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April 20, 2023

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
Vancouver Centre II
2900 – 733 Seymour Street
Vancouver, BC
V6B 0S6

Attention: Christopher P. Weafer

Dear Christopher Weafer:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 2

On September 20, 2022, FEI filed the Application referenced above. In accordance with the further regulatory timetable established in British Columbia Utilities Commission Order G-48-23, FEI respectfully submits the attached response to CEC IR No. 2.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Parties

41. Reference: Exhibit B-7, CEC 1.2.1

2.1 Please discuss whether or not FEI attempted, and/or has been able, to secure reduced pricing in any capacity as a result of addressing more than one transmission system over a short period of time.

2.1.1 If FEI did not attempt to secure reduced pricing from its suppliers due to the large size of the two projects, please explain why not.

2.1.2 If FEI did secure reduced pricing from any of its suppliers, please provide details and quantification of the cost reductions.

2.1.3 If FEI attempted to secure reduced costing from its suppliers, but was unable to do so, please explain why it was unsuccessful.

Response:

While the cost estimate provided for the ITS TIMC Project does not include any reduced pricing from FEI's suppliers or service providers, during the execution phase of the Project, FEI will seek to secure reduced pricing from its suppliers for materials and services to address projects on more than one transmission system over a short period of time. FEI's procurement practices are performed ethically and in accordance with prudent business practices to achieve the greatest overall value for the project(s) requirements. Further, whenever possible, FEI consolidates requirements across projects and utilizes existing agreements to achieve the greatest overall value for the project(s). FEI's procurement practices include working with vendors and manufacturers through a competitive bid process.

41.1 Please describe other occasions in which FEI has been able to secure reduced pricing to address projects on more than one transmission system over a short period of time.

Response:

While FEI was unable to identify an example of reduced pricing for work over multiple transmission systems (e.g., ITS and CTS), FEI was able to secure competitive pricing from suppliers or service providers during the execution of the Inland Gas Upgrade (IGU) Project for work on more than one lateral. For context, the IGU Project was broken into four distinct phases. During the first phase in 2020, the project team went through a competitive bid process for services and materials and awarded based on a technical and commercial evaluation. The awarded contracts secured the most cost competitive pricing and achieved the greatest overall value for work completed on multiple laterals on the ITS. This approach has been completed for the subsequent three phases for the IGU Project.

41.2 Please provide quantitative estimates of the price reductions that FEI expects can be achieved as a result of seeing reduced pricing on 'more than one transmission system over a short period of time'.

Response:

FEI does not have sufficient information at this time to provide the requested information. In particular, the estimates requested will vary based on future market conditions – which will be clearer after the Project is approved and its design is complete.

41.3 Will FEI provide adjusted cost estimates to the Commission, if it is able to secure such price reductions? Please explain why or why not.

Response:

Consistent with FEI's reporting on other CPCN projects approved by the BCUC, FEI does not intend to provide adjusted cost estimates if it is able to secure price reductions, but will provide cost variance reports as part of its progress reports to the BCUC regarding the Project.

42. Reference: Exhibit B-7, CEC 1.13.2

<u>Response:</u>

Please refer to the response to BCUC IR1 3.3 for a detailed listing of activities FEI uses to manage third-party damage threats and natural hazards. These activities have been undertaken and continue to be undertaken on <u>every</u> transmission pipeline.

The activities FEI uses to manage third-party damage threats and natural hazards are appropriate mitigation of the threats of third-party damage and natural hazards for its transmission pipelines, reflecting factors such as FEI's current awareness of site-specific risks and current industry practice. FEI is nonetheless committed to continually improving and advancing its IMP, and will continue to explore practical and cost-effective activities to manage third-party damage threats and natural hazards.

42.1 In BCUC 1.3.3, FEI cites the following activities to manage third party damage threats:

- Visual inspection;
- Vegetation management;
- Signage;
- Public awareness;
- Management of Third-Party activities in the vicinity of its pipelines to enable third party activity to proceed;
- Depth of cover monitoring;
- Inline inspection and condition monitoring;
- Geotechnical and hydrotechnical hazards; and
- Seismic hazards.

Please confirm that FEI also routinely addresses security threats arising from intentional damage, and third-party unintentional damage.

<u>Response:</u>

Confirmed. FEI primarily monitors for potential security threats to its transmission pipelines through visual inspections of its system.

42.2 Please confirm, or otherwise explain, that the TIMC project would have little to no impact on threats from intentional damage, and third-party unintentional damage.

Response:

Confirmed. The ITS TIMC Project would have little to no impact on intentional damage and third-party unintentional damage threats.

43. Reference: Exhibit B-7, CEC 1.20.1

20. Reference: Exhibit B-1, pages 76 and 77

> ***4.4.2.1 Sub-System 1 between Kingsvale Control Station and Oliver Y Control Station***
>
> The first sub-system operates between the Kingsvale Control Station in Kingsvale, BC and the Oliver Y Control Station in Oliver, BC via the KIN PRI 323 and PRI OLI 323 transmission pipelines. These pipelines provide gas to approximately 2,700 existing customers in local communities surrounding the pipelines. However, the majority of capacity on the KIN PRI 323 and PRI OLI 323 pipelines is used to provide additional gas to FEI's CTS. While FEI sources most of the gas needed for the CTS from northern BC via Enbridge's transmission pipeline system, as shown in Figure 4-5, the KIN PRI 323 and PRI OLI 323 pipelines are able to deliver gas from TC Energy in Alberta to the Lower Mainland via FEI's NPS 24 Southern Crossing Pipeline and Enbridge's transmission pipeline system. Thus, the KIN PRI 323 and PRI OLI 323 pipelines provide an alternate source of supply to the CTS and are capable of providing support in the event of a supply interruption from Enbridge north of Kingsvale.
>
> As described in Section 4.2.2, Alternative 2 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 KIN PRI 323 and PRI OLI 323 operate at a maximum hoop stress level of 59 percent of SMYS. The pressure reduction required to achieve a hoop stress below 30 percent of SMYS would result in FEI being able to supply only approximately 30 percent of the gas that can be delivered to the CTS currently. As such, in the event of a supply interruption on the Enbridge transmission system north of Kingsvale, FEI would be further limited in its ability to support the CTS.

20.1 It appears that key sub-system 1 concerns relate to the ability for FEI to serve its CTS customers. What alternatives would be available for FEI to serve CTS customers?

<u>Response:</u>

FEI is typically able to deliver a maximum of 105 million standard cubic feet per day (MMSCFD) of gas to Enbridge's transmission system at Kingsvale which is used as a portion of the total supply required for the CTS and other communities between Kingsvale and Huntingdon. A permanent reduction in the operating pressures of the KIN PRI 323 and PRI OLI 323 pipelines (as proposed in Alternative 2) would result in FEI being able to provide only a fraction of the current delivery to the Lower Mainland. As such, FEI would need to source additional supply in the open market to replace the balance of the gas. This would be challenging and costly given that the Enbridge T-South pipeline system is fully contracted and can be constrained during the winter when there is high gas demand. As a result, FEI would need to pay some premium to a counterparty to obtain their capacity from the T-south pipeline system or expose FEI customers to significantly higher and more volatile supply at the Huntingdon/Sumas market.

43.1 Please explain what impact, if any, an increase in the LNG available from Tilbury would or could have on the need for the KIN PRI 323 and PRI OLIC 323 alternative.

Response:

The capacity provided by the KIN PRI 323 and PRI OLI 323 pipelines is relied upon on a daily basis and, in particular, through the winter, to provide supply to the Lower Mainland and Vancouver Island. As such, a significant increase in the LNG available from Tilbury would be required to reduce or negate the need for the delivery volumes at Kingsvale that are only possible if existing operating pressures in the KIN PRI 323 and PRI OLI 323 pipelines are maintained.

FEI estimates that it would need 11 BCF of tank capacity (almost 4 times the size of FEI's proposed Tilbury Liquefied Natural Gas Storage Expansion (TLSE) Project) and associated liquefaction and vaporization capacity to offset the gas supply benefit of maintaining the KIN PRI 323 and PRI OLI 323 pipelines at their current operating pressure. This infrastructure would be significantly more costly when compared to implementing an EMAT ILI program on the KIN PRI 323 and PRI OLI 323 pipelines.

The following illustrates the potential amounts of LNG required to offset the gas supply benefit of maintaining the KIN PRI 323 and PRI OLI 323 pipelines at their current operating pressure:

- As explained in Section 4.4.2.1 of the Application, the pressure reduction required to achieve a hoop stress below 30 percent of SMYS on the KIN PRI 323 and PRI OLI 323 pipelines would result in FEI being able to supply only approximately 30 percent of the gas that can currently be delivered to the CTS, resulting in a delivery of approximately 30 MMSCFD.
- To maintain a maximum delivery of 105 MMSCFD to the CTS, the approximately 75 MMSCFD deficit would need to be replaced through LNG.
- Currently, the gas provided by the KIN PRI 323 and PRI OLI 323 is planned for use throughout the year, with approximately 150 days in winter requiring the maximum supply of 105 MMSCFD. If only winter supply needs were considered, FEI would require approximately 11,250 MMSCF[1] per year, which is equivalent to approximately 11 BCF of LNG.
- For reference, FEI's proposed TLSE Project includes the installation of a 3 BCF LNG storage tank, 2 BCF of which will be reserved for resiliency, leaving 1 BCF that could be used as a peak-shaving resource to help make up the deficit listed above. Should the TLSE Project be approved as proposed, FEI would need an additional 10 BCF tank and associated liquefaction and vaporization capacity to offset the gas supply benefit of maintaining the KIN PRI 323 and PRI OLI 323 pipelines at their current operating pressure.

[1] (75 million standard cubic feet per day) x (150 days per year) = 11,250 million standard cubic feet of gas per year.

44. Reference: Exhibit B-7, CEC 1.22.1 and 1.2.1

22. Reference: Exhibit B-1, page 81 and page 82

Table 4-4: NPV Cost Comparison of CTS TIMC Alternatives (2020$)

	Alternative 4: EMAT ILI ($ millions)	Alternative 5: PLR ($ millions)	Alternative 6: PLE ($ millions)
Net Present Value of Total Capital and O&M Cost[75]	$307	$1,811	$1,902

Based on the order of magnitude differences in cost between the alternatives, and recognizing that the total length of the 11 CTS pipelines was approximately 254 km and the total length of the 8 ITS pipelines is approximately three times longer (752 km), FEI did not consider it a prudent use of funds to undertake another cost estimate of these alternatives for the ITS TIMC Project.[76]

Table 4-5: Relative Cost Comparison of Three Remaining Alternatives (using NPVs from CTS TIMC Project)

	Alternative 4: EMAT ILI	Alternative 5: PLR	Alternative 6: PLE
Relative Cost	1	5.9	6.2

22.1 FEI states that it would not be a prudent use of funds to undertake a cost estimate for the ITS alternatives, and instead relies on the information from the CTS Project. What is the approximate cost of undertaking a preliminary cost estimate for the ITS alternatives?

Response:

Based on its PLR and PLE cost estimates obtained during the development of the CTS TIMC Project, FEI estimates the cost of undertaking a preliminary cost estimate (i.e., Class 5) for each alternative to be between approximately $45 and $60 thousand per estimate. FEI estimates six months would be required to produce the estimates.

Response:

While the cost estimate provided for the ITS TIMC Project does not include any reduced pricing from FEI's suppliers or service providers, during the execution phase of the Project, FEI will seek to secure reduced pricing from its suppliers for materials and services to address projects on more than one transmission system over a short period of time. FEI's procurement practices are performed ethically and in accordance with prudent business practices to achieve the greatest overall value for the project(s) requirements. Further, whenever possible, FEI consolidates requirements across projects and utilizes existing agreements to achieve the greatest overall value for the project(s). FEI's procurement practices include working with vendors and manufacturers through a competitive bid process.

44.1 Please discuss any potential cost or other impacts that would arise from a six-month delay.

Response:

FEI interprets the CEC's question as asking what the impact would be to pause the ITS TIMC regulatory proceeding for six months while Class 5 estimates and NPV calculations were developed for the PLE and PLR alternatives.

Based on the Project schedule provided in Table 5-1 of the Application (page 99), a six-month delay would likely shift approval to late Q1 2024 (from Q3 2023). This delay in Project approval would have compounding effects through the Engineering Detailed Design, Permitting and Procurement phases, resulting in the start of construction of Phase 1 activities shifting from April 2025 to April 2026. In turn, this delay would result in an inability to complete the baseline EMAT ILI tool run on the Savona to Penticton 323 mainline and complete necessary repairs prior to the winter of 2026. Ultimately, a delay of this kind would negatively impact FEI's ability to execute the proposed operational strategy to manage capacity requirements in a pressure reduced scenario without the Okanagan Capacity Upgrade Project, as set out in the response to BCUC IR1 1.2.1.

44.2 Please explain whether or not a preliminary cost estimate would incorporate the potential cost benefits that could be achieved from undertaking two major projects in a short time period.

Response:

Preliminary cost estimates (i.e., Class 5) generally apply stochastic estimating methods such as gross unit costs (cost/length), factoring and other parametric and modeling techniques and, therefore, would not take into consideration potential cost benefits that could be achieved from undertaking two major projects in a short time period.

44.3 Are there benefits from staggering the transmission line specific tests for the ITS TIMC and the CTS TIMC so as to level the FEI activity?

Response:

FEI interprets the CEC's reference to "transmission line specific tests" to mean EMAT ILI runs.

While there are benefits from staggering the EMAT ILI runs between the CTS and ITS pipelines, these benefits are secondary to the need to complete baseline runs over a reasonable planning horizon – reflecting the time-dependent nature of cracking threats. In doing so, FEI has appropriately considered:

- Scheduling work earlier on those pipelines with capacity constraints;
- Generally scheduling baseline EMAT ILI runs on higher risk pipelines earlier; and
- Minimizing operational risk by allowing for sufficient time for crack repairs prior to initiating the next EMAT run(s) in the schedule.

FEI has staggered the proposed baseline EMAT ILI run years, as shown in the table below, to the extent that such staggering does not impede its ability to manage cracking threats on the ITS without undue delay. This approach will promote a more even distribution of FEI's resources.

Pipeline	Baseline Run Year (Proposed)
CTS TIMC	
HUN ROE 1066	2024
HUN NIC 762	2025
NIC PMA 610	
NIC FRA 610	
ROE TIL 914	2026
CPH NOO 508	
LIV PAT 457	
TIL BEN 323	2027
TIL FRA 508	
TIL LNG 323	
LIV COQ 323	
ITS TIMC	
SAV VER 323	2026
VER PEN 323	
PEN OLI 273	2028
OLI GRF 273	
GRF TRA 273	
YAH TRA 323	2030
KIN PRI 323	2032
PRI OLI 323	

45. Reference: Exhibit B-7, CEC 1.24.2 and 1.24.3

Line Name	Approximate Length (km)	Average Time to Complete EMAT Run (hr)	Average Time to Complete MFL-C Run (hr)
SAV VER 323	143	26	20
VER PEN 323	99	18	14
GRF TRA 273	60	11	8
OLI GRF 273	95	18	13
PEN OLI 273	30	6	4
KIN PRI 323	67	12	9
PRI OLI 323	95	18	13
YAH TRA 323	163	30	23

24.3 FEI states that when it obtains degraded data it sometimes relies on data from prior successful runs of the same technology, which implies variability in the degradation from one run to another. Could FEI repeat ILI runs where the information is extensively degraded and potentially get better data from the combination of more than one set of data? Please explain why or why not.

Response:

Repeat ILI runs, whether performed over a shorter or longer-term period, can produce variability in data degradation. While a combination of more than one set of data (from repeat ILI runs) could potentially provide better data than a single data set, a repeat ILI would not be expected to produce a significantly different result in the absence of addressing a controllable factor (e.g., addressing heavy-wall pipe to minimize the potential for speed excursions).

Variations in tool velocity, pipeline cleanliness and tool performance can all produce variability in data degradation from one ILI run to another. For example:

- Tool velocity can vary from one run to another due to gas flow conditions in the pipeline at the time of the ILI tool run. Customer gas use varies from day to day and over the duration of the ILI tool run.
- Tool velocity can vary from one run to another due to changes in piping, for example by undertaking modifications to heavy-wall pipe to minimize the potential for speed excursions.
- Pipeline cleanliness can fluctuate over time and can contribute to variability in data degradation, despite FEI taking all reasonable proactive steps.
- Vendor tool performance can vary between runs. Variability in performance exists between different vendors. Also, the same vendor may be able to take steps to reduce friction and enhance speed control from one run to another.

Ultimately, while some variability can be controlled by an operator, other aspects cannot be controlled (e.g., customer gas use during an ILI tool run).

45.1 How long does it take for FEI to become aware that the data achieved in its ILI runs is degraded?

Response:

FEI is typically informed, on a preliminary basis, that the data obtained in an ILI run is degraded within 14 days after the run, subject to some variation based on the tool being run and vendor selected.

FEI continues to provide field verification results to the vendor over the subsequent year(s) following an EMAT ILI tool run. The final report, which can be two to three years following the EMAT ILI tool run, provides FEI with a higher level of certainty regarding data degradation.

45.2 Please describe the optimal and the non-optimal customer gas use conditions for running an ILI tool, and in what ways the data would improve if these conditions were present.

Response:

Optimal gas use conditions for running an ILI tool would entail having adequate and consistent customer load to maintain flow rates and associated tool velocities within the optimal range, throughout the entire length of the pipeline being inspected. This is not representative of actual customer gas use conditions on FEI's transmission pipelines.

Non-optimal gas use conditions for running an ILI tool, which are typical on FEI's system and contribute to inconsistent flow rates and can lead to ILI tool velocities outside of the optimal range, are caused by:

- Customer gas use fluctuating on the day-of-run due to the outside temperature and varied usage during the day.
- Customer gas use fluctuating along the length of the pipeline being inspected due to gas being diverted to customers through gate stations situated along the length of the transmission pipeline.

Improved ILI data can generally be obtained under optimal gas use conditions as these conditions reduce the likelihood of speed excursions caused by changing gas flows. Consistent tool speed during an ILI run also improves the ability of the vendor to achieve or exceed their tool (detection and sizing) performance specifications.

45.3 Please confirm that FEI has extensive data on customer gas use patterns, including time of day and seasonality.

Response:

While FEI has data on customer gas use patterns, including time of day and seasonality, as explained in the response to CEC IR2 45.2, gas use conditions on the ITS are non-optimal, thus contributing to inconsistent flow rates which increase the risk of ILI tool velocities outside of the optimal range.

45.4 Is FEI able to schedule its ILI tool runs at times in which it anticipates optimal gas use from customers? Please explain why or why not.

Response:

No, FEI is not able to schedule its ILI tool runs at times in which it anticipates optimal gas use from customers. As explained in the response to CEC IR2 45.2, non-optimal gas use conditions are typical of FEI's system.

45.4.1 If FEI is able to schedule its ILI runs during periods of optimal customer gas use times, would this change be sufficient to improve the data quality and allow reductions in the replacements of heavy walls that cause speed excursions? Please explain why or why not.

Response:

As explained in the response to CEC IR2 45.4, non-optimal gas use conditions are typical of FEI's system; therefore, FEI is unable to schedule ILI tool runs during periods of optimal customer gas use. As such, this change is not available to FEI and would not allow reductions in the proposed replacements.

If, hypothetically, FEI were able to schedule its ILI runs during periods of optimal customer gas use times, ILI data quality would improve as it would reduce the occurrence and impact of speed excursions on data quality.

46. Reference: Exhibit B-7, CEC 1.25.1

25. Reference: Exhibit B-1, page 95

5.4.4 Pressure Regulation Is Required to Support EMAT ILI Activities

As described in detail in Section 3.5.2, FEI's statutory and regulatory obligations align with FEI's efforts to take additional measures to mitigate the risk of failure on the 8 ITS pipelines due to cracking threats. As the extent of the threats is unknown until after the successful EMAT ILI run and initial data analysis, FEI must consider and be ready to implement additional operational changes to safeguard the system through pressure reduction.

25.1 Does FEI expect to provide information to the Commission regarding the extent of SCC threats following its initial ILI runs? Please explain and, if yes, explain when this could be expected to occur.

Response:

FEI's integrity management activities are under the regulatory review, oversight, and authority of the BCUC, BC OGC, and the NEB. Visibility of FEI's activities to the BCUC, including the extent of SCC threats and mitigation and maintenance work to address SCC threats, will occur through FEI's future BCUC regulatory proceedings, including future Revenue Requirements and Annual Review proceedings.

46.1 Does FEI expect to specifically report on its SCC threat findings in the RRA or Annual Review proceedings, or does FEI expect to provide general information regarding the projects only?

Response:

In addition to the reporting FEI already provides in RRA or Annual Review proceedings regarding integrity dig expenditures, FEI expects that it would report on its SCC threat findings to the extent it needs to justify expenditures for the work to address those findings.

46.2 Would FEI expect that the results of initial runs on the CTS pipeline could influence the understanding of the risks on the ITS pipeline? Please explain why or why not.

Response:

As described in the Application, cracking is a highly localized and often unpredictable phenomenon. Therefore, FEI would not have sufficient confidence in the applicability of EMAT ILI results on the CTS pipelines to the ITS pipelines to adjust its estimates and understanding of the risks on ITS pipelines. Further, the QRA incorporates historical industry failure rates from a far broader sample size, which is a more accepted method for estimating cracking risk on pipelines in the absence of EMAT ILI data.

47. Reference: Exhibit B-7, CEC 1.32.3

> 32.3 Why is seven years likely the appropriate length of time for repetition to monitor the growth of crack line threats to the pipeline?
>
> **Response:**
>
> Canadian pipeline standards are generally not prescriptive in nature, thereby affording operators the flexibility to determine appropriate re-inspection intervals for pipeline assets and inspection technologies, including EMAT ILI. A re-inspection is typically undertaken to assess for any new cracks and the potential growth of previously identified cracks, but can also serve other purposes, such as allowing an operator to obtain data from a more modern tool.
>
> Although the actual length of time interval for monitoring cracking threats will be line-specific, FEI has identified seven years as an approximate re-inspection timeframe based on its prior ILI experience and understanding of industry practice.
>
> In the table below, FEI provides examples from publicly available sources quantifying a re-inspection interval for ILI generally (and not necessarily specific to cracking risk):

Source	Excerpt	Relevance
CSA SPE-225.5:22, Metal Loss Inline Inspection Tool Validation Guidance Document, 1st Edition, January 2022[8]	Section 6.2.2, page 34, "Furthermore, a lengthy interval (e.g. more than 5 years) between ILI inspections or the use of very different technologies can make matching difficult if not impossible."	This indicates a consensus among CEPA members (who developed this document) that "more than 5 years" is a "lengthy interval" for a re-inspection with an ILI tool and for matching defect and/or imperfection information between ILI inspections.

Source	Excerpt	Relevance
Transportation Safety Board of Canada, Pipeline Transportation Safety Investigation Report P18H0088, Pipeline rupture and fire, Westcoast Energy Inc., Prince George, British Columbia, 09 October 2018[9]	4.1 Safety action taken From 4.1.2 Westcoast Energy Inc. "The maximum re-inspection interval for EMAT in-line inspections for all L2 pipeline segments was set to 6 years. Further, Westcoast has implemented a more conservative approach in responding to pipeline inspection data that may identify areas requiring closer monitoring or earlier maintenance work."	FEI's re-inspection interval range is consistent with this quantification of a re-inspection interval from Westcoast Energy Inc.
US Code of Federal Regulations Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards[10]	§192.937 "What is a continual process of evaluation and assessment to maintain a pipeline's integrity? […] An operator must reassess a covered segment on which a baseline assessment is conducted […] by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment." §192.939 "What are the required reassessment intervals? […] The maximum reassessment interval by an allowable reassessment method is seven years."	Part 192 contains federally regulated requirements for US gas transmission pipelines. FEI's assessment of industry practice in Canada, while not similarly prescribed in a Canadian standard or regulation, does align with this prescriptive US pipeline regulation. This provides an indication that FEI's range of re-inspection frequency is common. FEI notes that there are provisions in the US standard that allow for an extension of the maximum re-inspection interval up to 10 years for transmission pipelines inspected with ILI tools, although this requires the performance of supplemental inspections.

47.1 FEI's evidence appears to be that 'more than five years' is considered to be a lengthy interval for re-inspection and can make matching difficult if not impossible; and that the maximum reassessment interval is seven years. Please explain why

FEI did not use a lower interval period, such as every five or six years in its analysis.

Response:

In preparing its response to the question above, FEI identified that its responses to CEC IR1 32.1 and BCUC IR1 13.2 incorrectly indicated that FEI is forecasting that EMAT ILI will be run on a schedule of once every seven years.

FEI has not yet selected a re-assessment interval, but expects that EMAT tools will be run on a schedule of <u>at least</u> every seven years. As FEI stated in Table 5-7 on page 114 of the Application:

> It is estimated that these tools will need to be run <u>at least</u> every seven years to monitor the growth of crack-like threats to the pipeline and to provide information on where FEI needs to respond to and repair any crack-like threats. The actual run frequency for each pipeline will be determined after the initial baseline run, once the condition of the pipeline (with regards to the crack-like features) is better understood. [Emphasis added]

While FEI indicated in the response quoted in the preamble above that seven years is an approximate re-inspection timeframe, FEI did not utilize a seven-year re-inspection cycle for any analysis in its Application. In the response to BCUC IR1 13.2, FEI made the simplifying assumption of a seven-year re-inspection timeframe only for the purpose of estimating the costs requested in that IR.

Concurrent with these IR responses, FEI will file errata to its responses to CEC IR1 32.1 and BCUC IR1 13.2.

48. Reference: Exhibit B-7, CEC 1.32.4

32.4 What would be the most frequent cycle that pipeline runs could be usefully conducted?

Response:

The use of a re-run can be diminished if an insufficient length of time has passed for new cracks or crack growth to form, and therefore, for tool-reported information to be differentiated from tool measurement error. Although the typical industry re-inspection interval is between five to seven years for all ILI tool re-runs, FEI is informally aware of an EMAT ILI re-inspection interval as short as two years.

48.1 Would FEI consider 5 or 6 years, or another period, to represent the average re-inspection period? Please explain.

Response:

FEI considers approximately seven years to represent the average ILI re-inspection period for natural gas operators in North America based on FEI's knowledge of the practices of its peer Canadian operators and the fact that the most commonly adopted re-inspection interval adopted by operators in the US is seven years (primarily due to regulatory requirements set out in 49 CFR Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards).

48.2 Did FEI receive any formal recommendations as to preferred re-inspection periods? Please explain.

48.2.1 If yes, please provide the recommendation and the source of the recommendation.

48.2.2 Please provide any data on the known risk probabilities related to the interval time between inspection runs and if this is not quantified, please explain why.

Response:

No, FEI has not received any formal recommendations regarding preferred re-inspection periods.

FEI does not currently utilize, and does not have data of quantified risk probabilities related to, the interval time between inspection runs. FEI's reinspection intervals are line-specific, and consider factors that are both quantifiable and qualitative. FEI understands this approach to be in alignment with current industry standard practice.

Factors considered by FEI in its re-inspection interval selection currently include:

- Potential consequences of failure;
- Type and size of anomalies detected in previous inspection and the number of digs projected based on the previous inspection log;
- The confidence in quality of ILI data from previous inspection(s);
- Assessment of potential growth of time-dependent anomalies;
- Ability/need to do run to run comparisons using the same tool;
- Opportunity to adopt a more modern tool;
- Pipeline availability for in-line inspection due to operational constraints (bypasses, flow/load windows);
- Co-ordination of runs of pipelines of the same diameter to reduce tool mobilization cost;
- Opportunities to run multiple tool technologies in a given line in the same year so that pre-ILI pipeline cleaning can be leveraged for as many ILI runs as possible;
- Presence of degraded ILI data quality due to speed excursion and/or debris;
- Industry standard/leading practices; and
- Engineering judgment, incorporating appropriate engineering conservatism.

As FEI's risk assessment capabilities are further developed and enhanced, it is possible that risk probabilities related to the interval time between inspection runs may be quantifiable, leveraging estimated growth of time-dependent ILI-reported anomalies, and that this information may inform re-inspection interval selection.

49. Reference: Exhibit B-7, CEC 1.32.5

32.5 What would be the approximate cost of a future run of the EMAT ILI tools?

Response:

As noted in the response to BCUC IR1 13.2, a single EMAT ILI tool run can range from $1.5 to $2.5 million (inclusive of both FEI's costs and contractor costs).

49.1 Are there other direct or indirect costs that would occur with more frequent ILI runs?

Response:

Yes, FEI would incur increased costs with more frequent ILI runs. For example, increased direct costs to FEI (whether by internal or contractor resources) could be incurred in the following areas:

- Increased ILI tool vendor costs, as there would be a greater number of tool runs over a given period of time;
- Increased internal and contractor costs associated with cleaning pipelines and running tools;
- Increased costs associated with pre-arranged, FEI-funded, increases or decreases to the gas use of an industrial customer in order to support ILI tool velocity within the range required for data collection; and/or
- Increased resources to analyze and respond to increased quantities of ILI data.

An example of an indirect cost arising from increased operational and engineering resources would include training and development costs for those resources.

49.2 What are the potential benefits that would arise from more frequent ILI runs? Please quantify to the extent possible.

Response:

The potential benefits that would arise from more frequent ILI runs include:

- Potential for a reduced number of integrity digs, as corrosion and crack growth rates would be applied over shorter timeframes prior to verification through a re-inspection;
- Potential to adopt improved ILI tools earlier, if tools have evolved since the last inspection; and

- Earlier detection of features growing at unusually fast rates, to the extent that such features exist and are within the detection and sizing threshold(s) of the tool(s).

Please also refer to the response to CEC IR1 32.4 which explains that it can also be difficult to differentiate crack growth from toll measurement errors if an insufficient length of time has passed for new cracks or crack growth to form. This is a potential downside that could arise from more frequent ILI runs.

50. Reference: Exhibit B-7, CEC 1.33.1 and 1.33.2 and Exhibit B-4, BCUC 1.17.1

With regard to the potential impact of hydrogen blending on the used and useful life of FEI's pipeline, this was addressed in the CTS TIMC Project CPCN proceeding and is also applicable to the ITS TIMC Project. The CTS and ITS pipelines are capable of safely transporting a blend of hydrogen and the pipelines will continue to be used and useful even if hydrogen blends are introduced into the pipelines.[11] Furthermore, the EMAT ILI tools will continue to be needed and used on the CTS and ITS pipelines for integrity purposes regardless of whether the pipeline is transporting a blend of hydrogen or not. As such, FEI has no reason to believe the ITS pipeline or the assets associated with the ITS TIMC Project will become stranded over the 65-year post-Project analysis period.

Given the reasons above, the use of a 65-year average service life is reasonable and appropriate for the purposes of evaluating the financial impact due to the ITS TIMC Project. This was also accepted by the BCUC in its decision on the CTS TIMC Project:[12]

> While the Panel has raised concerns about the potential impact of future hydrogen blending on the used and useful life of FEI's pipelines as already discussed earlier, the Panel also finds FEI's use of a 70-year analysis period based on a 65-year post-Project analysis period to be reasonable as it reflects the average service life of transmission mains pooled assets in FEI's 2017 Depreciation Study.

Response:

The statement referenced in the preamble is referring to the potential blend of hydrogen in FEI's system and that FEI is unable to predict the amount of hydrogen in the system after 2040 or 2050; the statement is not suggesting that FEI's system will not be used and useful after 2040 or 2050. As discussed in the response to CEC IR1 33.1 and in the CTS TIMC Project CPCN proceeding, FEI's pipelines are expected to remain used and useful regardless of the amount of hydrogen that is blended into the system. As such, the use of a 70-year analysis period (65-year post-Project analysis period plus 5 years for construction) is reasonable and appropriate.

50.1 Is there any reason to consider that the addition of hydrogen into the system could result in additional damage to pipelines, or result in an increased need for ILI tools? Please explain.

Response:

The introduction of hydrogen into the ITS could result in an increased need for ILI tools to manage integrity, as existing research indicates hydrogen can potentially impact steel toughness and pipeline fatigue depending on hydrogen blend concentration in natural gas. In particular, as explained in the response to BCUC Panel IR1 1.1 in the CTS TIMC proceeding (Exhibit B-19):

> Hydrogen has different chemical properties compared to methane. The most significant concern in the context of steel pipelines is variously known as "hydrogen embrittlement" or "hydrogen induced cracking". Hydrogen gas is made up of hydrogen molecules which can dissociate into hydrogen atoms on the inside

surface of steel pipe and, because hydrogen is the smallest atom, it has some propensity to adsorb into the steel lattice comprising the pipe body and welds. This can degrade the mechanical properties of the steel, and, in simple terms, can cause it to become more brittle and result in the formation or growth of cracks.

FEI is undertaking additional investigation to understand the extent of this risk and to what extent it can be mitigated prior to any hydrogen injection into FEI's transmission system. However, it is clear that, in addition to allowing FEI to identify and address any cracking threats on the ITS pipelines, EMAT ILI will help it evaluate the safe operation of the ITS pipeline under various potential hydrogen blending scenarios.

50.2 Is there any evidence to suggest that hydrogen in the system would cause increased probability of risk to the pipelines and thereby increase the need for EMAT ILI tools? Please explain.

Response:

Please refer to the response to CEC IR2 50.1.

51. Reference: Exhibit B-7, CEC 1.37.1

> **Response:**
>
> The *Environmental Management Act* (EMA) (Division 3) and *Contaminated Sites Regulation* (CSR) (Part 7), establish the framework for determining who is responsible for remediation of contaminated sites. Where FEI is not determined to be a "responsible person" under EMA and the CSR, it would not be responsible for remediating the entirety of a contaminated site.
>
> If contamination is encountered on FEI-owned property, and FEI is determined to be a responsible person under the EMA and the CSR, then FEI could be required to remediate areas of the FEI property to be disturbed during construction activities. FEI would not be required to remediate the entire site at the time of Project construction; however, if the property is considered "high-risk" then the remediation of high-risk conditions could be required.
>
> If contamination is encountered on FEI-owned property and it is determined that a third-party is responsible for the contamination (i.e., contamination migrating from a neighbouring property),
>
> FEI could be required to remediate areas of the FEI property to be disturbed during construction activities. FEI could, through legal action and following the completion of remediation, attempt to recuperate the costs of remediation from the responsible person(s).

51.1 Please confirm that FEI would undertake its best efforts, including legal action, to recover any costs of remediation, where a third party was considered to be responsible.

Response:

If FEI is required to remediate a contaminated site where a third party was considered to be responsible, FEI will take the action that is in the best interest of customers considering the unique circumstances of each site, including taking reasonable actions to recover the costs of remediation from the third party. Before pursuing recovery of costs through legal action, FEI would consider factors such as the cost of pursuing a legal action, the probability of success of any legal action, and the ability of the third party to pay if the legal action were successful.