMC CPCN applications separately allows risk to be mitigated in a timelier manner.

32. Reference: Exhibit B-1, page 84

> Accordingly, in April 2019, FEI hosted a workshop with interveners and BCUC staff. During the workshop, FEI and JANA jointly presented an overview of the TIMC project drivers and further described the Phase 1 CPCN development activities, including the collection of integrity data and the QRA process. At the conclusion of the workshop, FEI indicated that it intended to host a subsequent workshop in the fall of 2019 to provide the results of the Phase 1 QRA and the proposed scope of work for the project. This workshop was deferred until the spring of 2020 to allow additional time to complete the QRA; unfortunately, due to the COVID-19 pandemic, this workshop was ultimately cancelled. As discussed in section 1, FEI is proposing to have a

32.1 Please confirm that the workshop being referenced was conducted on May 13, 2021, and that the reference material is included in Exhibit B-4.

<u>Response:</u>

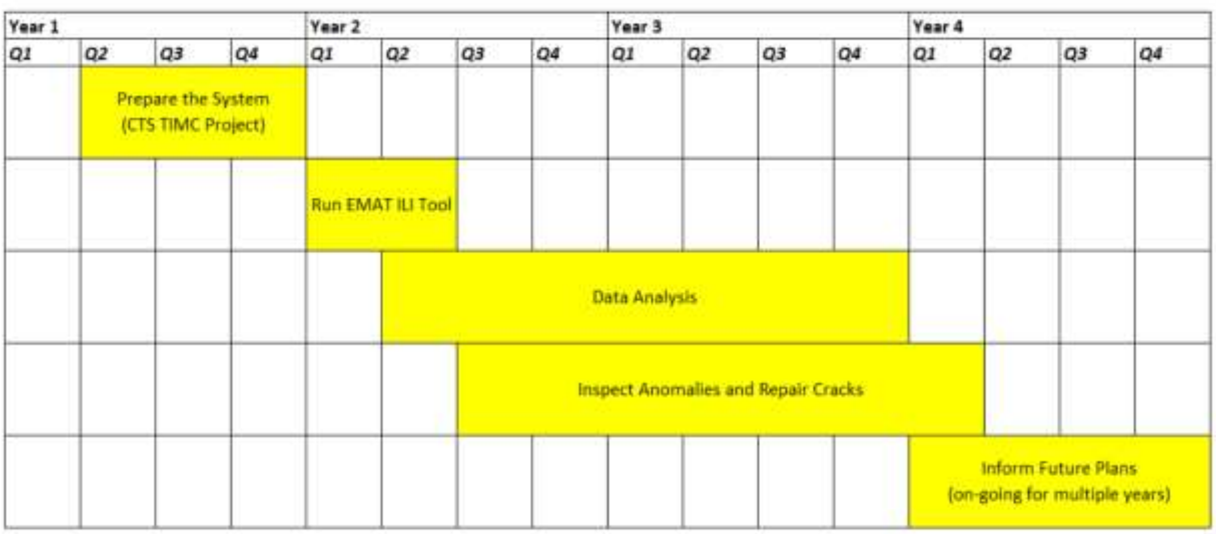
Confirmed.

33. Reference: Exhibit B-4, page 60

33.1 Please provide timelines for each of the identified activities.

Response:

The typical timelines for each activity are provided in the Gantt chart below. The actual timelines may vary for each pipeline based on availability of tools and resources and pipeline operating conditions. A brief description of each activity is also provided.



1. **Prepare the System:** Includes performing pipeline and facility alterations required to ready the system for EMAT ILI tool runs and facilitate post-EMAT ILI run actions.

2. **Run EMAT ILI Tool:** Includes cleaning tool runs to prepare the pipeline for the EMAT ILI tool, and the EMAT ILI tool run.

- *Note:* EMAT ILI tool runs on the 11 CTS pipelines will be completed over the multiple years and thus, may not occur directly after CTS TIMC Project construction (preparing the system).

3. **Data Analysis:** An iterative process performed in conjunction with inspection and repairs. The EMAT ILI vendor assesses tool data and FEI reviews the findings and identifies whether any digs are required. Dig information is fed back to the EMAT ILI vendor to refine the data analysis.
4. **Inspect Anomalies and Repair Cracks**: An iterative process performed in conjunction with data analysis; includes inspection and repair of features identified through the data analysis process.
5. **Inform Future Plans:** Including blind spot repairs, determination of EMAT ILI re-inspection interval, and the assessment of pipeline integrity data to determine areas requiring broader mitigation efforts.

33.2 Please describe the types of activities that would be included in 'Future Plans'. Do the 'Future Plans' include further inspections, reporting or other types of activities?

<u>Response:</u>

FEI's reference to "Future plans" in the Application includes the following types of activities which may take place:

- **Blind spot repairs:** As described in Table 5-15 of the Application, discrete projects will be developed to mitigate cracking at locations where the EMAT ILI tool data was compromised. Depending on the number of locations where this occurs and site-specific considerations, these projects may take multiple years to complete.
- **Determination of EMAT ILI re-inspection interval:** Once ILI data has been reviewed and validated, FEI will need to determine a re-inspection interval for each CTS pipeline.
- **Assessment of pipeline integrity data to determine areas requiring broader mitigation efforts:** Once the ILI data has been reviewed and validated, FEI may be required to undertake larger pipeline rehabilitation projects depending on the overall integrity of the pipeline with respect to cracking and other threats.

34. Reference: Exhibit B-1, page 76 and page 123 Table 6-4

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

Table 6-4: Financial Analysis of the Project ($millions)

Line	Particular	Project [a]	Reference (Confidential Appendix Financial Schedules)
1	Total Charged to Gas Plant in Service ($ millions)	124.600	Schedule 6, Line 35, less Table 6-4 Line 4
2	Total Project Deferral Cost	13.243	Schedule 9, Line 2 + Line 7
3	**Total Project Cost - Excluding Sustainment Capital ($ millions)**	**137.843**	**Sum of Line 1 & Line 2**
4	Sustainment Capital [b]	84.983	Schedule 6, Sum of lines 12 & 13, 2026-2090
5	**Total Project Cost - Including Sustainment Capital ($ millions)**	**222.826**	**Sum of Line 3 & Line 4**
6	Incremental Rate Base in 2026 ($ millions)	107.257	Schedule 5 Line 19 (2026)
7	Incremental Revenue Requirement in 2026 ($ millions)	11.588	Schedule 1 Line 11, (2026)
8	**PV of Incremental Revenue Requirement 70 Years ($ millions)**	**147.460**	**Schedule 10, Line 25**
9	Net Cash Flow NPV 70 Years ($ millions)	(4.718)	Schedule 11, Line 17
10			
11	Delivery Rate Impact in 2026 (%)	1.32%	Schedule 10, Line 28 (2026)
12	**Levelized Delivery Rate Impact 70 years (%)**	**0.94%**	**Schedule 10, Line 32**
13	Levelized Delivery Rate Impact 70 years ($/GJ)	0.042	Schedule 10, Line 45

34.1 Please provide any updates to the above tables if any have occurred since the application.

Response:

FEI confirms there have been no updates to Table 6-4 since filing the Application.

34.2 Does the NPV of Capital costs of $225 (Alternative 4) include sustainment capital with a cost of $222.826? Please explain.

Response:

No, the NPV of Capital Costs of $225 million for Alternative 4 in Table 4-4 does not include the Sustainment Capital of $84.983 million in Line 4 of Table 6-4.

The NPV analyses presented in Table 4-4 are for the purpose of alternative analysis only based on the direct capital and O&M costs of the identified alternatives. The direct costs used in the alternative analysis in Table 4-4 did not include contingency, AFUDC, or future estimates for Sustainment Capital.

The financial analysis completed in Section 6 and presented in Table 6-4 of the Application is for the preferred alternative with a total Project cost that includes contingency, AFUDC, and future estimates for Sustainment Capital.

34.3 Please provide the calculation of the NPV values for Alternative 4 in Table 4-4 and the assumptions used on the public record, or explain why they should be kept confidential.

<u>Response:</u>

The calculation and assumptions (capital and O&M estimates) for the NPV values of Alternative 4 in Table 4-4 were filed in Confidential Appendix G-1. The NPV analysis shown in Section 4 also includes the future estimates for integrity management activities. FEI notes NPV calculations for the alternative analysis do not include contingency, AFUDC, and future estimates of Sustainment Capital.

FEI requested Appendix G be filed confidentially because it includes estimates of material costs as well as the direct and indirect construction costs. The estimates have been filed confidentially on the basis FEI may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work were disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding. This approach is consistent with past CPCN applications filed by FEI.

35. Reference: Exhibit B-1, page 85 and 86

5.3.2 Project Development Costs Were Necessary and Are Consistent with Original Forecasts

Table 12-1 from the Annual Review for 2019 Delivery Rates application (reproduced below), provided a forecast of development cost expenditures related to Phases 1 and 2:

Table 12-1: CPCN Development Costs ($000s)

Line No.	Phase	2018	2019	2020	Total
1	Phase 1	$ 5,680	$ 5,710	$ 230	$ 11,620
2	Phase 2	-	19,000	11,000	30,000
3					
4	Total	**$ 5,680**	**$ 24,710**	**$ 11,230**	**$ 41,620**

The total actual and projected development costs for the CTS TIMC project are $30.824 million to be incurred to the end of 2021, compared to the original estimated CPCN application development costs of $41.620 million for the entire TIMC project, as shown in Table 12-1 above. FEI notes, however, that the development costs for the future ITS TIMC CPCN application will continue to be collected in the deferral account until submission and a decision from the BCUC on that application. The costs for the ITS TIMC are expected to be substantially lower than those recorded to date, as the only items that will be incurred for this future application will be

35.1 Please confirm or otherwise explain that FEI can expect significant cost savings for the ITS TIMC application relative to the CTS application.

<u>Response:</u>

FEI confirms that the development costs for the ITS TIMC application will be lower than that of the CTS TIMC Application. This is primarily due to the inclusion of the baseline QRA and EMAT Pilot Project costs in the CTS TIMC Project development costs as reflected in Table 6-1 of the Application.

35.2 What portion of the original CPCN development costs of $41.6 million did FEI originally expect would be attributable to the CTS and what portion was attributable to the ITS portion of the entire project? Please provide any breakdown that FEI has available from its original estimate.

<u>Response:</u>

Please refer to the response to BCUC IR1 26.1.

35.3 Please provide FEI's best estimate of the development costs that will be required for the ITS TIMC CPCN.

Response:

Please refer to the response to BCUC IR1 26.1.

35.4 To the extent that FEI expects that the total costs will differ from the original forecast, please explain why, and provide quantification for each reason.

Response:

Please refer to the response to BCUC IR1 26.1.

36. Reference: Exhibit B-1, page 104

5.6 *Project Schedule*

The preliminary Project schedule is based on receiving BCUC Project Approvals by Q1 2022 and an assumed construction start of Q1 2024. The schedule considers performance of the site work between the months of April and October 2022. Until BCUC Approval is received, FEI plans to utilize this time to complete all permitting and consultation activities. FEI, in conjunction with the Project FEED engineering consultant (Stantec), developed the Project construction schedule. The Basis of schedule can be found in Appendix D-3.

The Project activities will be subdivided into six main groups as follows:

1. Project Services;
2. Permitting;
3. Engineering detailed design;
4. Contract Award / Procurement / manufacturing;
5. Pipeline Construction; and
6. Facilities Construction.

Table 5-9: Project Schedule

Activity	Date
CPCN Preparation	Jun 2020 to Jan 2021
CPCN Filing	Feb 2021
CPCN Approval	Q1 2022
Contractor Selection and Award	
Engineering Services Contractor Selection and Contractor Negotiation	Sep 2021 to Dec 2021
Construction Contractor Selection and Contract Negotiation	Apr 2023 to Aug 2023
Permitting for CTS TIMC	
Municipal and Community Consultation	Nov 2020 to Nov 2024
Indigenous Communities Consultation	Nov 2020 to Dec 2023
OGC Permits	Jul 2022 to Jan 2024
ALC Permits	Jun 2022 to Jan 2024
Federal Permits (Vancouver Fraser Port Authority, Transport Canada, Department of Fisheries and Oceans)	Jun 2022 to Jan 2024
Railway Crossing Permits	Jun 2022 to Jan 2024
Ministry of Transportation and Infrastructure Permits	Jun 2022 to Jan 2024
Municipal and Regional District Permits	Jun 2022 to Jan 2024
Utility Permits & Approvals	Jun 2022 to Jan 2024
Environmental and Archaeological Permits	Jul 2022 to Jan 2024
CTS TIMC CONSTRUCTION	
Land Owner consultation	Apr 2023 to Aug 2023
Secure Detail Design Engineering Consultant	Feb 2022
Engineering Detailed Design	Mar 2022 to Jan 2023
Procurement and Manufacturing	
Long Lead Items	Jun 2022 to Mar 2023
Facilities, Electrical, and Instrumentation	Mar 2023 to Aug 2023
Fabrication	Oct 2023 to Jul 2024
Mobilization to Site	Feb 2024
Site Installation	
Construction	Mar 2024 to Nov 2024
Restoration and Demobilization	Mar 2024 to May 2025
Project Close Out	Dec 2024 to Nov 2025

36.1 Please update the project schedule to the extent that any changes have occurred or are forecast since the application was submitted.

Response:

No changes have occurred to the Project schedule since the Application was submitted in February 2021.

37. Reference: Exhibit B-1, page 120 and page 122 and 123

6.1 *INTRODUCTION*

The CTS TIMC Project has a Total Cost Estimate of $137.8 million. This section describes the actual and forecast costs in the TIMC Development Cost deferral account, provides a breakdown of the Project costs, summarizes the financial analysis, and details the accounting treatment of capital costs and rate impact of the Project.

Table 6-2: Summary of Forecast Capital and Deferred Costs ($millions)

Line	Item	2020 $	As-Spent	Reference
1	Pipeline Construction Costs	35.895	38.930	Section 5.4 and Confidential Appendix D-4
2	Stations Construction Costs	36.470	39.266	Section 5.5 and Confidential Appendix D-4
3	Project Management and Owner's Costs	15.247	16.166	Section 5.10
4	Subtotal Project Capital Cost	87.613	94.362	
5	Contingency	14.691	15.624	Section 5.10.2 and Confidential Appendix E-3
6	Subtotal Contingency	14.691	15.624	
7	CPCN Application Costs	0.500	0.510	Section 6.3.2
8	Preliminary Stage Development Costs	18.366	18.436	Section 6.3.2
9	Pre-Construction Development Costs	11.847	11.878	Section 6.3.2
10	Subtotal Development and Deferral Costs	30.714	30.824	Table 6-1, Row 1, Col 7
11	AFUDC		6.150	Table 6-3, Row 21, Col 5
12	Tax Offset		(9.117)	Table 6-3, Row 21, Col 4
13	**Total Project Cost**	**133.018**	**137.843**	Table 6-3, Row 19, Col 7

Table 6-4: Financial Analysis of the Project ($millions)

Line	Particular	Project [a]	Reference (Confidential Appendix Financial Schedules)
1	Total Charged to Gas Plant in Service ($ millions)	124.600	Schedule 6, Line 35, less Table 6-4 Line 4
2	Total Project Deferral Cost	13.243	Schedule 9, Line 2 + Line 7
3	**Total Project Cost - Excluding Sustainment Capital ($ millions)**	**137.843**	**Sum of Line 1 & Line 2**
4	Sustainment Capital [b]	84.983	Schedule 6, Sum of lines 12 & 13, 2026-2090
5	**Total Project Cost - Including Sustainment Capital ($ millions)**	**222.826**	**Sum of Line 3 & Line 4**
6	Incremental Rate Base in 2026 ($ millions)	107.257	Schedule 5 Line 19 (2026)
7	Incremental Revenue Requirement in 2026 ($ millions)	11.588	Schedule 1 Line 11, (2026)
8	**PV of Incremental Revenue Requirement 70 Years ($ millions)**	**147.460**	**Schedule 10, Line 25**
9	Net Cash Flow NPV 70 Years ($ millions)	(4.718)	Schedule 11, Line 17
10			
11	Delivery Rate Impact in 2026 (%)	1.32%	Schedule 10, Line 28 (2026)
12	**Levelized Delivery Rate Impact 70 years (%)**	**0.94%**	**Schedule 10, Line 32**
13	Levelized Delivery Rate Impact 70 years ($/GJ)	0.042	Schedule 10, Line 45

37.1 Please confirm that the Total Cost Estimate referenced in the introduction of Section 6.1 of $137.8 million relates only to Forecast capital and deferred costs as shown in Table 6¬2, whereas the Total Project cost including sustainment capital is $222.826 million as shown in Table 6-4.

Response:

The total Project cost estimate of $137.8 million referenced in the introduction of Section 6.1 of the Application equals the forecast capital and deferred costs as shown in Table 6-2.

The total Project cost including Sustainment capital of $222.826 million on Line 5 of Table 6-4 is the total capital costs included in the 70-year financial analysis and includes the same $137.8 million of project cost from Table 6-2, plus the estimated future Sustainment capital added to the financial analysis for the 70-year period.

38. Reference: Exhibit B-1, page 124

6.5.2 Rate Impact

As discussed above, FEI expects to complete construction of the Project in 2024 with final cloe out activities in 2025, such that the last of the assets enter rate base on January 1, 2026. Combined with the amortization of the deferral account costs beginning in 2022, the incremental impact to customer delivery rates will change each year from 2022 to 2026 as set out in the table below. Table 6-5 sets out the annual delivery rate impact compared to the 2021 non-bypass revenue requirement and the incremental annual delivery rate impact in percentage terms for years 2022 to 2026 of the Project.

Table 6-5: Summary of Rate Impact of the Project

Project Rate Impacts	2022	2023	2024	2025	2026
Annual Delivery Margin, Incremental to 2021 Approved, Non-Bypass ($millions)	10.726	11.004	10.691	11.461	11.588
% Increase to 2021 Approved Delivery Margin, Non-Bypass	**1.22%**	**1.25%**	**1.22%**	**1.30%**	**1.32%**
Incremental % Delivery Rate Impact (Year-over-Year)	**1.22%**	**0.03%**	**-0.04%**	**0.09%**	**0.01%**
Average Annual % Delivery Rate Impact (5 years, 2022-2026)	0.26%				
Average Annual Delivery Rate Impact (5 years, 2022-2026), $/GJ	0.013				
Cumulative % Delivery Rate Impact (5 years, 2022-2026)	1.32%				
Cumulative Delivery Rate Impact (5 years, 2022-2026), $/GJ	0.066				

The Project will result in an estimated cumulative delivery rate impact of 1.32 percent by 2026 when all construction is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the five years from 2022 to 2026 is estimated to be 0.26 percent annually or $0.013 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $1.19 per year over the five years, or $5.96 cumulatively by 2026.

38.1 Does FEI consider the annual rate impacts to be de minimis or did FEI consider rate smoothing options to avoid a rate reduction in 2024 followed by a larger rate impact in 2025? Please explain.

<u>Response:</u>

The CTS TIMC Project is planned to be completed in phases with assets entering rate base between 2022 and 2026. The rate reduction in 2024 reflects that there are no additions to rate base forecast to occur in that year. The delivery rate impacts shown in Table 6-5 are estimates associated with the CTS TIMC Project only, and are incremental to any delivery rate impacts due to FEI's revenue requirements for those specific years. FEI did not consider, nor is it reasonable to consider, a rate smoothing option at this time. The actual delivery rate impact for FEI in 2024 or 2025 will not be dependent on the CTS TIMC Project alone. Various factors will affect FEI's revenue requirement in those years including the demand forecast, offsetting revenues, taxes, O&M expenses, and capital additions (including the CTS TIMC Project, if approved). It is unknown at this time what the overall delivery rate impacts may be in 2024 and 2025, and FEI will consider and propose rate smoothing options, if necessary, in FEI's future annual review proceedings for delivery rates.

1 **39. Reference: Exhibit B-1, page 125 and Appendix H page vi and page 47**

7. ENVIRONMENT AND ARCHAEOLOGY

7.1 *INTRODUCTION*

FEI is committed to delivering safe and reliable energy in an environmentally responsible manner to all the communities that it serves. Based on its preliminary environmental and archaeological assessment, FEI expects that the Project's scope, which is confined to existing rights of way and facilities, will have low to moderate environmental and archaeological impacts.

The Environmental Overview Assessment (EOA) of the Project concludes that the environmental risk of the Project is low to moderate (Appendix H). FEI will mitigate the potential environmental impacts of the Project through the implementation of standard best management practices and mitigation measures. FEI will also minimize the impacts to construction timelines and costs resulting from encountering species at risk, fish habitat, or contaminated soil or groundwater through additional investigations during the detailed engineering phase prior to
2 construction.

Environmental and land use constraints are applicable to 9 of the 13 events and seven of the 13 facilities. Soil handing procedures are proposed as a mitigation measure to maintain soil capability for events in the Agricultural Land Reserve. This soil handling procedure is also recommended for one area that supports plants indicative of a provincially listed ecological community. Where work for the CTS TIMC Project could affect trees, hydrovacing under the supervision of a certified arborist is recommended. Noxious weed control is also recommended for all relevant events and facilities. Wildlife and wildlife habitat mitigation measures proposed include avoiding work in wildlife habitat, conducting pre-construction nest surveys if working during the bird nesting period (at relevant sites), and including wildlife salvage for work that may directly affect amphibians, small mammals of conservation concern, or reptiles. Avoiding or reducing work in watercourses is recommended to mitigate potential impacts on fish and fish habitat. Construction monitoring, erosion and sediment control, and developing a spill response plan are proposed to protect fish habitat and water quality. Soil characterization sampling is recommended for soils that will be disposed after hydrovac activities since the soil properties at many events and facilities are not known. Visual or olfactory indications of contamination should prompt a procedure for halting work and soil testing. After implementation of the proposed mitigation measures, the impact of the CTS TIMC
3 Project on environmental and land use resources is anticipated to be low to moderate.

5.0 Potential Environmental Effects, Risks, and Proposed Mitigation Measures

The CTS TIMC Project may have adverse effects on environmental resources. Potential environmental effects were identified when an environmental resource that is likely present in one or more of the events (as identified in Section 3.0) may be adversely affected directly or indirectly by CTS TIMC Project activities (as detailed in Table 2) within the short-term (immediately after completion of CTS TIMC Project activities) or medium-term (within one year of the completion of CTS TIMC Project activities). The qualitative assessment of residual risk (the potential effect of the CTS TIMC Project on the environmental resource) has been categorized as one of the following:

- Negligible: residual effects are not detectable.
- Low: residual effects are detectable, but well within the range of expected natural variation or below regulatory limits. environmental and/or regulatory limits.
- Moderate: residual effects are detectable and may approach upper regulatory limits or near the limits of expected natural variation.
- High: residual effects are beyond regulatory limits or beyond natural variation.

After implementation of the proposed mitigation measures (Table 23), the impact of the CTS TIMC Project
4 on environmental and land use resources is anticipated to be low to moderate

39.1 Please confirm or otherwise explain the CEC's understanding that where the impacts on the environment could be considered as moderate, the project could approach the upper bounds of the regulatory limit after all mitigation measures have been put in place.

Response:

CEC's understanding is correct, with the exception that potential impacts are not on the environment as a whole, but on individual and localized components of the environment (e.g., clearing of wildlife habitat and riparian habitat for temporary workspace). It should be noted that the definition of "moderate risk" is still within regulatory limits and within permissible natural variation.

40. Reference: Exhibit B-1, page 125

> FEI assessed the Project for high-level archaeological constraints in an Archaeological Constraints Report (ACR), included as Appendix I. The ACR concluded that the events and facilities may have elevated archaeological potential, with the exception of Fraser Gate Station which has low archaeological potential. No registered archaeological or heritage sites overlap with the Project footprint. As recommended by its archaeological consultant and to further assess the Project's potential archaeological impacts, in 2021 FEI will be conducting an Archaeological Overview Assessment (AOA) to determine archaeological potential, and an Archaeological Impact Assessment (AIA) for areas assessed as having elevated or high archaeological potential in the AOA. The AIA will provide a detailed assessment to allow for development of site-specific mitigation strategies to offset any potential impacts associated with the Project. If the results of the AIA determine that work is to take place in proximity to archaeological sites, monitoring during excavation works will be conducted, as per the recommendations of the archaeologist.

40.1 Will FEI conduct the 2021 AOA or will FEI outsource this report?

40.1.1 If FEI outsources the work, which company does FEI expect to use, and why?

<u>Response:</u>

The AOA is currently being undertaken by FEI's external consultant (Stantec) and will be sent to Indigenous groups for review before finalization. Stantec's professional archaeologists have extensive experience in the Lower Mainland, and have successfully worked with FEI on several other major projects.

41. Reference: Exhibit B-1, page 128-129

7.2.1.2 *Contaminated Sites*

Locations where there is a medium to high potential for encountering soil or groundwater contamination within the Project footprint may impact the Project's construction cost, and schedule. These areas are defined as Areas of Potential Environmental Concern (APEC)s.

Five APECs were identified in the contaminated sites study area and are summarized in the EOA (Appendix H) and in Table 7-2 below. FEI has not yet analysed soil used as fill on the

exiting right-of-way for contamination. Prior to or during construction, these soils will be assessed to assist in identification of appropriate disposal facilities.

Table 7-2: Registered Contaminated Sites and APECs Overlapping with Project Components

Pipeline	APEC Address	Distance from Event	Description
HUN NIC 762, Event 41	9470 192 Street, Surrey	Onsite	Large commercial vehicle storage
TIL FRA 508, Event 1	7389 River Road, Delta	Onsite	Husky fuel service station 2014: waste generator (fuel)
TIL FRA 508, Event 1	34 – 7621 Vantage Way, Delta	35 m southwest	Dry-cleaning facility
CPH NOO 508, Event 14	775 Mariner Way, Coquitlam	15 m southwest	Fire station
TIL LNG, Tilbury LNG Plant	7651 Hopcott Road, Delta	Onsite	Natural gas processing 2014: further investigation required by BC Ministry of Environment and Climate Change

FEI will undertake further assessment of APECs during the detailed engineering phase of the Project to minimize the risk they may pose to the Project's construction costs and schedule.

41.1 Please provide high-level estimates of the cost for remediating each site.

<u>Response:</u>

FEI's responsibility for contaminated site remediation would involve the removal of contaminated soil, if encountered, from its rights-of-way and disposal at an off-site regulated disposal facility. FEI is not required to remediate contamination beyond the construction footprint. The total estimated cost of contaminated soil disposal provided in the Class 3 estimate is approximately $200 thousand.

41.2 Which party would normally be responsible for remediating contaminated sites? Please explain.

Response:

The *Environmental Management Act* (EMA) and the Contaminated Sites Regulation (CSR) incorporate the "polluter-pays" principle. Individuals who are responsible for contamination are "responsible persons" and they are considered liable for remediation. Responsible persons can include current and previous property owners or operators. However, if the site is not considered high risk under EMA/CSR, then there is no regulatory requirement for the responsible person to remediate the site.

41.2.1 If the party such as a Husky Station would normally be required to remediate their own site, does FEI intend to recover costs from these landowners? Please explain why or why not.

Response:

If the site is not considered high risk under the EMA or the CSR, then there is no regulatory requirement for Husky or any other responsible person to remediate their site. FEI will remove contaminated soil from the rights-of-way, if encountered, to facilitate the Project because the EMA/CSR does not allow re-use of contaminated soil.

41.2.2 Has FEI contacted the landowners with contaminated sites? Please explain.

41.2.2.1 If yes, please briefly describe the communications between the parties.

41.2.2.2 If no, please explain why not.

Response:

The two Areas of Potential Environmental Concern (APECs) that are listed on the contaminated sites registry are the Husky fuel station and the Tilbury LNG plant. The other three APECs are not listed on the site registry, and are only considered to be areas that could potentially be contaminated due to present or historic land use. To date, FEI has not communicated with any of the landowners with regard to potential contamination. FEI plans to undertake sampling on its rights-of-way during detailed design of the Project. If contamination is encountered and it is deemed to be high risk under the EMA or the CSR, then direct communication with the landowner will occur.

42. Reference: Exhibit B-1, page 130

> **7.2.1.4 *Vegetation***
>
> Vegetation resources including plant species at risk, ecological communities at risk, and noxious plant species were reviewed as a part of the EOA. The following vegetation resources were identified:
>
> - One plant species at risk with potential to occur in or adjacent to the Project study area;
> - One ecological community at risk with potential to occur in or adjacent to the Project study area; and
> - Six noxious plant species with potential to occur or having mapped occurrences within the Project study area.

42.1 Please provide an estimate to remediate each of the sites with noxious weeds.

<u>Response:</u>

FEI included approximately $6 thousand in the cost estimate for the control of noxious weeds. A more detailed and accurate cost will be developed during detailed design based on field-checked locations of noxious weeds.

42.2 Are the noxious weeds likely to be encountered on land owned by others? Please explain and provide a table such as that provided for Contaminated sites.

42.2.1 If yes, is the landowner responsible for removing noxious species? Please explain.

42.2.1.1 If yes, does FEI expect to recover costs from these landowners? Please explain why or why not.

<u>Response:</u>

As described in the response to BCUC IR1 42.1, FEI will undertake field-checks for noxious weeds at Project sites. Some Project sites are owned by FEI, and other sites are located in rights of way on lands owned by others. The *Weed Control Act* RSBC1996 c. 487, imposes a general requirement on FEI to control noxious weeds on lands it owns and on its rights-of-way. Cost recovery in any particular situation depends on the facts, but in general, FEI would not recover the cost of noxious weed management on rights-of-way from landowners.

42.2.2 Has FEI contacted landowners with noxious weeds? Please explain.

42.2.2.1 If yes, please briefly describe the communications between the parties.

42.2.2.2 If not, please explain why not.

<u>Response:</u>

FEI has not yet contacted landowners with noxious weeds. If noxious weed management is required on the rights-of-way, then the landowners will be contacted prior to construction.

FEI does not intend to initiate discussions regarding noxious weeds and the need for treatment until after the pre-construction site visits have occurred confirming if noxious weeds are present. These site visits are expected to be scheduled in the spring-summer of 2023.

43. Reference: Exhibit B-1, page 140

> **Customer Notifications**
>
> FEI will notify all gas customers of the Project, including associated rate impacts, using a number of communication methods including bill inserts, the Accounts Online payment portal and as part of e-bill emails, FEI's website, and/or the Project webpage. FEI is in the process of notifying customers about associated rate impacts. Residential and small business gas customers will receive notifications in February 2021, with all remaining gas customers receiving notifications shortly thereafter.

43.1 Does FEI typically notify customers about 'associated rate impacts' prior to BCUC approval of its CPCN applications?

Response:

Yes, as part of its consultation activities FEI notifies all customers of the potential rate impacts associated with its projects that require CPCN applications. These notifications occur in various forms in advance of the BCUC's decision on the project application.

For the CTS TIMC Project, FEI used the following communication material to notify all gas customers about the project scope and potential rate impacts:

- **Webpage:** In October 2020, a dedicated project webpage was launched on FEI's Talking Energy website[7]. The webpage, which is updated as new project information becomes available, states:[8] "Rate impacts are estimated and have not yet been approved by the BCUC."
- **Bill insert:** A bill insert was distributed to all FEI gas customers in our February 2021 and March 2021 billing cycles. The insert states that project costs and associated rate impacts are "estimated."

43.2 Is FEI advising customers that the associated rate impacts are preliminary and not yet approved? Please explain.

Response:

Please refer to the response to CEC IR1 43.1.

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7 www.talkingenergy.ca/transmissionupgrades.

8 www.talkingenergy.ca/project/transmission-system-upgrades?utm_campaign=transmissionsystemsupgrade&utm_source=collateral&utm_content=transmissionupgrades#q-and-a.

44. Reference: Exhibit B-1, page 143

> **8.2.5.2 *Consultation to Date with Residents and Businesses Along the Rights of Way***
>
> As discussed in Section 8.2.3, FEI started consultation with residents and businesses along the rights of way in October 2020. On October 21, 2020, three residents and seven businesses along the rights of way and in direct proximity to worksites were mailed project information letters. A copy of the letter to property owners along the right of way is included as Appendix J-6.
>
> Follow-up telephone calls were made to affected residents and businesses on October 29 and October 30, 2020, confirming they received the letter, gathering feedback and addressing any outstanding concerns. The residents and businesses contacted have not raised any concerns at this stage. Feedback received is included as part of the consultation log (Appendix J-2). FEI will continue to consult with residents and businesses along the rights of way throughout the lifecycle of the Project.

44.1 Were only 3 residents and 7 businesses situated along the Project's rights of way affected?

44.1.1 If no, please explain why FEI did not provide information letters to all residents and businesses along the Project's rights of ways, and why they selected this group for this form of contact.

<u>Response:</u>

FEI only identified three residents and seven businesses along the rights of way and in direct proximity to worksites. As outlined in Section 8.2.5.2 of the Application, these residents and businesses were mailed project information letters and were provided with follow-up phone calls. As outlined in Section 8.2.5.3 of the Application, FEI also identified approximately 210 residents and businesses nearby the rights of way and worksites. These residents and businesses were also mailed project information letters.

Attachment 23.1

(accessible by opening the Attachments Tab in Adobe)