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February 16, 2023

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

Attention: Sara Hardgrave, Acting Commission Secretary

Dear Sara Hardgrave:

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 British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On September 20, 2022, FEI filed the Application referenced above. In accordance with BCUC Order G-18-23 amending the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

FEI requests that a portion of the responses to BCUC IR1 3.2 and 6.2.1, which are redacted in the public version, be filed on a confidential basis pursuant to section 19 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-178-22. The confidential information identifies vulnerable points on FEI's gas transmission system and areas of risk to FEI's assets. Disclosure of the detailed information could impede FEI's ability to work safely and to reliably operate its gas system assets and could risk the safety of both its workers and the public. A confidential version of the responses has been provided to the BCUC and Interveners who have signed a Confidentiality Declaration and Undertaking.

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): Registered Parties

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A. PROJECT NEED AND JUSTIFICATION

1.0 Reference: PROJECT NEED AND JUSTIFICATION

FortisBC Energy Inc. Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) CPCN Proceeding, Exhibit B-5, BCUC IR 4.4; BCUC Order G-48-22, Appendix A, p. 2

Okanagan Capacity Upgrade Project

In response to British Columbia Utilities Commission (BCUC) IR 4.4 in FortisBC Energy Inc.'s (FEI) CTS TIMC CPCN Proceeding, FEI stated:

> No high risk pipelines on the ITS have been deferred by prioritizing work on the CTS, but rather, as explained further below, some risks cannot be addressed until the capacity improvements outside the scope [of] the ITS TIMC Project are completed…
>
> In order to address the cracking threats on the highest risk ITS pipeline, the Okanagan Capacity Upgrade (OCU) Project, for which a CPCN Application was filed with the BCUC on November 16, 2020, must be in service to ensure that FEI is able to meet customer demand in the event that the SCC-susceptible pipeline in the ITS is required to operate at a 20 percent pressure reduction for an extended period. [Emphasis added]

The BCUC adjourned the OCU Project CPCN proceeding by Order G-48-22, dated February 23, 2022. On page 2 of Appendix A of this Order, the BCUC stated:

> In recent months, there have been numerous delays and extension requests to the regulatory process to facilitate further engagement between FEI and PIB

[Penticton Indian Band]. Further, there is a lack of clarity with respect to the precise timing and content of FEI's proposed evidentiary update, which may depend on the outcome of further engagement with PIB.

1.1 Please provide an update regarding the current status of FEI's OCU Project.

1.1.1 Please provide an update regarding the status of FEI's proposed evidentiary update noted above.

Response:

FEI and the Penticton Indian Band (PIB) continue to engage on the proposed OCU Project in an effort to seek the PIB's consent for the OCU Project. Upon conclusion of those discussions, FEI will provide an update to the BCUC on the outcome. FEI anticipates communicating with the BCUC on the matter before the end of Q1 2023.

1.2 Please explain why FEI is proceeding with the scope of the ITS TIMC Project prior to completing capacity improvements on the ITS.

Response:

FEI is proceeding with the scope of the ITS TIMC Project prior to completing the capacity improvements proposed to be undertaken through the OCU Project for the following reasons:

- FEI has identified pipelines on the ITS that are susceptible to cracking, including through the QRA reports prepared by JANA, the findings of SCC on FEI's pipelines, and the knowledge and experience of other pipeline operators;
- Cracking is a time-dependent threat, meaning there is an increasing potential to impact the pipeline over time, and FEI needs to ascertain integrity information on its pipelines in a timely manner to mitigate the potential for failures;
- FEI needs to align with evolving industry best practices that include utilizing EMAT ILI tools with new and improved capabilities and functionalities to assess, manage and mitigate cracking; and
- FEI has regulatory obligations to mitigate cracking threats to its transmission pipelines.

FEI prioritized its CTS TIMC Project due to the higher safety risk of the CTS pipelines as compared to the ITS pipelines. By submitting the ITS TIMC Project after the CTS TIMC Project, the proposed ITS TIMC Project timeline also aligned with the original in-service date of the OCU Project (Q3 2023). However, due to unforeseen delays with the OCU Project, FEI developed an operational strategy to manage capacity requirements in a pressure reduced scenario without the

OCU Project pipeline following the baseline EMAT ILI run. This strategy allows FEI to mitigate cracking threats on the ITS without delay, reflecting the reasons driving the need for the ITS TIMC Project outlined above.

Please refer to the response to BCUC IR1 1.2.1 for further information on the operational strategy FEI developed in response to the delay of the OCU Project.

1.2.1 Please explain how, without the OCU Project in service, FEI will meet customer demand in the event that an ITS pipeline will be required to operate at a 20 percent pressure reduction for an extended period.

Response:

The OCU Project or another equivalent capacity improvement is needed to address the need for additional capacity to meet forecast increased demand on the ITS, the majority of which is concentrated in the Okanagan region (served by the Savona to Penticton 323 mainline). In the context of the ITS TIMC Project, the OCU Project, or another equivalent capacity improvement, is needed to support operation of the Savona to Penticton 323 mainline at a 20 percent pressure reduction. In short, FEI cannot meet peak demand requirements under a pressure reduced scenario on the entire Savona to Penticton 323 mainline without taking mitigating action.

Therefore, in order to maintain capacity in the event of a pressure reduction being required on the Savona to Penticton 323 mainline following the baseline EMAT ILI tool run, FEI must undertake the operational strategy outlined below. FEI will complete the baseline EMAT ILI run on the Savona to Penticton 323 mainline in 2026 or earlier, before increasing demand renders this strategy not feasible.

- If significant cracking[1] is identified by EMAT ILI, FEI will conduct integrity digs and perform crack repairs on the Savona to Penticton 323 mainline in two stages, as it is possible that there will be too many repairs for FEI to complete prior to the winter.
    - Prior to winter 2026, FEI will prioritize integrity digs and performing crack repairs on 100 km of the Savona to Penticton 323 mainline nearest to the supply points into the mainline at Savona and Penticton, as listed in Table 1 and shown in Figure 1 below. FEI will prioritize these segments as the ability to operate these segments of the mainline without a pressure reduction are key to maintaining capacity through the winter in the Okanagan without additional capacity such as would be provided by the OCU Project. This work must take place prior to winter 2026 to

[1] Significant cracking is referred to in the Application as cracking that is “most likely to fail”. Significant cracking warrants incremental mitigation.

ensure these segments of the mainline can be safely operated without a pressure reduction through winter of the baseline run year.

Table 1: Prioritized Repairs on Savona to Penticton 323 Mainline

Pipeline	Total Length (km)	Length of Pipeline with Prioritized Repairs (km)	% of Pipeline with Prioritized Repairs
SAV VER 323	143	64	45%
VER PEN 323	99	36	36%
Combined Total	**242**	**100**	**41%**

- Through the winter of 2026/2027 and until the necessary integrity digs and repairs are complete, FEI will operate the remaining approximately 59 percent of the Savona to Penticton 323 mainline at a reduced pressure. In order to maintain a pressure reduction on only these portions of the mainline, FEI will:
  - Install a temporary PRS at the SN-4 Valve Assembly to apply a pressure reduction east of the Valve Assembly. The details of the PRS are discussed in Section 5.4.4.1 of the Application.
  - Utilize the existing SN 9-3 Control Station to apply a pressure reduction north of the Control Station.
- FEI will perform integrity digs and crack repairs on the remaining portion of the Savona to Penticton 323 mainline in the following year, 2027.

- FEI will negotiate with specific firm large-volume customers to have the ability to make temporary demand reductions if required. The demand reductions required are further discussed in the response to BCUC IR1 10.1.

Figure 1 below illustrates the operational strategy needed to meet capacity in a reduced pressure scenario without the OCU Project.

Figure 1: Map of Savona to Penticton 323 Mainline Operational Strategy

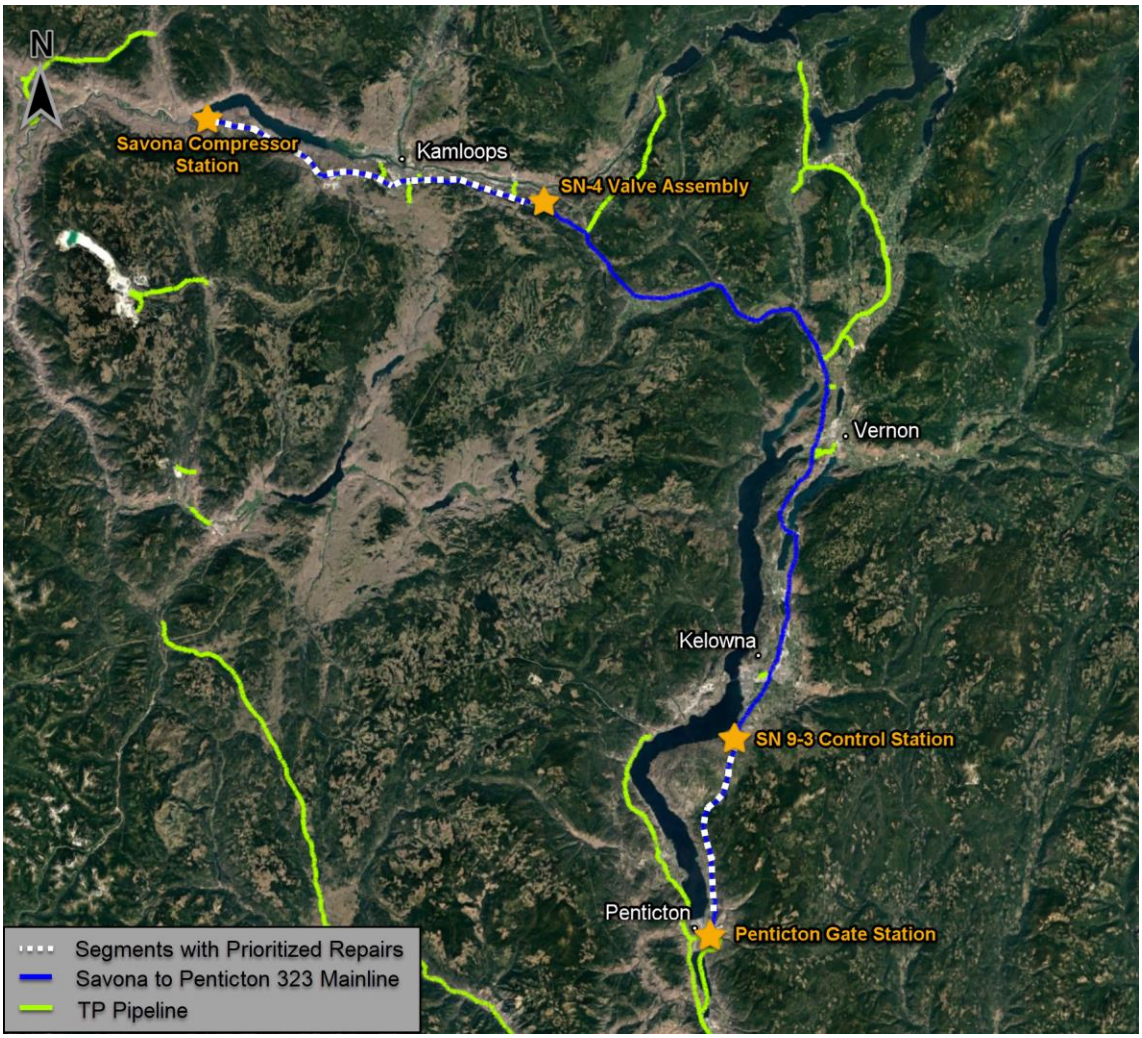


Table 2 below shows the schedule for the operational strategy. FEI emphasizes that the operational strategy is only feasible if the baseline EMAT ILI run is completed in 2026 or earlier because FEI expects increasing demand, resulting from anticipated growth on the ITS, to become increasingly challenging to manage through an operational response.

Table 2: Schedule for Baseline EMAT ILI on the Savona to Penticton 323 Mainline (2023 to 2027)

ITS TIMC	2023				2024				2025				2026				2027			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Savona to Penticton 323	BCUC reviews and approves ITS TIMC CPCN Application				Detailed Design / Fabrication / Construction (Phase 1)								MFL-A Run[2]	EMAT Run	Reduce pressure & perform priority pipeline repairs (100 km)		Restore pressure (100 km)	Perform remainder of pipeline repairs (142 km)			Restore pressure (242 km)

FEI notes that, in the absence of the OCU Project or another equivalent capacity improvement, the following short-term mitigation measures described in Section 4.2 of the OCU Project CPCN Application[3] are required for normal operations, and assumed to be already in place when the operational strategy is implemented:

- Improving peak day pressure at Savona into the north and central Okanagan on the NPS 12 Savona to Penticton mainline;
- Shifting load from the critical stations at Kelowna #1 Gate and Polson Gate to other areas with capacity to temporarily accept the load shift;
- Modifying stations at critical locations to enable them to operate reliably at pressures below FEI's normal design standard minimums; and/or,
- Monitoring and managing existing or new customer loads that may be moderated or shifted out of the peak hours with low or no adverse customer impact.

FEI anticipates that the OCU Project, or another equivalent capacity improvement, will be in-service prior to baseline inspections of the Penticton to Trail 273, East Kootenay Link 323 and Kingsvale to Oliver 323 mainlines planned for 2028 through 2032, and future runs on the Savona to Penticton 323 mainline. Since these baseline runs are proposed to be completed in the 5-to-10-year planning horizon, FEI will re-evaluate capacity requirements closer to each baseline run and plan for capacity mitigation accordingly, including if the OCU Project or another equivalent capacity improvement is not yet in-service.

[2] The magnetic flux leakage – axial (MFL-A) tool run must occur prior to the EMAT ILI run. Data from the MFL-A tool informs the interpretation of EMAT ILI run results.

[3] https://docs.bcuc.com/Documents/Proceedings/2021/DOC_60485_B-1-2-FEI-OCU-CPCN-Updated-Application.pdf

2.0 Reference: PROJECT NEED AND JUSTIFICATION

FEI CTS TIMC CPCN Decision, Order C-3-22, p. 60

BCOGC Audit

On page 60 of BCUC Order C-3-22, the BCUC stated:

> FEI states that, in February 2021, it was selected for an audit of its Integrity Management Programs (IMPs) by the BCOGC's [BC Oil and Gas Commission] Compliance Assurance Process. Discussions between FEI and the BCOGC regarding this audit continued into October 2021.
>
> The Panel requests that FEI include an update regarding BCOGC activities as they relate to oversight of FEI's IMPs, including any outcomes from the IMP audit such as corrective actions plans or directives. The Panel anticipates that this information will support the BCUC's understanding of the BCOGC's expectations as they relate to FEI's ongoing pipeline integrity management and will clarify how FEI, through its various TIMC projects, is addressing any integrity management deficiencies identified by the BCOGC.

2.1 Please provide an update regarding the BCOGC's audit of FEI's IMPs.

Response:

The BCOGC conducts regular audits of FEI's integrity management programs. In February 2021, FEI was notified of its selection for audit by the BCOGC's Compliance Assurance Process for its Integrity Management Programs, including for its pipelines and facilities.

Compliance Assurance final reports from the BCOGC dated December 15, 2021 included the following:

- With respect to the "Pipelines Integrity Management Program" review, the BCOGC remarked:

> FEI's IMPP[4] and DPP[5] audit determined that all expectations and requirements outlined in the Commission's IMP protocol for pipelines were met and no adverse findings were identified. The Commission expects FEI to remain committed and continue with improvement and advancement of their IMP.

[4] IMPP is used by the BCOGC to indicate the Pipelines Integrity Management Program, or Integrity Management Program – Pipelines.

[5] DPP is used by the BCOGC to indicate the Damage Prevention Program, which for FEI is a collection of sub-activities within its Integrity Management Program – Pipeline and is typically referred to as third party damage mitigation activities.

- With respect to the "Facilities Integrity Management Program, LNG and Compression" review, the BCOGC identified five corrective actions. These are listed below, with their current status:

Item #	Corrective Action Plan (CAP) Description	Status
1	Internal Audit Implementation - Compression	Closed (Complete)
2	Internal Audit Implementation – LNG	Closed (Complete)
3	Risk Registry – LNG	In-progress (On-Schedule)
4	Key Performance Indicators (KPI) Effectiveness – LNG	In-progress (On-Schedule)
5	Key Performance Indicators (KPI) Effectiveness – Compression	In-progress (On-Schedule)

2.1.1 Please provide a copy of any audit report provided by the BCOGC following completion of its audit, if available.

Response:

Please refer to Attachment 2.1.1 for the Compliance Assurance Reports for FEI's Pipelines Integrity Management Program and Facilities Integrity Management Program.

2.2 Please discuss how the proposed ITS TIMC Project addresses any integrity management deficiencies identified by the BCOGC through its auditing processes, or otherwise.

Response:

The ITS TIMC Project was not developed to address any integrity management deficiencies identified by the BCOGC. As described in the response to BCUC IR1 2.1, the BCOGC's most recent audit of FEI's integrity management programs did not identify any deficiencies; however, the BCOGC did state that it "expects FEI to remain committed and continue with improvement and advancement of their IMP." Consistent with the BCOGC's expectations, the ITS TIMC Project demonstrates FEI's commitment to continually improving and advancing its IMP. Also, as noted on page 48 of the Application, the BCOGC has provided written support for FEI's TIMC projects, recognizing that they are in alignment with FEI's regulatory and legal responsibilities as a BCOGC permit holder. The letter from the BCOGC to FEI, dated November 16, 2020, is attached as Appendix C to the Application.

3.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.4.1, p. 41; Section 3.4.4.2, pp. 41–43

Prioritizing the Need for ITS TIMC Project

On page 41 of the Application, FEI states:

> The purpose of a system-level QRA is to assess the overall threats to the pipeline system at a level that enables identification of general system risk and the threats driving that risk, to identify where additional integrity management activities may be warranted. Where significant risk and/or significant consequence is identified, mitigation approaches can be identified and evaluated to reduce the level of risk or to monitor for conditions that can result in those significant consequences, such as ruptures. By design, a system-level QRA uses available information to derive the best possible forecast of system risk and consequence, typically employing models based on historical industry failure rates or higher-level models.

On page 43 of the Application, FEI states:

> At the system level, the QRA estimates that the CTS has the highest risk followed by the ITS and then the VITS. As detailed in FEI's CPCN Application for the CTS TIMC Project, the QRA identified that cracking was the top driver of risk for the CTS pipelines. With respect to the ITS, JANA's model estimates that cracking threats are the second highest threat for seven of the ITS pipelines identified as susceptible to cracking threats and third highest threat for the other two susceptible ITS pipelines.

Further on page 43, FEI states: "threats that were more highly ranked than cracking on the ITS pipelines include: (1) third-party damage; and (2) natural hazards."

3.1 Please describe the methodology and assumptions FEI used to evaluate the threat of third-party damage to its pipeline system.

Response:

Section 3.3.2 of Appendix B-2 to the Application describes the basis for the model for Excavation Damage and Previous Damage, which together comprise the model to evaluate the threat of third-party damage.

The occurrence of a third-party damage event requires there to be activity above the pipeline and for preventive measures, such as BC 1 Call awareness and pipeline signage, to be ineffective. Within the model, damage potential depends on factors such as population density, land use and depth of cover.

In addition, the failure probability and failure mode (e.g., leak or rupture) in the model depend on factors such as pipeline physical properties (e.g., wall thickness, material properties), pipeline

operating properties (e.g., operating stress or %SMYS), and excavator properties (e.g., mass of excavation equipment).

FEI used historical failure rates to inform estimates of the potential for third-party damage on pipelines.

3.1.1 Please explain why the threat of third-party damage is more highly ranked for the ITS than for the CTS.

Response:

As described in Section 3.0 of the baseline system-level QRA, filed as Confidential Appendix B-2 to the Application, threat rankings represent a summarized view of the risk calculations for 23 different threats. There are numerous factors in each of JANA's calculations contributing to differences in the relative ranking of risks on a threat-by-threat basis between specific pipelines and between the various transmission systems (i.e., the CTS, ITS and VITS).

The following factors are relevant to why the threat of third-party damage is more highly ranked, on a relative basis, for the ITS than for the CTS:

- According to the SCC model, larger diameter pipelines are more susceptible to cracking. As ITS pipelines are generally smaller diameter than CTS pipelines, cracking generally has a lower estimated relative risk rank for the ITS pipelines than for the CTS pipelines. This contributes to cracking generally being ranked lower than third-party damage for ITS pipelines;
- According to the SCC model, failures due to cracking are more likely to result in rupture than third-party damage failures (resulting in increased safety risk for cracking versus third-party damage failures). As ITS pipelines tend to be located in a mix of densely populated and unpopulated areas (versus the CTS pipelines which are located in more densely populated areas), the assessed potential consequences of cracking-caused ruptures in the ITS will have a lesser estimated impact on the relative safety ranking of cracking for the ITS than they will for the CTS. Moreover, the likelihood of rupture failure and potential impact area of ignited rupture increases with pipeline diameter. Since ITS pipelines are generally smaller diameter than CTS pipelines, the estimated likelihood of rupture failure and potential impact area are typically lower for the ITS pipelines than for the CTS pipelines; and
- The initial as-constructed depth of cover of pipelines in the ITS pipeline system is generally less than that of the CTS due primarily to different historical installation practices and terrain. As the depth of cover is a contributing factor in estimates of the susceptibility of a

pipeline to third-party damage, this contributes to third-party damage typically being ranked higher than cracking threats for ITS pipelines.

While these considerations contribute to SCC typically being ranked lower than third-party damage for the ITS pipelines relative to CTS pipelines, cracking remains a credible threat which needs to be mitigated using EMAT ILI technology as proposed in the Application.

3.2 Please quantify the risk associated with: (1) third party damage; (2) natural hazards; and (3) cracking for each pipeline in the ITS TIMC Project.

Response:

A portion of this response is redacted pursuant to Section 19 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-178-22. The redaction has been made as it identifies vulnerable points on the Company's gas transmission system and areas of risk to FEI's assets. Disclosure of the detailed information could impede FEI's ability to work safely and to reliably operate its gas system assets and could risk the safety of both its workers and the public. A confidential version of this response is being filed with the BCUC and Interveners who have signed a Confidentiality Declaration and Undertaking.

The quantified risk associated with: (1) third-party damage; (2) natural hazards; and (3) cracking for each pipeline in the ITS TIMC Project is included within Appendix A4 of the JANA report filed as Confidential Appendix B-2 to the Application and is summarized in the table below.

3.3 Considering that the threat of third-party damage and natural hazards are top drivers of risk for the ITS, please discuss any risk mitigation actions that FEI has taken or could take to reduce the likelihood of a pipeline rupture from those threats.

3.3.1 Please elaborate on the relative cost and safety benefits of potential mitigation measures to reduce the risk of third-party damage or natural hazards for the ITS pipelines as compared to the proposed ITS TIMC Project.

Response:

Through its integrity management program framework, FEI develops and implements practical and cost-effective measures to mitigate the potential for rupture of its transmission pipelines, including those that could result from third-party damage and natural hazards. There can be many drivers for mitigation selection, including:

- Compliance with standards and regulations;
- Alignment to industry standard practice(s);
- Provision of adequate and reliable natural gas service to customers; and
- Risk mitigation.

In the table below, FEI describes its system level and site-specific risk mitigation actions to reduce the likelihood of a pipeline rupture from the both the threat of third-party damage and natural hazards.

Hazard	Primary Methods for How Risk is Mitigated for Existing Pipelines in Operation
Third-Party Damage	**Visual Inspection** FEI patrols its pipelines in order to visually detect activity that may cause third-party damage, including from: • Unpermitted activity in-progress; and • Visual right-of-way indications of prior unpermitted activity, such as disturbed or removed vegetation. **Vegetation Management** FEI's pipeline rights-of-way are also subject to vegetation management activities. Ensuring clear sight lines to identify the existence of pipelines is a key component of third-party damage prevention. Further, vegetation management activities provide clear access to FEI pipelines and facilities to maintain signage, conduct surveys, and other operations work in order to maintain the integrity of the pipeline system, in addition to managing the risks to FEI pipelines and facilities from hazard trees and root interactions.

Hazard	Primary Methods for How Risk is Mitigated for Existing Pipelines in Operation
	Signage Transmission pipeline rights-of-way are signed to identify the existence of buried pipelines and to provide contact information. **Public Awareness** FEI implements various public awareness activities, including BC 1 call advertising. **Management of Third-Party Activities** FEI implements a permits and inspection process for third-party activity in the vicinity of its pipelines, which establishes the parameters to enable third-party activity to proceed without adversely impacting the pipelines. **Depth-of Cover Monitoring** Depth-of-cover of transmission pipelines is periodically monitored. Site-specific hazard control measures such as the following have been implemented and will be planned as needed to reduce risk: 1. Signage (increased signage) to educate of the presence of the pipeline; 2. Physical barrier (e.g., Jersey barrier) to prevent activity above the pipeline; 3. Additional cover (e.g., additional soil) to protect the pipeline during activity; 4. Mechanical barrier (e.g., concrete slab) to protect the pipeline during activity; 5. Pipeline replacement to install a pipeline deeper and with current-year pipe impact resistance. **In-line Inspection and Condition Monitoring** For in-line inspected pipelines, FEI's in-line inspection activity can detect prior unreported and undetected third-party damage to the extent that metal loss (e.g., gouges) or geometric deformation (e.g., dents) has occurred that is within the detection threshold of the tool(s). For transmission pipelines that are not in-line inspected, FEI's condition monitoring of non-piggable pipelines can detect prior unreported and undetected third-party damage to the extent that coating and cathodic protection survey readings are influenced by the damage.
Natural Hazards (geotechnical, hydrotechnical and seismic hazards)	**Geotechnical and Hydrotechnical Hazards** • Identified geotechnical and hydrotechnical hazard sites on existing pipelines are subject to periodic monitoring. Hazard control measures, including repeat field inspections, detailed investigations, and mitigation, are planned and implemented at specific sites, as needed, to reduce risk. • Pipeline patrol can visually detect potential new geotechnical and hydrotechnical hazard sites. • For in-line inspected pipelines, strain analysis utilizing geometry tool (inertial mapping unit) data from successive runs can identify potential new geotechnical hazard sites. **Seismic Hazards** • FEI's transmission pipeline system is periodically assessed at the system level (e.g., regional studies) for potential site-specific susceptibility to seismic hazards. Hazard control measures, including pipeline replacement, are planned and implemented at specific sites, as needed, to reduce risk.

Please note that, as discussed in Section 3.4.4.1 of the Application, FEI's baseline system-level QRA was performed at the system level (general) as opposed to at the integrity management

level (specific). In accordance with the system-level approach, the estimates of rupture rate and risk are distributed along the overall length of the pipeline system and are more readily influenced by system level mitigation actions (e.g., pressure reduction to below 30 percent SMYS to mitigate the potential for rupture failures, pipeline replacement at increased burial depth). As such, site-specific mitigation will generally have limited impact on the system level estimates of rupture rate and risk as these types of mitigation actions tend to be applied to smaller segments of pipe.

FEI continues to evaluate, plan, and implement cost effective and practical incremental mitigation on a site-specific basis. As FEI evolves its risk management capabilities for future iterations of quantitative risk assessment, it anticipates improved capabilities to demonstrate the relative cost and safety benefits of potential risk mitigation measures for all threats, including third-party damage and natural hazards.

3.4 Please discuss how the ITS TIMC Project reduces the overall integrity risk to the ITS if it does not mitigate the threat of third-party damage or natural hazards.

Response:

The ITS TIMC Project is required to manage the risk associated with cracking on the eight ITS pipelines. As the risk associated with cracking threats contributes to the overall integrity risk on the ITS, reducing the risk associated with these threats will reduce its overall integrity risk.

The ITS TIMC Project is not intended to address risk associated with third-party damage or natural hazards as the risk associated with these, and other integrity threats, is already managed through FEI's integrity management and capital programs.

Please refer to the response to BCUC IR1 3.3 which summarizes the methods FEI uses to mitigate the threat of third-party damage and natural hazards.

4.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.5, p. 44

Planning Horizon for Completion of ITS TIMC Projects

On page 44 of the Application, FEI states:

> FEI has timed its CPCN applications for the two TIMC projects with consideration to the availability of proven and commercialized EMAT [electro-magnetic acoustic transducer] tools suitable for use in its transmission pipelines, and following its baseline QRA, which has informed the priority and urgency of the CTS and ITS TIMC projects. The ITS TIMC Project, if completed over a reasonable planning horizon as FEI is proposing, reflects an appropriate operator response to available information regarding the potential threat posed by pipeline cracking.

4.1 Please discuss how the availability of suitable EMAT tools factored in FEI's decision making process when determining a timeline for implementing the ITS TIMC Project.

Response:

The availability of proven and commercialized technology was a key factor in FEI's decision-making process when determining a timeline for initiating the TIMC projects. However, FEI's timeline for implementing the ITS TIMC Project, as outlined in the response to BCUC IR1 4.2, is not constrained by the availability of suitable EMAT tools. Please refer to the responses to BCUC IR1 1.2 and 1.2.1 for discussion on the drivers for the ITS TIMC Project and its proposed timeline.

As FEI indicated in multiple Annual Review proceedings dating back to 2016, FEI has been assessing "the need for and feasibility of adopting crack-detection capabilities within its in-line inspection program".[6] 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.

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",[7] dated September 30, 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

[6] FEI Annual Review for 2017 Rates, 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.

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

that now EMAT can be considered BAT [Best Available Technologies] for ILI crack detection in gas pipelines.

Although the above-referenced report was published over six years ago, it is indicative of the trend of EMAT ILI increasingly being adopted by industry. Further, as noted in the report, EMAT has now been under development for over 25 years.

While the maturity and capabilities of EMAT technology are continually evolving, another necessary consideration before implementation of EMAT technology is the commercial availability of tools suitable for FEI's natural gas pipelines. In particular, until recently, EMAT ILI tools were not commercially available for pipe diameters as small as NPS 10. Finally, as discussed in Section 3.2.3.3 of the Application, prospective ILI tools must be operable within the variable flow rates of FEI's system in order to be a suitable technology to implement.

4.2 Please confirm, or explain otherwise, that the execution of ITS TIMC Project events is scheduled in order of risk level.

4.2.1 If not, please explain, with reasons, how the execution order of ITS TIMC Project events is determined, including whether there are any other factors such as availability of EMAT tools or permitting that impacts project order.

4.2.2 If not, please explain whether there are increased project execution or safety risks if the projects are not prioritized in order of risk level. If so, please explain why FEI considers its Project event order selection to be appropriate.

Response:

Confirmed. The table below provides FEI's schedule for baseline EMAT ILI runs, which was developed based on the relative risk of cracking (i.e., the highest risk segments have been scheduled for EMAT ILI runs first). Therefore, the execution of ITS TIMC Project events has been phased first to complete alterations required to support EMAT ILI on the Savona to Penticton 323 mainline, followed by alterations to the remainder of pipelines.

Year	Mainline	Pipeline	Baseline Run
1	Savona to Penticton 323	SAV VER 323	2026
		VER PEN 323	2026
3	Penticton to Trail 273	PEN OLI 273	2028
		OLI GRF 273	2028
		GRF TRA 273	2028

Year	Mainline	Pipeline	Baseline Run
5	East Kootenay Link 323	YAH TRA 323	2030
7	Kingsvale to Oliver 323	KIN PRI 323	2032
		PRI OLI 323	2032

Of the eight ITS pipelines, the SAV VER 323 and VER PEN 323 pipelines have the highest estimated safety risk, so they were first to be scheduled. These pipelines also have the earliest occurring capacity limitations, which dictated the scheduled baseline EMAT ILI run in 2026. For these two pipelines, the Project execution schedule was also driven by this capacity constraint.

Further, system capacity requirements informed the duration between baseline runs. As concurrent pressure reductions on ITS mainlines cannot be performed without impacting customer supply or installing significant capacity upgrades, FEI plans to complete baseline runs two years apart to allow for potential pressure reductions on the inspected mainline and subsequent completion of crack repairs. If a pressure reduction is not required after a baseline run, the next baseline runs could be undertaken sooner.

5.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.3.3, pp. 40-41; Section 5.5, p. 114

Planning Horizon for Completion of ITS TIMC Projects

On page 40 of the Application, FEI provides the following description of JANA's analysis of SCC crack growth rates:

> This analysis was conducted in conjunction with Dr. Chen of the University of Alberta, a recognized SCC expert researcher. Software developed by Dr. Chen, called Pipe-Online, was used for the analysis of SCC crack growth behaviour and to predict the remaining lifespan of a pipeline prior to cracks growing to failure. The analysis utilized pressure data from 54 pipeline locations in the CTS and ITS, 8 FEI detailed field inspection reports from integrity digs, and a summary of SCC findings from 14 dig excavations.

5.1 Please provide the dates for the integrity dig information used in Dr. Chen's crack growth rate analysis.

Response:

The dates for the integrity dig information used in Dr. Chen's crack growth analysis range between 2000 and 2017, as shown in the data points plotted in Figures 3 and 4 of Confidential Appendix B-1.

On page 41 of the Application, FEI states:

> 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. [Emphasis added]

5.2 Please provide the reference year from which the "range of potential time until failure" is established (e.g. the year of Dr. Chen's analysis, the year(s) of integrity dig information, or another year).

Response:

The reference year from which the estimated range of potential time until failure in Dr. Chen's analysis is measured would be the years of integrity dig information used in the analysis, as these are the years in which the initial crack sizes evaluated by the study originated from. As noted in the response to BCUC IR1 5.1, the analysis was based on integrity dig information from between 2000 and 2017.

For clarity, Dr. Chen's analysis was used by FEI to inform the credibility of cracking threats on its transmission pipelines, not to identify a suitable mitigation timeframe. A suitable mitigation timeframe of any identified pipeline cracks can only be determined through quality pipeline condition data, such as the data collected through the use of EMAT ILI.

On page 114 of the Application, FEI states that initial Electro-Magnetic Acoustic Transducer In-Line Inspection (EMAT ILI) runs in the ITS are to begin 2026 following completion of the Project and that integrity digs for validation and repair will start shortly after the EMAT ILI run and may continue up to three years after the run.

5.3 Considering the estimated range of potential time until failure and the planning horizon for completion of the ITS TIMC project and validation of initial EMAT ILI runs, please discuss with reasons whether FEI considered expediting or delaying the project timeline.

5.3.1 If alternative project timelines were considered, please discuss whether there would be impacts to overall safety and project costs, and if so, what these impacts would be.

Response:

FEI did not consider expediting or delaying the project timeline as it did not consider it reasonable or necessary to do so. FEI has timed its initiation of the TIMC projects with consideration of the following:

- Availability of proven and commercialized technology suitable for use in FEI's transmission pipeline system. In particular, as described in the response to BCUC IR1 4.1, FEI initiated the TIMC projects in 2018 based on this factor;
- FEI's identification of emerging changes in industry practices including increasing adoption of EMAT ILI technology for managing cracking threats to transmission pipelines; and

- Completion of a baseline system-level QRA which has informed the priority and urgency of the TIMC projects and, in particular, informed FEI's timing of the CTS TIMC application relative to the ITS TIMC application. Please also refer to the response to BCUC IR1 4.2 for an explanation of how the baseline system-level QRA has informed FEI's schedule for executing ITS TIMC Project events.

Further, as described in the responses to BCUC IR1 1.2 and 1.2.1, without the OCU Project or another equivalent capacity improvement in-service, a delay in the ITS TIMC Project would further limit FEI's ability to respond to crack findings following the baseline EMAT ILI run on the Savona to Penticton 323 mainline.

As set out in the Application, it is necessary to ready the eight identified ITS pipelines for EMAT ILI tools capable of detecting cracking threats, such as SCC, which can lead to failure by rupture. Based on a baseline system-level QRA, FEI has determined that ITS pipelines are susceptible to cracking threats which, if not addressed, can lead to significant safety and reliability consequences. EMAT ILI tools are increasingly becoming the standard industry practice for mitigating cracking threats on pipelines and are the only technically and financially feasible alternative to mitigate such threats. FEI must adopt EMAT ILI for the eight identified ITS pipelines to keep pace with evolving industry practice and regulatory expectations for managing the safety risk posed by cracking threats, and to meet its obligations to ensure the safety and security of its pipeline operations.

Therefore, based on the available information and given that cracking is a time-dependent threat, for which the potential for failure increases over time, the ITS TIMC Project timeline as proposed in the Application is appropriate.

6.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.7, p. 46

Treatment of Smaller Diameter Transmission Pipelines

On page 46 of the Application, FEI states:

> FEI currently operates approximately 100 transmission pipelines with diameters NPS [nominal pipe size] 8 or smaller, which operate at a hoop stress level greater than 30 percent SMYS. Since EMAT tools are currently only commercialized and available for pipelines of diameter NPS 10 and larger, FEI did not include transmission pipelines with diameters smaller than NPS 10 in the scope of its TIMC projects. FEI will continue to inspect these pipelines for cracking during opportunity digs and, if significant cracking is discovered, it will develop a line specific mitigation plan.

6.1 Please explain whether cracking threats on FEI transmission pipelines with diameter smaller than NPS 10 could lead to failure by rupture.

Response:

Yes, cracking threats on transmission pipelines with diameters smaller than NPS 10 could lead to failure by rupture.

As explained in Section 3.5.3.1 of the Application, transmission pipelines operating above 30 percent of SMYS can fail by rupture due to time-dependent threats, which include cracking. This threat is independent of the pipelines' outside diameters.

6.2 Please discuss any assessments (either qualitative, semi-quantitative, or quantitative) to determine the risk of cracking on FEI's transmission pipelines with diameters smaller than NPS 10 and provide the result of these assessments.

Response:

In Appendix A4.19 of the QRA (page 60), filed as Confidential Appendix B-2 to the Application, FEI provided the baseline QRA risk assessment results for the TRA CAS 219 pipeline – which has a diameter smaller than NPS 10. This information was summarized in Table 3-4 of the Application as follows:

Table 3-4: FEI ITS Pipelines: Occurrences of Cracking on FEI Pipe Identified Through JANA's Review of Selected Integrity Digs and Total Integrity Digs Analyzed

#	Line Name	FEI Name	SCC Susceptibility	Seam Weld Cracking Susceptibility	Integrity Digs with Cracking Threats	Total Integrity Digs Analysed
6	TRA CAS 219	Trail – Castlegar 8"	Yes	Yes	11	76

While FEI has not prepared other assessments of the risk of cracking of FEI's transmission pipelines with diameters smaller than NPS 10 at this time, it recognizes that the potential for cracking exists for transmission pipelines of this size and confirms that its current crack management practices align with industry standard practice. Furthermore, FEI is committed to monitoring for continual improvement opportunities (i.e., technology development, evolution of industry practice) through its integrity management program.

6.2.1 Please compare the risk of cracking on FEI's transmission pipelines with diameters smaller than NPS 10 to the risk of cracking on FEI's transmission pipelines with diameters NPS 10 or greater.

Response:

A portion of this response is redacted pursuant to Section 19 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-178-22. The redaction has been made as it identifies vulnerable points on the Company's gas transmission system and areas of risk to FEI's assets. Disclosure of the detailed information could impede FEI's ability to work safely and to reliably operate its gas system assets and could risk the safety of both its workers and the public. A confidential version of this response is being filed with the BCUC and Interveners who have signed a Confidentiality Declaration and Undertaking.

As described in the response to BCUC IR1 6.2, FEI's baseline system-level QRA included only one pipeline with a diameter smaller than NPS 10 – the TRA CAS 219 pipeline. FEI has not undertaken other assessments of the risk of cracking of FEI's transmission pipelines with diameters smaller than NPS 10 at this time.

The table below summarizes the estimated safety risk and rupture rates of the TRA CAS 219 pipeline, which has a diameter smaller than NPS 10, and the GRF TRA 273 pipeline, which has a diameter of NPS 10 or greater and is geographically proximate and has similar construction attributes (e.g., similar years of construction). Please note that for the purposes of a baseline system-level QRA, NPS 8 and NPS 10 pipelines are considered to be reasonably similar comparators. As such, the results of this comparison show that the estimated risk and rupture

potential of these two pipelines is similar, with factors such as the relative length and pipeline diameter of the TRA CAS 219 pipeline contributing to its lower risk estimate, including the risk of cracking.

The information provided in the table below is excerpted from Confidential Appendix B-2 to the Application:

Irrespective of the similarity of this comparison, in the response to BCUC IR1 3.1.1, FEI explains that while pipeline diameter and surrounding population density are relevant factors, there are numerous other factors involved in estimating cracking risk. Therefore, FEI cannot estimate whether a QRA would estimate a higher, lower, or similar safety risk and rupture potential for transmission pipelines not included in the baseline system-level QRA.

Please note that, as discussed in the response to BCUC IR1 6.2.2, risk is not the sole factor in FEI's determination of appropriate integrity management mitigation.

6.2.2 If the risk of cracking is comparable across all ITS pipelines, please explain why FEI has not chosen to implement the same approach to mitigate the risk of cracking across all ITS pipelines (i.e. continue to inspect and develop line specific mitigation plans when required).

Response:

As explained in the response to BCUC IR1 6.2.1, FEI cannot estimate whether a QRA would estimate a higher, lower, or similar safety risk and rupture potential for transmission pipelines with diameters smaller than NPS 10 not included in the baseline system-level QRA. Further, as included in Section 3.4.4.1 of the Application, FEI considers a broad range of factors in its asset decision-making, which includes its determination to move to EMAT ILI technology for managing time dependent SCC on its transmission pipelines greater than NPS 10 in diameter. The factors include:

- Compliance obligations;
- Industry practice;
- Availability of proven and commercialized technology;
- Confidence in the degree of mitigation that can be achieved with a given mitigation alternative; and
- Financial considerations (e.g., cost, availability of resources).

While EMAT ILI is increasingly becoming an industry standard practice, reflecting its effectiveness in reducing the risk of pipeline rupture due to cracking, as explained in Section 3.2.3.3 of the Application, FEI is constrained by the commercial availability of technology for its pipelines with diameters smaller than NPS 10. The current limitation of EMAT ILI to pipelines of NPS 10 or greater was also affirmed in the independent report prepared by Dynamic Risk Assessment Systems, Inc., included as Appendix O-1 to the Application (Section E.6.4).

FEI will evaluate the use of EMAT ILI technology for smaller diameter pipelines when it becomes available, as it expects its industry peers will also do. In the interim, FEI considers practical and cost-effective steps it can take to facilitate the potential future adoption of EMAT tools in its smaller diameter pipelines. As an example, for laterals within the Inland Gas Upgrade (IGU) Project that have been selected for the ILI alternative, the project work facilitates the potential future adoption of EMAT tools.

6.3 Please explain why developing a line specific mitigation plan is an appropriate response, if significant cracking is discovered during an opportunity dig.

Response:

A line specific mitigation plan is the appropriate response given the localized nature of SCC cracking and the line-specific nature of many of the susceptibility and growth factors. Further, to ensure ongoing safe and reliable service, as well as to remain compliant with its regulatory obligations, FEI must assess any significant cracking discovered on its transmission pipelines whether identified through an opportunity dig, through EMAT ILI or as a result of failure. For example, Clause 10.3.2.1 of CSA Z662:19 states:

> Where the operating company becomes aware of conditions that can lead to failures in its pipeline systems, it shall conduct an engineering assessment to determine which portions can be susceptible to failures and whether such portions are suitable for continued service.

Similarly, Clause 10.3.2.2 of CSA Z662:19 states:

> Where an engineering assessment, the operating company's integrity management program, or observation indicates that portions of the pipeline system are susceptible to failures, the operating company shall either implement measures preventing such failures or operate the system under conditions that are determined by an engineering assessment to be acceptable.

Put simply, the primary purpose of a line specific mitigation plan is to prevent future failure(s).

6.4 Please identify any transmission pipeline where a line specific mitigation plan was implemented to manage cracking discovered during an opportunity dig.

Response:

To date, FEI has not identified any transmission pipeline where a line specific mitigation plan was warranted or implemented to manage cracking discovered during an opportunity dig.

Though no transmission pipelines have required a line specific mitigation plan to date, this does not mean that cracking does not exist on FEI's assets, or indeed, that FEI does not need to mitigate cracking on its system. As noted in Section 3.2.5 of the Application, FEI estimates that the total amount of pipeline exposed to date as part of its Integrity Dig Program (and thus assessed for cracking) is approximately one percent of the total length of pipe in FEI's transmission systems. As such, opportunity digs are not a means of effectively or efficiently identifying cases of cracking on a transmission pipeline, including those that could require the implementation of a site-specific mitigation plan.

6.4.1 Please explain how the line specific mitigation plan reduces the cracking risk.

Response:

A line specific mitigation plan mitigates cracking risk by reducing the likelihood of a future cracking failure and/or the potential consequences resulting from such a cracking failure.

As described in Section 4.3.3 of the Application, FEI could employ the following mitigation alternatives to reduce cracking risk as part of a line specific mitigation plan on pipelines with diameters NPS 8 or smaller:

- **Pressure Regulating Station (PRS):** PRS lowers the operating stress of the pipelines to below 30 percent of SMYS to reduce the potential consequences should a cracking failure occur.
- **Hydrostatic Testing Program (HSTP):** HSTP identifies and removes critical cracking threats from the pipeline to reduce the likelihood of future cracking failure.
- **Pipeline Replacement (PLR):** PLR provides a new pipeline to reduce the likelihood of future cracking failure. Further, if the new pipeline were designed to operate below 30 percent of SMYS, this would reduce the potential consequences should a cracking failure occur.
- **Pipeline Exposure and Recoat (PLE):** PLE provides a process to inspect the pipeline, remove sub-critical cracking threats, and recoat the pipeline. Removal of sub-critical cracking threats and recoating the pipeline both reduce the likelihood of future cracking failure.

7.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.7, p. 46; Section 3.5.2, p. 48

Regulatory Obligations to Mitigate Cracking Threats

On page 46 of the Application, FEI states:

> FEI currently operates approximately 100 transmission pipelines with diameters NPS 8 or smaller, which operate at a hoop stress level greater than 30 percent SMYS. Since EMAT tools are currently only commercialized and available for pipelines of diameter NPS 10 and larger, FEI did not include transmission pipelines with diameters smaller than NPS 10 in the scope of its TIMC projects. FEI will continue to inspect these pipelines for cracking during opportunity digs and, if significant cracking is discovered, it will develop a line specific mitigation plan.

On page 48 of the Application, FEI states that the BCOGC has provided written support for FEI's TIMC projects, "recognizing that it is in alignment with FEI's regulatory and legal responsibilities as a BCOGC permit holder."

7.1 Please discuss any regulatory requirements for FEI to assess cracking threats on its transmission pipelines with diameter smaller than NPS 10.

Response:

FEI is subject to many regulations that require it to manage the integrity of its transmission pipelines, including to assess cracking and other threats. These regulations are equally applicable to transmission pipelines of any diameter.

The BC *Oil and Gas Activities Act* (OGAA)[8] and the associated BC Pipeline Regulation (BC Reg. 147/2014)[9] and referenced standards make up the overarching regulatory requirements for the safe operation of transmission pipelines. 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.

In the table below, FEI identifies the relevant regulatory requirements associated with the integrity of its transmission pipelines.

[8] http://www.bclaws.ca/Recon/document/ID/freeside/00_08036_01.
[9] http://www.bclaws.ca/civix/document/id/complete/statreg/281_2010.

Regulatory Requirement	Discussion
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"[10]. 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 BCOGC 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. • FEI interprets its obligation under the BC Pipeline Regulation to "prevent spillage" as warranting consideration of industry practice, availability of appropriate technology, and the degree of confidence that can be achieved with a particular condition monitoring methodology.
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. • CSA Z662:19 3.1.2 f) v) states: "The safety and loss management system shall cover the life cycle of the pipeline system and shall include the following elements: f) controls for: v) pipeline system integrity management". • CSA Z662:19 3.3 states: "The controls required by Clause 3.1.2 f) v) shall be in the form of an integrity management program that addresses the life cycle of the pipeline system, as applicable."

10 "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	Discussion
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."	• FEI is obligated to assess its transmission pipelines for conditions that can lead to failures per CSA Z662:19 Clause 10.3.1 which states: "The pipeline system integrity management program required by Clause 3.3 shall include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data." This includes assessing cracking threats. • FEI is obligated to consider the use of ILI in its transmission pipelines per CSA Z662:19 Clause N.1.12.4 which states: "Consideration shall be given to using in-line inspection equipment to detect a) internal and external corrosion imperfections (see Annex D); b) dents; c) cracks; and d) excessive pipe movement." • FEI's consideration of the availability of appropriate technology is in accordance with informational notes to CSA Z662:19 Clause 9.9.6: "Techniques (e.g., the use of internal and external inspection equipment) to monitor the effectiveness of the corrosion control program shall be considered. Notes: 1) Guidelines for in-line inspection of piping for corrosion imperfections are contained in Annex D. 2) The factors to be reviewed when considering such inspection should include, but not be limited to, the following: a) the availability and capability of the equipment; b) the age, condition, and configuration of the piping; c) the service, leak, and corrosion mitigation history of the piping; and d) population density and environmental concerns." • 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.

EMAT ILI is the only feasible and cost-effective approach enabling an operator to detect areas along a pipeline that may warrant site-specific mitigation in alignment with its regulatory obligations. The subject of this Application is eight ITS pipelines that are *NPS 10 or greater* which JANA's analysis, included in the Application as Confidential Appendix B-1, determined were susceptible to SCC and for which ILI tools are available. While the TRA CAS 219 was identified as being susceptible to cracking, EMAT ILI tools are only commercially available for pipelines with diameters NPS 10 and larger, and therefore, FEI will continue to inspect these pipelines for cracking during opportunity digs.

7.2 Please explain whether FEI's plan to inspect smaller diameter transmission pipelines for cracking during opportunity digs is in accordance with standards and regulations or industry practice.

Response:

Yes, FEI's inspection of smaller diameter transmission pipelines for cracking during opportunity digs aligns with standards and regulations and industry practice.

As outlined in the response to BCUC IR1 7.1, standards and regulations require that FEI assess its transmission pipelines for conditions that can lead to failures. As discussed in the Application, FEI has identified cracking as a credible threat on eight ITS pipelines.

Further, it is an industry practice to assess cracking on non-EMAT-inspected pipelines through opportunity digs, unless significant cracking has been identified through prior digs or failure. In this case, a line specific mitigation plan would be adopted to supplement the existing integrity activities.

7.3 Please discuss any correspondence with the BCOGC regarding FEI's plans to mitigate cracking threats on smaller diameter transmission pipelines, which are not included in the TIMC projects.

Response:

FEI's submission in September 2021 to the BCOGC as part of its Compliance Assurance Process included the following: "Cracking or crack-like features are managed through opportunistic digs unless electromagnetic acoustic transducer (EMAT) data is available." FEI did not receive any direct feedback to this statement, beyond what is included in the response to BCUC IR1 2.1 and Attachment 2.1.1.

B. PROJECT DESCRIPTION

8.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 3.3.2, p. 31, Section 5.3, p. 91, Section 5.10, p. 114, Appendix R, p. 5; FEI CTS TIMC CPCN Proceeding, Exhibit A2-2, BCUC IR 1.1.4

ITS TIMC Project Scope

On page 5 of Appendix R of the Application, FEI states:

> As a means of furthering the conversation regarding incremental improvement in risk, FEI considers that the CPCN regulatory proceedings provide an effective and efficient process to assess and test the costs and benefits of a given project for ratepayers. The existing review of CPCN applications provides a fulsome opportunity for the BCUC and interveners to assess the need and justification of a project, alternatives to the project, and the project's costs and scoping. This assessment inherently incorporates considerations respecting risk mitigation, and importantly, the consequences of not undertaking incremental investments to address known risks.

On page 91 of the Application, FEI provides Table 5-4 which is reproduced below:

Table 5-4: Heavy-Wall Pipe Modification Scope

Pipeline	Event ID	Location	Type	Length of Heavy-Wall Pipe to be Replaced (m)	Length of Downstream Pipe Impacted by Speed Excursion (m)	Installation Technique for Replacement Segment
SAV PEN 323	1	SAVONA	Creek Crossing	60-80	193	Open Cut
KIN PRI 323	29	OKANAGAN SIMILKAMEEN	Pipe segment	Two segments of 2.5	112	Open Cut
KIN PRI 323	31	OKANAGAN SIMILKAMEEN	Valve assembly	15	223	Open Cut

On page 114 of the Application, FEI states in Table 5-7:

> If, once the validation digs are complete, there remain sections of the pipeline with deficiencies in the collected data (blind spots), FEI will evaluate the sections to determine whether further work needs to be done to ensure adequate risk identification and mitigation. This evaluation will be based on the following factors:
>
> 1. The severity of the data degradation;
> 2. The condition of the rest of the pipeline;
> 3. The percent coverage of the tool; and
> 4. The location of the blind spots.

Where required by the evaluation, discrete projects will be raised to mitigate SCC risk at these blind spots. A committee of FEI subject matter experts will determine the length of pipe that needs to be addressed and the method that will be applied to mitigate SCC. Integrity management methods including pipeline replacement (PLR) or pipeline exposure and recoat (PLE) may be used in localized applications where blind spots have occurred and where altering the pipeline to obtain high quality EMAT ILI data is not feasible…

Further in Table 5-7 on page 114 of the Application, FEI states that the timing of In-Ditch Inspection[s] of EMAT ILI Tool Blind Spots will be "2027 through 2035".

8.1 Please provide the total length of downstream pipe impacted by speed excursion as a percentage of the total length of the ITS pipelines.

Response:

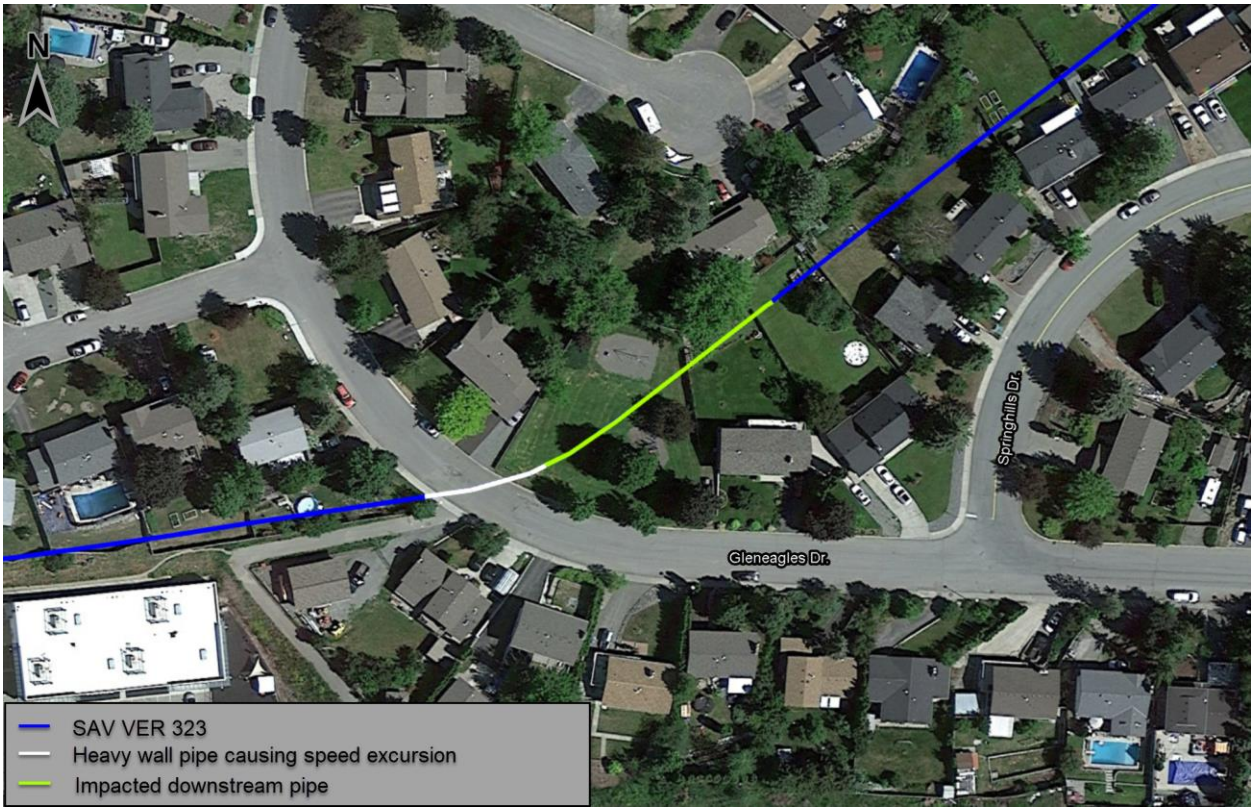
The following table provides the total length of downstream pipe impacted where previous MFL ILI tool runs exhibited speed excursions, including the three heavy wall locations proposed for replacement under the ITS TIMC Project, as a percentage of the total length of the ITS pipelines.

Pipeline ID	Approximate Length of Pipeline (km)	Approximate Length of Pipe Affected by Speed Excursions (m)	Percentage of Pipeline Impacted
SAV VER 323	143	576	0.40%
VER PEN 323	99	103	0.10%
GRF TRA 273	60	640	1.07%
OLI GRF 273	95	218	0.23%
PEN OLI 273	30	391	1.30%
KIN PRI 323	67	1152	1.72%
PRI OLI 323	95	221	0.23%
YAH TRA 323	163	94	0.06%

FEI requires full coverage for crack mitigation of the eight ITS pipelines. This is because a rupture of one of FEI's transmission pipelines at any location could cause unacceptable consequences as described in Section 3.5.3.2 of the Application and further in the response to CEC IR1 14.1. Thus, if the EMAT ILI tool experiences a speed excursion and cannot rely upon the data collected to make integrity decisions, then FEI will perform a site-specific assessment to determine a cost-effective mitigation.

The figure below provides an example of an MFL-C tool speed excursion that occurred in a residential area of Kamloops, whereby the tool travelled at velocities within the degraded specification range for approximately 57 metres following the heavy wall crossing pipe installed under Gleneagles Drive. Due to the short length of the speed excursion and considering that the

MFL-C tool did not travel over the maximum velocity for data collection, FEI chose to defer replacement of the heavy wall pipe at this location until after the EMAT ILI tool is run. However, if the EMAT ILI tool does experience a speed excursion at this location, or any other location, and FEI cannot rely upon the data collected to make integrity decisions, then FEI will perform a site-specific assessment to determine a cost-effective mitigation.



8.2 Please discuss the benefits and drawbacks of proactively modifying pipelines (heavy wall sections) to avoid speed excursions in comparison to modifying pipelines to address actual speed excursions identified after an EMAT ILI tool run.

Response:

FEI is proposing to proactively modify heavy wall sections in areas where excessive speed excursions (i.e., those exceeding the maximum tool velocity for data collection) have already been observed with MFL-C tools and at locations where the length of downstream pipe impacted was significantly longer than the heavy-wall pipe requiring replacement (see Table 5-4 of the Application). Running the EMAT ILI tool through the pipeline without replacing the identified heavy wall pipe segments will result in speed excursions, thus compromising the quality of data collected

by the tool, and/or compromising the ability of the tool to collect any data to assess the integrity of the pipe at these locations.

Proactively modifying the three proposed locations on the ITS will provide the following benefits:

- Early mitigation of cracking resulting from collection of high-quality EMAT data during the initial tool run.
- Ongoing collection of high-quality data by EMAT ILI and other in-line inspection tools (e.g., MFL) that allow for monitoring of pipeline integrity.
- Costs savings. In particular, if a speed excursion occurs resulting in the inability to collect reliable data, FEI will need to use another pipeline inspection method (e.g., expose and recoat the pipe) or replace the proposed heavy wall pipe and re-run the EMAT ILI tool to ensure the integrity of the pipeline. Given FEI's certainty that these three sections will cause data degradation, both alternatives would be ultimately more expensive compared to proactive pipeline modification at the proposed locations.

The potential drawback of proactively modifying pipeline sections would be the risk that a heavy wall section may not necessarily cause a speed excursion resulting in degraded data, or the length of pipeline downstream of the section with degraded data may be shorter than the proactive modification, resulting in some unnecessary work being performed. For this reason, FEI deferred certain pipeline alterations based on the results of the EMAT ILI Pilot Project (as summarized in Table 1 of Appendix D to the Application).

Importantly, based on its observations of EMAT ILI tool behaviour during the pilot project, FEI determined that there is a high probability of speed excursions occurring using EMAT ILI tools at the three locations in the Application where FEI has proposed proactive pipeline modification. As such, FEI does not see any drawbacks to proactively replacing these segments prior to an initial EMAT ILI run.

8.2.1 Please discuss the impact on overall costs to FEI should it decide to modify pipelines to address actual speed excursions identified after an EMAT ILI tool run.

Response:

Following the identification of a speed excursion after an EMAT ILI tool run, FEI would have two options should it decide to modify pipelines to ensure a complete understanding of the integrity of the pipeline with respect to cracking:

- **Option 1:** Replace the heavy-wall pipe causing the speed excursion and re-run the EMAT ILI tool; or
- **Option 2:** Develop another mitigation method, such as exposing and recoating or replacing the impacted segment of pipeline downstream of the speed excursion.

FEI will determine which of the two options is the most cost-effective and least impactful on a case-by-case basis based on the specifics of the speed excursion and local conditions.

Should FEI take a reactive approach instead at the three locations where FEI proposes to proactively modify the pipeline (i.e., the heavy-wall sections), both options would lead to increased overall costs.

- With Option 1, the additional cost would result from needing to re-run the EMAT ILI tool after replacement of the heavy-wall pipe to obtain quality data to validate the integrity of the pipeline with respect to cracking. Without the immediate re-run of the EMAT ILI tool, FEI would not understand cracking on the pipeline until the following run (approximately 7 years).
- With Option 2, the additional cost would result from needing to expose the pipeline and then either recoat or replace an incremental length of pipe. For example, the heavy-wall replacement under Event ID 31 is approximately 15 metres, whereas the downstream length of pipe impacted by the speed excursion in the MFL ILI tool was 223 metres, indicating that a potential additional 208 metres would require mitigation should Option 2 be selected.

8.3 Please discuss the likelihood of identifying deficiencies in EMAT ILI data obtained from future tool runs on ITS pipelines, despite the heavy wall pipe modifications proposed as part of this Project.

Response:

FEI considers it likely that it will identify deficiencies in EMAT ILI data obtained from future tool runs on ITS pipelines. As included in the response to BCUC IR1 9.1, the acceptability of an ILI tool run and corresponding data quality can be impacted by tool velocity, pipeline cleanliness, and tool performance. FEI takes prudent steps to mitigate the potential for deficiencies in EMAT ILI data, but recognizes that it is not possible to control the process to avoid all occurrences of EMAT ILI data deficiencies from future tool runs on ITS pipelines despite the modifications proposed as part of the Project.

8.4 Please explain the steps FEI will take in the event that EMAT ILI tool speed excursions occur at locations other than the three heavy-wall pipe sections identified above.

Response:

FEI will take the following steps if an EMAT ILI tool speed excursion is identified:

1. Review the data quality and determine whether the data can be relied upon for integrity decision-making. If the data can be relied upon, no further action will be taken to mitigate the speed excursion. If the data cannot be relied upon, then FEI will proceed to Step 2;
2. FEI's subject matter experts will identify and review the cause of the speed excursion (e.g., heavy-wall pipe, tight-radius bend, etc.) and determine the length of downstream impacted pipeline;
3. Based on the available information, integrity management methods to address the blind spot will be evaluated to select the most cost-effective solution (while still ensuring it is technically effective); and
4. The preferred integrity management method will then be implemented, and follow-on activities will be performed to ensure crack mitigation.

As noted on page 115 of the Application, FEI will request approval for selected integrity management solutions through an upcoming rate setting filing, depending on when these solutions are identified.

8.5 Please explain why FEI proposes to proactively modify the three identified heavy-wall pipe segments rather than follow the In-Ditch Inspection of EMAT ILI Tool Blind Spots procedure described in Table 5-7 for these three pipeline segments.

Response:

As noted on page 91 of the Application, FEI has proposed to proactively modify the three identified heavy-wall pipe segments due to the following considerations:

- **The severity of the speed excursion observed in the MFL-C tool:** The MFL-C tool exceeded the maximum velocity for data collection; and
- **The length of the downstream pipeline impacted by the MFL-C tool speed excursion**: The length of the pipe impacted by the speed excursion was significantly longer than the length of the heavy-wall feature causing the speed excursion. As such, it

would be more cost-effective to replace the shorter heavy-wall feature than to address the downstream impacted pipe post EMAT ILI run.

As described in Appendix D to the Application, there is observed related behaviour between the MFL-C and EMAT ILI tools indicating a high probability that EMAT tool speed excursions will occur at these three locations and that the speed excursion will be significant enough to prevent data collection, leaving the status of cracking on these segments of pipeline unknown. FEI has high confidence that proactive modification of these three heavy-wall segments is warranted and, ultimately, the most cost-effective means of assessing cracking threats at these locations on the pipeline.

On page 31 of the Application, FEI states:

> EMAT ILI is increasingly being adopted by industry for managing cracks and crack-like imperfections on transmission pipelines and enabling the mitigation of their potential for rupture.

In response to BCUC IR 1.1.4 in the CTS TIMC CPCN proceeding, Dynamic Risk stated:

> Dynamic Risk is not directly aware of any pipeline operators who have undertaken heavy wall pipe modifications specifically to avoid speed excursions. Such decisions and the necessity for proactive removal of wall thickness restrictions would be pipeline specific and in accordance with the nature and impact of wall thickness transitions, pipeline diameter, product velocity and product volumes. [Emphasis added]

8.6 Please explain if FEI is aware of any examples of pipeline operators who have made proactive heavy wall pipe modifications, similar to those currently proposed, to avoid the occurrence of EMAT ILI tool speed excursions.

Response:

FEI understands that other pipeline operators examine their systems prior to running in-line inspection tools with the intention of optimizing the potential for successful tool runs, including making proactive modifications to their pipeline system such as heavy wall modifications.

The following references provide an indication of the drivers for this behaviour, for FEI and others:

1. CSA Z662: All operators who are subject to the CSA Z662 standard, including FEI, must consider “degradation of data (e.g., inappropriate tool speed, debris, sensor failure)”[11]

[11] Excerpted from CSA Z662:19 Clause 10.10.1.1.

when assessing the acceptability of imperfections detected using ILI. Avoiding speed excursions facilitates an operator's assessment of ILI-reported imperfections; and

2. Rosen, a major in-line inspection vendor, including for EMAT tools, has published information on their website related to "Better Data Collection in Gas Pipelines".[12] This source states that "Gas pipelines have a variety of factors that can contribute to poor inspection run behavior resulting in low data quality. Although there are a variety of occurrences, the number one enemy to data quality are speed excursions." Further, one of the "Primary Factors" listed at this source is "Changes in wall thickness".

As discussed in Section 5.3 of the Application, degraded EMAT ILI data may result in incomplete coverage for crack mitigation on the eight ITS pipelines and require a reactive post-EMAT mitigation. As such, FEI, like other pipeline operators, takes prudent proactive steps, such as heavy-wall pipe modifications, to avoid the occurrence of EMAT ILI tool speed excursions that could lead to the unacceptable degradation of collected data.

8.7 Please discuss whether FEI considers proactive pipeline modifications to avoid speed excursions to be a typical industry practice.

Response:

Please refer to the response to BCUC IR1 8.6.

[12] https://www.rosen-group.com/global/solutions/services/better-data-collection-in-gas-pipelines.html.

9.0 Reference: PROJECT DESCRIPTION

Order C-3-22, Section 10.1, p. 60

Successful EMAT ILI Run Criteria

Page 60 of the CTS Decision and Order states:

> In an effort to improve regulatory efficiency and to allow for transparent testing of the assumptions made in developing project scope, the Panel expects FEI to provide, in its forthcoming ITS CPCN application, the criteria and metrics which it considers would define an acceptable EMAT ILI tool run and the basis for selecting these criteria and metrics. As an example of a criterion which could define an acceptable EMAT ILI tool run, FEI should provide its selected metrics for the acceptable pipeline length of discontinuous or continuous loss of pipeline integrity data for each pipeline segment undergoing an EMAT ILI run.

9.1 Please clarify whether the Application includes FEI's criteria and metrics which would define an acceptable EMAT ILI tool run. If yes, please provide a reference.

9.1.1 If not included in the Application, please explain why not.

Response:

Yes, the Application includes FEI's criteria and metrics which would define an acceptable EMAT ILI tool run. FEI has compiled the relevant information below.

As the acceptability of an EMAT ILI tool run is determined by whether the tool run has collected the intended data, FEI's acceptance of an EMAT ILI tool run is dependent on the presence of blind spots[13] and/or partially degraded data. FEI's criteria for an acceptable tool run are set out in the table below.

Criteria for an Acceptable EMAT ILI Tool Run	Metrics
Tool velocity	From Section 3 of Appendix F to the Application, typical velocities for EMAT ILI tools are: • Optimal Velocity Range: 1-2 m/s • Minimum Velocity: 0.1 m/s • Maximum Velocity for Full Resolution Data: 2 m/s • Degraded Specification Range: > 2 m/s and < 5 m/s • Maximum Velocity for Data Collection: 5 m/s Note: Actual velocity metrics will depend on the EMAT ILI tool vendor. Impact on data completeness and quality, if any, would require vendor's assessment upon completion of an EMAT ILI tool run.

[13] The term blind spots is intended as synonymous with other terms used in the ITS TIMC proceeding, including areas with fully degraded data or total loss of data.

Criteria for an Acceptable EMAT ILI Tool Run	Metrics
Pipeline cleanliness	Subjective evaluation in the field. The objective is to achieve clean pipelines for optimal sensor performance so that crack-like features can be detected and sized to the best of tool capability. There is no numeric specification for this.
Tool performance (e.g., sensor malfunction, battery failure)	Impact on data completeness and quality, if any, would require vendor's assessment upon completion of an EMAT ILI tool run.

9.2 Please provide the criteria and metrics which FEI has established to assess whether the data outputs from its future EMAT ILI tool runs are to be considered acceptable.

Response:

EMAT ILI tool vendors provide specifications for the detection and sizing of imperfections. FEI adopts these specifications as its criteria for assessing whether the data outputs from EMAT ILI tools are acceptable.

For example, the following table sets out the criteria and metrics from FEI's EMAT ILI tool run of the LIV PAT 457 pipeline as part of the EMAT ILI Pilot Project.

FEI's criteria to assess data outputs from an EMAT ILI tool run	Metrics
Tool meets vendor specification(s) for the detection of imperfections	Example from LIV PAT 457 EMAT ILI tool run, completed as part of the EMAT Pilot: • Preliminary analysis to report on cracking with depth greater than or equal to 50% of the total wall thickness (t) and length greater than or equal to 75 mm Note: Actual metrics for a future EMAT ILI tool run will depend on the specification(s) of the selected EMAT ILI tool.

FEI's criteria to assess data outputs from an EMAT ILI tool run	Metrics
Tool meets vendor specification(s) for the sizing of imperfections	Example from LIV PAT 457 EMAT ILI tool run, completed as part of the EMAT Pilot: • Axial cracks and axial crack-colonies within base pipe material: ○ Depth at 80% certainty ▪ for t < 10 mm (t < 0.39"): ± 15 % × t ▪ for t ≥ 10 mm (t ≥ 0.39"): ± 20 % × t ○ Length at 80% certainty ▪ ± 20 mm (0.79") • Axial cracks in longitudinal weld area ○ Depth at 80% certainty ▪ for t < 10 mm (t < 0.39"): ± 15 % × t ▪ for t ≥ 10 mm (t ≥ 0.39"): ± 20 % × t ○ Length at 80% certainty ▪ ± 20 mm (0.79") Note: Actual metrics for a future EMAT ILI tool run will depend on the specification(s) of the selected EMAT ILI tool.

9.2.1 Please compare FEI's successful EMAT ILI tool run criteria and metrics to the criteria and metrics used by other pipeline transmission industry companies.

Response:

While FEI does not have the specific criteria and metrics used by other transmission pipeline companies, it believes that other pipeline transmission companies have the same criteria as listed in the response to BCUC IR1 9.1. As the metrics for velocity and tool performance are vendor-specific and all assessments of pipe cleanliness are subjective and unique to the individual pipeline operators, the criteria and metrics of these companies may or may not match with FEI's metrics.

9.3 Please provide the maximum length of continuous degraded EMAT ILI tool run data that FEI considers to be acceptable.

9.3.1 Please provide evidence to support FEI's selection of its maximum acceptable length of continuous degraded EMAT ILI tool data criterion.

Response:

FEI has not established a maximum length of continuous or discontinuous degraded EMAT ILI tool run data. Instead, FEI reviews all instances of continuous or discontinuous lengths of pipeline with blind or degraded EMAT ILI tool run data on a case-by-case basis to establish next steps.

As noted in Section 5.3 of the Application, "FEI requires full coverage for crack mitigation on each of the 8 ITS pipelines. Where data has not been obtained or where degraded data with no specification has been obtained, FEI will perform a site-specific assessment to determine a cost-effective mitigation." As such, FEI will undertake a site-specific assessment of any areas where blind spots or where degraded data with no quality specification is provided by the EMAT ILI tool and will follow the steps included in the response to BCUC IR1 8.4.

For example, if FEI had a length of pipe with degraded data due to a speed excursion downstream of a heavy-wall road crossing, FEI would first evaluate whether the degraded data could be relied upon (e.g., if a degraded data specification is available). If the data cannot be relied upon, FEI would identify and review the cost effectiveness of various options such as:

- Replacing the heavy-wall road crossing pipe before a re-run of the EMAT ILI tool, to remove the cause of the speed excursion and prevent recurrence; and
- Exposing, evaluating, and re-coating the length of pipe with unusable degraded data downstream of the road crossing.

This is consistent with the process outlined by Dynamic Risk in the responses to CTS TIMC RCIA IR1 6.2 and 6.3 (included in Attachment O-2 of the Application):

> Any areas of degradation due to debris or overspeed would then be further overlaid with other data sets such as high consequence areas, previous ILI or proximity to crossings (as defined in the acceptance criteria) to determine if any reduced ILI performance specifications can be tolerated in those areas.
>
> […]
>
> Inspection with EMAT prior to the pipeline modifications will likely lead to blind spots and/or areas of data analyzed subject to a reduced ILI performance specification. The condition of the pipeline, with regards to crack features, in these areas would be unknown and require further investigation (excavation and inspection with NDE).

9.4 Please provide the maximum cumulative length of discontinuous degraded EMAT ILI tool run data that FEI considers to be acceptable.

9.4.1 Please provide evidence to support FEI's selection of its maximum acceptable length of discontinuous degraded EMAT ILI tool data criterion.

Response:

Please refer to the response to BCUC IR1 9.3.

9.5 Please discuss the EMAT ILI data quality acceptance process FEI will establish with its ILI service providers.

Response:

As noted in Table 5-7 of the Application, FEI will perform integrity digs to validate EMAT ILI data. Acceptance, interpretation and use of the EMAT ILI tool data is iterative and consists of a review of the data and then field validation. There may be multiple phases of integrity digs associated with the same EMAT ILI tool run, with the information gathered from the validation digs fed back into the data analysis.

FEI's approach is consistent with the process outlined in Section E.7.2 of Dynamic Risk's Independent Review of the CTS TIMC Project (Appendix O-1 of the Application) which states:

> The EMAT performance validation program is performed holistically where information from each inspection is continuously aggregated and reviewed to inform the complete validation process. Field excavations will be conducted throughout the course of the EMAT validation program and results will be continuously updated and analyzed over time.

9.6 Please explain how FEI will assess whether or not to accept an EMAT ILI tool run in the event that the tool run produces incomplete and/or degraded data.

Response:

Please refer to the responses to BCUC IR1 9.1 and 9.3 for FEI's acceptance process for EMAT ILI tool runs which includes considering and assessing the presence of incomplete (i.e., blind spots) and/or partially degraded data.

If an EMAT ILI tool run produces incomplete data for a length of pipeline, FEI will follow Steps 2 through 4 identified in the response to BCUC IR1 8.4. If there are partially degraded data outputs, FEI will follow Steps 1 through 4.

9.7 Please discuss whether ILI tool validation guidelines, such as CSA SPE-225.5:22 and/or API STD 1163, have informed FEI's development of this Project's scope as currently proposed and FEI's development of its overall EMAT ILI tool program. If so, please explain how and if not, please explain why not.

Response:

Validation guidelines, such as CSA SPE-225.5:22 "Metal loss inline inspection tool validation guidance" and API STD 1163 "In-line Inspection Systems Qualification", are valuable references for FEI's practices in validating the results of an in-line inspection run, including selection of tool validation digs and subsequent tool validation.

These guidelines have informed FEI's development of the ITS TIMC Project's scope and FEI's development of its overall EMAT ILI tool program. In particular, these validation guidelines further demonstrate that in-line inspection is a well-established integrity management method.

10.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.4.4.2, p. 97-98

Operating at Lower Operating Pressures

On pages 97-98 of the Application, FEI provides Table 5-5 reproduced below:

Station FID	Station Name	Operating Scenario	Scope of Modifications
13028	Savona Compressor Station	Savona to Penticton 323 mainline operating at 80% EOP	No modifications required
13102	SN-3 Control Station	Savona to Penticton 323 mainline operating at 80% EOP	No modifications required
13141	Armstrong Compressor Station	Savona to Penticton 323 mainline operating at 80% EOP	Add one pressure safety valve Modify four pressure switches Modify existing control systems
13273	SN 8-1 Valve Assembly	Savona to Penticton 323 mainline operating at 80% EOP	No modifications required
13280	SN 9-3 Control Station	Savona to Penticton 323 mainline operating at 80% EOP	No modifications required
13029	Oliver Y Control Station	Penticton to Trail 273 mainline operating at 80% EOP	No modifications required
		East Kootenay Link 323 pipeline operating at 80% EOP	
		Kingsvale to Oliver 323 mainline operating at 80% EOP	
13037	Warfield Compressor Station	Penticton to Trail 273 mainline operating at 80% EOP	Replace four pressure safety valves Modify existing control systems
		East Kootenay Link 323 pipeline operating at 80% EOP	
13065	Kitchener A Compressor Station	East Kootenay Link 323 pipeline operating at 80% EOP	Replace one pressure safety valve Modify eight pressure switches Modify existing control systems
13125	Hedley Compressor Station	Kingsvale to Oliver 323 mainline operating at 80% EOP	Replace one (1) pressure safety valve Modify existing control systems
13027	Kingsvale Compressor Station	Kingsvale to Oliver 323 mainline operating at 80% EOP	Replace two pressure safety valves Modify six pressure switches Modify existing control systems

10.1 Please explain if there will be any limits to meeting customer demand during operation at 80% of Established Operating Pressure. If so, please explain to what extent service to customers would be impacted under this operating scenario.

Response:

Pressure reductions resulting in operation at 80 percent of Established Operating Pressure (EOP) will not be performed concurrently on ITS mainlines. As such, FEI has considered its ability to meet customer demand if the mainlines are independently operated at 80 percent of EOP. The table below summarizes the potential impacts when each mainline is operated at 80 percent of EOP after the baseline EMAT ILI run. FEI provides further discussion in the table below.

Mainline	Pipeline	Operating Scenario	Impact on a Design Degree Day[14,15]
Savona to Penticton 323	SAV VER 323	Mainline operated at 80% EOP in 2026	Capacity shortfall of 1.5 MMSCFD
	VER PEN 323		
Penticton to Trail 273	GRF TRA 273	Mainline operated at 80% EOP in 2028	No impacts
	OLI GRF 273		
	PEN OLI 273		
East Kootenay Link 323	YAH TRA 323	Mainline operated at 80% EOP in 2030	No impacts (except to interruptible customers)
Kingsvale to Oliver 323	KIN PRI 323	Mainline operated at 80% EOP in 2032	FEI unable to deliver maximum load to CTS
	PRI OLI 323		

Note: FEI has assumed that the OCU Project will be in-service prior to baseline inspections of the Penticton to Trail 273 mainline, East Kootenay Link 323 pipeline and Kingsvale to Oliver 323 mainline.

1. **Savona to Penticton 323:** FEI will experience a capacity shortfall of 1.5 MMSCFD on a Design Degree Day (DDD) in 2026 if it is required to undertake a pressure reduction on the Savona to Penticton 323 mainline following the baseline EMAT ILI tool run. This assumes that FEI employs the operational strategy described in the response to BCUC IR1 1.2.1 to mitigate the absence of the OCU Project or another equivalent capacity project. FEI intends to secure the required 1.5 MMSCFD through negotiated temporary demand reductions with specific firm large-volume customers.

2. **Penticton to Trail 273:** There will be no customer impacts on a DDD if FEI is required to undertake a pressure reduction on the Penticton to Trail 273 mainline following the baseline EMAT ILI tool run.

3. **East Kootenay Link 323:** There will be no customer impacts on a DDD if FEI is required to undertake a pressure reduction on the East Kootenay Link 323 pipeline following the baseline EMAT ILI tool run. However, customers with interruptible loads would need to be impacted under warmer than usual weather conditions, which could affect their operations.

4. **Kingsvale to Oliver 323:** FEI will be unable to deliver the typical maximum load of 105 MMSCFD to the CTS if it is required to undertake a pressure reduction on the Kingsvale to Oliver 323 pipeline following the baseline EMAT ILI tool run. As described in Section 4.4.2.1 of the Application, the Kingsvale to Oliver 323 mainline is used to provide additional

[14] A design degree day represents an extreme average daily temperature (with a return period of 1-in-20 years) that FEI uses to assess peak gas demand requirements on gas distribution or transmission systems. FEI designs these systems to ensure minimum delivery pressures or better are maintained under peak demand to allow uninterrupted gas consumption for all firm customers served by the system.

[15] The design degree day for areas of the ITS being considered is 43.9, corresponding to an average daily temperature of -25.9°C.

gas to the CTS. Please refer to the response to CEC IR1 20.1 for further discussion on these impacts.

FEI expects that the need for pressure reductions following subsequent EMAT ILI runs on ITS mainlines, particularly those that would extend through a winter period, are less likely than would be required after the baseline run. This is because the baseline ILI results will allow FEI to complete initial crack repairs, as well as monitor and estimate future crack growth and plan its response to future potential cracking outside of peak demand periods.

C. FINANCIAL ANALYSIS

11.0 Reference: FINANCIAL ANALYSIS

Exhibit B-1, Section 6.4, pp. 119 - 121; Appendix D, p. 1; FEI CTS TIMC CPCN Application, Exhibit B-11, BCUC IR 47.3

ITS TIMC Development Cost Deferral Account

On page 119 of the Application, FEI states:

> As discussed in Section 1.2.2, FEI received BCUC approval with BCUC Order G-237-18, granting the creation of the non-rate base TIMC Development Cost deferral account. The deferral account was approved to attract a WACC return, with disposition to be proposed in a future application. Costs captured in the TIMC deferral account include the Application Costs, the Preliminary Stage Development Costs, and the Pre-Construction Development Costs.

On page 120 of the Application, FEI states:

> Preliminary Stage Development Costs are related to expenses incurred for engaging third party consultants for feasibility evaluation, preliminary development, and assessment of the potential design for the TIMC projects (both CTS and ITS). It also consists of the QRA of FEI's transmission pipeline assets and the EMAT ILI Pilot project costs.
>
> […]
>
> The pre-construction development costs associated with the ITS TIMC Project will be capitalized by transferring to construction work-in-progress (CWIP);

On page 121 of the Application, FEI shows Table 6-4 reproduced below:

Table 6-4: Summary of ITS TIMC Deferral Costs for Application and Development ($millions)

Line	Particular	2021	2022	2023	Total
1	Application Costs	0.002	0.228	0.170	0.400
2	ITS Preliminary Stage Development Costs	-	-	-	-
3	ITS Pre-Construction Development Costs (Capitalized)	2.556	0.829	0.279	3.665
4	**Subtotal, Pre-Tax Costs[1]**	**2.558**	**1.057**	**0.449**	**4.065**
5	Financing, WACC Return	0.043	0.133	0.177	0.353
6	Income Tax Recovery	(0.691)	(0.147)	(0.046)	(0.883)
7	**Subtotal w/ Financing & Income Tax Recovery**	**1.911**	**1.043**	**0.581**	**3.535**
8	Less: Cost Capitalized (Incl. AFUDC)	-	(3.619)	(0.489)	(4.108)
9	**Total Deferral Costs**	**1.911**	**(2.576)**	**0.092**	**(0.574)**

Note 1: Total of Line 4 agrees with Table 5-2, Line 4 + Line 5

11.1 Please explain why there are no preliminary stage development costs associated with the ITS Project.

Response:

There are no preliminary stage development costs associated with the ITS TIMC Project because the preliminary stage development activities completed for the CTS TIMC Project were also applicable to the ITS TIMC Project and did not need to be duplicated. As described on page 120 of the Application and referenced in the preamble above, the preliminary stage development costs are intended for feasibility evaluation as well as preliminary development and assessment of potential design options for the project. Given the similarities of the CTS and ITS Projects, FEI avoided incurring additional preliminary stage development costs specifically for the ITS TIMC Project and instead leveraged the work that was already available from the CTS TIMC Project. The costs associated with this work are captured in the non-rate base TIMC Development Cost deferral account which was approved by Order C-3-22 to transfer to rate base and commence amortization on January 1, 2023.

As discussed in the responses to BCUC IR1 27.4 and CEC IR1 35.1 in the CTS TIMC Project CPCN proceeding, all initial QRA and EMAT ILI Pilot Project costs were allocated to the CTS TIMC Project despite the costs covering both the CTS and ITS pipelines. This is because the entirety of the EMAT ILI Pilot Project was required to define and inform the CTS TIMC Project. Furthermore, as discussed in Appendix D of the Application, FEI was able to further leverage the information generated by the initial Pilot Project to inform the ITS TIMC Project without the need to undertake further work or incur further costs. Given these costs are already captured in the non-rate base TIMC Development Cost deferral account and were transferred to rate base on January 1, 2023 to commence amortization, there are no costs related to the initial QRA as well as the EMAT ILI Pilot Project to be captured in the deferral account for the ITS TIMC Project.

FEI also clarifies that the $3.665 million shown on Line 7 of Table 6-1 of the Application are for pre-construction development work that is specific to the ITS TIMC Project (i.e., not shared with the CTS TIMC Project). Consistent with the approval for the CTS TIMC Project in Order C-3-22, FEI will be capitalizing these costs, i.e., transferring the costs from the non-rate base TIMC Development Costs deferral account to construction work-in-progress.

11.2 Please explain how FEI determines the allocation of total costs of $3.535 million (Line 7 in Table 6-4) of which $4.108 million is to be capitalized (Line 8 in Table 6-4) and $0.574 million credit is to be transferred from the existing non-rate base TIMC Development Cost deferral account to the existing rate base TIMC Development Cost deferral account.

11.2.1 As part of the response, please discuss how it is reasonable that FEI capitalize more costs ($4.108 million) than there is of the total cost ($3.535 million).

11.2.2 Please explain all costs, including the pre-construction development costs of $3.665 million, that will be capitalized as part of the total $4.108 million amount.

Response:

FEI notes that the costs captured by the non-rate base TIMC Development Cost deferral account for the ITS TIMC Project include both Application costs and pre-construction development costs. The pre-construction development costs include front-end engineering and design, environmental assessments, Indigenous engagement, and stakeholder consultation work that are specific to the ITS TIMC Project. Consistent with the approved treatment in the CTS TIMC Project CPCN (Decision and Order C-3-22), these costs (including the associated financing costs at FEI's WACC) are capitalized, i.e., transferred from the non-rate base TIMC deferral account to construction work-in-progress (CWIP). The remaining costs, which are the Application costs (including the associated financing costs at FEI's WACC) and the income tax recovery associated with the Application costs as well as the pre-construction development costs will be transferred to rate base on January 1 of the year following a BCUC decision on the ITS TIMC Project.

FEI clarifies that there are not more costs being capitalized (i.e., $4.108 million) than are forecast to be incurred (i.e., $3.535 million) as suggested by this information request. The $3.535 million shown on Line 7 of Table 6-4 of the Application are the net additions to the deferral account which include the financing costs and the income tax recoveries for both the Application costs and the pre-construction development costs. On the other hand, the $4.108 million shown on Line 8 of Table 6-4 are related to the pre-construction development costs incurred plus the associated financing costs only; the amount does *not* include any associated income tax recovery. FEI notes that for tax purposes, the pre-construction development costs incurred prior to capitalization (i.e., transferred to CWIP) are considered as expenses which would be eligible for income tax recovery and therefore will remain in the deferral account to be transferred to rate base as a credit on January 1 of the year following a BCUC decision on the ITS TIMC Project. As such, by capitalizing only the pre-construction development costs and the associated financing costs but leaving the income tax recovery, it resulted in the non-rate base TIMC Development Costs deferral account being in a credit position of $0.574 million (i.e., Line 9 of Table 6-4 of the Application).

Please refer to Table 1 below which provides a continuity of the Application costs and pre-construction development costs, including the calculation of the income tax recovery as well as the costs capitalized to CWIP. It can be seen that the resulting closing balance in 2023 of the deferral account is estimated to be a credit of $0.574 million (i.e., Line 16 in 2023) which aligns with Line 9 of Table 6-4 of the Application. Table 1 below also shows that the total pre-construction costs capitalized at the end of 2023 are estimated to be $4.108 million (i.e., Line 23 in 2023) which aligns with Line 8 of Table 6-4 of the Application, and the total net costs captured by the deferral

account, including all costs to be capitalized (i.e., prior to being transferred to CWIP) plus the associated financing costs and all income tax recovery is $3.535 million (i.e., Line 7 in 2023) which aligns with Line 7 of Table 6-4 of the Application.

Table 1: Continuity of ITS TIMC Project Deferral Costs and Pre-construction Development Capitalized Costs ($ millions)

Line	Particular	Reference	2021	2022	2023
1	**Application Costs**				
2	Opening Balance	Prior Year: Line 6	-	0.002	0.169
3	Additions	Table 6-4 of Application (Line 1)	0.002	0.228	0.170
4	Income Tax Recovery	-Line 3 x 27%	(0.001)	(0.061)	(0.046)
5	Financing Costs	At FEI's WACC	0.000	0.002	0.014
6	**Closing Balance - Application Costs**	**Sum of Line 2 to Line 6**	**0.002**	**0.169**	**0.308**
7					
8	**Pre-Construction Costs**				
9	Opening Balance	Prior Year: Line 14	-	1.909	(0.835)
10	Additions	Table 6-4 of Application (Line 3)	2.556	0.315	-
11	Income Tax Recovery	-Line 10 x 27%	(0.690)	(0.085)	-
12	Financing Costs	At FEI's WACC	0.043	(0.019)	(0.046)
13	Less: Capitalized Costs		-	(2.955)	-
14	**Closing Balance - Pre-Construction Costs**	**Sum of Line 9 to Line 14**	**1.909**	**(0.835)**	**(0.881)**
15					
16	**Total Closing Balance of Deferral Costs**	**Line 6 + Line 14**	**1.911**	**(0.665)**	**(0.574)**
17					
18	**Capitalized Costs**				
19	Opening Balance	Prior Year: Line 23	-	-	3.619
20	Opening Balance - Transfer from Deferral	-Line 13	-	2.955	-
21	Additions	Table 6-4 of Application (Line 3)	-	0.514	0.279
22	Financing Costs	At FEI's WACC	-	0.150	0.210
23	**Closing Balance - Capitalized Costs**	**Sum of Line 19 to Line 23**	**-**	**3.619**	**4.108**
24					
25	**Total Deferral Costs (Incl. Capitalized Costs)**	**Line 16 + Line 23**	**1.911**	**2.954**	**3.535**

In response to BCUC IR 47.3 in the FEI CTS TIMC CPCN Proceeding, FEI provides a table showing the breakdown between the quantitative risk assessment (QRA) costs, CTS TIMC development costs, ITS TIMC development costs and the development costs that were capitalized as proposed in the FEI CTS TIMC CPCN Application, reproduced below:

Amounts in ($000s)	Original Estimate	Actual Spend	Projected Remaing Spend	Total Actual & Projected Costs
CTS Development Costs - deferral		2,701	6,117	8,818
CTS Development Costs - capitalized		9,340	3,907	13,247
CTS Carrying Costs		233	257	490
Total CTS Costs		**12,274**	**10,281**	**22,555**
ITS Development Costs	-	-	6,050	6,050
ITS Carrying Costs	-	-	351	351
Total ITS Costs	**-**	**-**	**6,401**	**6,401**
QRA Costs		11,700	-	11,700
QRA Carrying Costs		1,011	341	1,352
Total QRA Costs	**-**	**12,711**	**341**	**13,052**
Combined CTS, ITS, & QRA Costs (After Carrying Costs)	**41,600**	**24,985**	**17,023**	**42,008**

11.3 Please reconcile the total ITS costs shown in Table 6-4 in the Application of $3.535 million with the ITS costs shown in the FEI CTS TIMC CPCN Application of $6.401 million.

Response:

The $6.401 million referenced in this IR was a forecast that was developed by FEI at the time of responding to BCUC IR2 47.3 in the CTS TIMC Project proceeding and was therefore prepared in the latter half of 2021 (the IR2 responses were filed with the BCUC on October 7, 2021). The amounts shown in Table 6-4 of this Application are updated forecasts based on the information available at the time of filing the Application on September 20, 2022 and include actual spending up to August 2022. Based on the updated information, FEI reduced its forecast of ITS TIMC development costs by $1.983 million, resulting in a lower forecast amount of $4.418 million.

FEI also notes that the original forecast of $6.401 million provided in the response to BCUC IR2 47.3 in the CTS TIMC Project proceeding represents the gross additions plus financing costs and therefore does not include any income tax recoveries. On the other hand, as explained in the response to BCUC IR1 11.2, the $3.535 million shown on Line 7 of Table 6-4 of the Application (and referenced in this IR) represents the net costs captured by the non-rate base TIMC Development Costs deferral account and therefore includes all income tax recoveries associated with both the ITS TIMC Project Application costs and the pre-construction development costs. Therefore, to provide the appropriate comparison, FEI has referred to the gross additions to the ITS TIMC Project deferral account of $4.418 million in the above paragraph of this IR response. Consistent with the original forecast of $6.401 million, the updated forecast of $4.418 million includes Application costs and pre-construction costs plus the associated financing costs (i.e., $4.065 million on Line 4 of Table 6-4 of the Application plus $0.353 million on Line 5 of Table 6-4) but does not include any income tax recoveries.

On page 1 of Appendix D of the Application, FEI states:

> FEI identified two pipeline segments where it could undertake necessary system improvements within timelines practical to inform the development of the CTS and ITS TIMC Projects. This approach enabled FEI to incorporate further refinements and certainty into the scope and requirements of the projects. As such, FEI proceeded with the required alterations and baseline EMAT inspection of these two pipeline segments through a pilot project to inform FEI's development of the Projects.

11.4 Please discuss the cost of the EMAT ILI Pilot project, including the amount and how the costs were allocated between the CTS and ITS TIMC Projects.

11.4.1 As part of the response, please explain how the "Preliminary Stage Development Costs" which "consists of the QRA of FEI's transmission pipeline assets and the EMAT ILI Pilot project costs" shown in Table 6-4 of the Application with nil value captures the EMAT ILI Pilot project costs, if any. If there are no EMAT ILI Pilot project-related costs for the ITS Project, please explain why not.

Response:

FEI clarifies that the statement in Appendix D of the Application and referenced in the preamble above was intended to convey that the knowledge gained from the EMAT ILI Pilot Project helped to inform the development of both the CTS and ITS TIMC Projects.

The two pipelines that were part of the EMAT ILI Pilot Project are both CTS pipelines, i.e., Livingston-Pattullo 18" pipeline (LIV PAT 457) and Cape Horn-Burrard 20" pipeline (CPH BUR 508) as described in Section 5.3.3 of the CTS TIMC application. As such, all of the costs associated with the EMAT ILI Pilot Project were included as development costs in the CTS TIMC Project; there are no Pilot Project costs allocated to the ITS TIMC Project.

With regard to the cost of the EMAT ILI Pilot Project, please refer to the response to BCUC IR1 11.1.1 in the CTS TIMC Project proceeding, which showed that the total cost of the Pilot was approximately $7.4 million. Of this $7.4 million, approximately $4.2 million was capitalized and approximately $3.2 million was transferred to the rate base TIMC Development Cost deferral account on January 1, 2023.

Please also refer to the response to BCUC IR1 11.1 (in the current proceeding) which further explains why there are no preliminary stage development costs, including the QRA, associated with the ITS TIMC Project.

12.0 Reference: FINANCIAL ANALYSIS

Exhibit B-1, Section 5.4, p. 96; Exhibit B-1, Section 6.3, pp. 117 – 119; Exhibit B-1, Section 6.4, p. 119

Sustainment Capital and PRS

On page 117 of the Application, FEI states:

> The 70-year analysis period is based on a 65 year post-project analysis period (from 2027 as all assets, except for the closing costs, are estimated to be placed in-service by 2026) plus five prior years for the estimated Project schedule from 2022 to 2026.

On page 118 of the Application, FEI shows Table 6-3: Financial Analysis of the Project, reproduced below:

Table 6-3: Financial Analysis of the Project

Line	Particular	TOTAL	Reference (Confidential Appendix J, Financial Schedule)
1	Total Charged to Gas Plant in Service ($ millions)	85.161	Schedule 6, Sum of Line 43 (2022-2027)
2	Total Project Deferral Costs, Net of Tax	(0.574)	Schedule 9, Line 8 (2023)
3	***Total Project Cost - Excl. Sustainment Capital ($ millions)***	***84.588***	***Line 1 + Line 2***
4	Sustainment Capital	103.062	Schedule 6, Sum of Line 43 (2028-2091)
5	***Total Project Cost - incl. Sustainment Capital ($ millions)***	***187.650***	***Line 3 + Line 4***
6			
7	Incremental Rate Base in 2028 ($ millions)	81.004	Schedule 5, Line 19 (2028)
8	Incremental Revenue Requirement in 2028 ($ millions)	6.860	Schedule 1, Line 11 (2028)
9	***PV of Incremental Revenue Requirement 70 years ($ millions)***	***93.621***	***Schedule 10, Line 25***
10	Net Cash Flow NPV 70 years ($ millions)	4.227	Schedule 11, Line 17
11			
12	Delivery Rate Impact in 2028 (%)	0.72%	Schedule 10, Line 28 (2028)
13	***Levelized Delivery Rate Impact 70 years (%)***	***0.54%***	***Schedule 10, Line 32***
14	Levelized Delivery Rate Impact 70 years ($/GJ)	0.027	Schedule 10, Line 45

On pages 118 and 119 of the Application, FEI states:

> Incremental Sustainment Capital: The financial analysis over the 70-year period included the future replacement costs of the station's telemetry and the measuring & regulating equipment. The timing of the replacement costs is based on the average service life of the telemetry and the measuring & regulating equipment, which is 11 years and 47 years, respectively, as detailed in FEI's most recently approved Depreciation Study;

On page 119 of the Application, FEI states:

> Once the assets are placed into service, the associated capital cost will enter rate base as part of the opening balance in the appropriate plant asset accounts, for inclusion in FEI's rate base on January 1 of the following year.

12.1 Please confirm, or explain otherwise, whether FEI expects to incur sustainment capital costs between 2022 to 2028 and refer to Schedule 6 in Appendix J as appropriate.

12.1.1 If confirmed, please explain why the Sustainment Capital Reference in Table 6-3 states the period is for "2028-2091" and not starting from 2022.

12.1.2 Please explain whether there are any sustainment capital costs incurred from years 2022 to 2028 included in the calculation for the Delivery Rate Impact in 2028 of 0.72% as shown in Table 6-3.

Response:

Not confirmed.

FEI clarifies that the numbers from 2022 to 2027 shown on Line 43 of Schedule 6 in Appendix J, which sum to $85.161 million, are the estimated capital costs of the ITS TIMC Project. Given all assets resulting from the ITS TIMC Project are estimated to be placed in-service by 2027 (i.e., included in FEI's rate base by January 1, 2028)[16], there would be no incremental sustainment capital resulting from the ITS TIMC Project prior to and in the year of the assets entering FEI's rate base, i.e., from 2022 to 2028. As such, there are no incremental sustainment capital costs included between years 2022 and 2028 on Line 43 of Schedule 6 in Appendix J, and the 0.72 percent delivery rate impact in 2028 shown in Table 6-3 of the Application does not include any incremental sustainment capital from 2022 to 2027 due to the ITS TIMC Project.

FEI further notes that, for the purpose of the financial analysis over the 65-year post-Project period, FEI included incremental sustainment capital due to the ITS TIMC Project from 2028 to 2091, i.e., after the new assets resulting from the ITS TIMC Project have entered FEI's rate base. Please refer to the response to BCUC IR1 12.2 for a discussion of the incremental sustainment capital from 2028 to 2091, which sums to $103.062 million as shown on Line 4 of Table 6-3 as referenced in the preamble above.

For further clarity, FEI will incur sustainment capital between 2022 and 2027 on its natural gas system overall, but there is no sustainment capital specifically resulting from the ITS TIMC Project. The financial analysis, and specifically Schedule 6 in Appendix J, reflects only the costs associated with the ITS TIMC Project.

12.2 Please confirm, or explain otherwise, that the Sustainment Capital cost of $103.062 million is included in (i) the financial analysis over the 70-year period for

[16] As discussed in Section 6.5 of the Application, assets will be placed in-service over multiple phases from 2025 to 2027.

the Project, (ii) the calculation for the Delivery Rate Impact in 2028 of 0.72% and (iii) the calculation for the Levelized Delivery Rate Impact 70 years of 0.54% as shown in Table 6-3.

Response:

Consistent with FEI's presentation and treatment in its other CPCN applications, FEI distinguishes between the cost of undertaking the project, and the ongoing sustainment costs that will be incurred as a result of the project being in rate base; however, both of these types of costs are considered in the financial analysis over the life of the assets that is included in FEI's CPCN filings. As such, FEI confirms that (i) and (iii) are correct, but does not confirm (ii), as further explained below.

With regard to (i), FEI confirms that the sustainment capital cost of $103.062 million is included in the financial analysis of the ITS TIMC Project over the 70-year analysis period.

With regard to (ii), it is not confirmed that the sustainment capital cost of $103.062 million is included in the delivery rate impact of 0.72 percent in 2028. The delivery rate impact of 0.72 percent in 2028 is the impact related to all of the ITS TIMC Project capital costs (i.e., costs incurred for the Project prior to 2028) entering rate base by January 1, 2028. For clarity, as discussed in Section 6.5 of the Application, all capital assets associated with the Project are estimated to be placed in-service by 2027; therefore, consistent with FEI's treatment of CPCN capital costs, the costs will enter rate base on January 1 of the following year, i.e., 2028.

With regard to (iii), FEI confirms that the levelized delivery rate impact of 0.54 percent over the 70-year analysis period includes the sustainment capital costs of $103.062 million. As discussed on pages 118 and 119 of the Application, the incremental sustainment capital, totaling to $103.062 million from 2028 to 2091, is related to the future replacement costs for the telemetry assets and the measuring & regulating equipment that were installed and placed in-service as part of the ITS TIMC Project. FEI notes that, consistent with the CTS TIMC Project approved by Decision and Order C-3-22[17], these replacement costs are not part of the ITS TIMC Project and FEI is not seeking approval for these future potential replacement costs as part of this Application. If these replacement costs materialize in the future, FEI will seek BCUC approval for these costs in a future application (in a future revenue requirement application) and will file a CPCN application if the magnitude of the costs exceeds the CPCN threshold set by the BCUC.

FEI further clarifies that the sustainment capital costs are included in the financial analysis as a proxy for future potential capital costs due to the ITS TIMC Project over the 70-year analysis period since the telemetry assets and the measuring & regulating equipment will be fully depreciated in 11 years and 47 years, respectively, based on the average service life of these assets in FEI's most recent depreciation study.[18] In other words, the financial analysis as well as

[17] Page 35 of Decision and Order C-3-22.
[18] FEI's 2017 Depreciation Study, approved as part of the 2020-2024 MRP Decision and Order G-165-20.

the levelized delivery rate impact presented in the Application conservatively reflects the total potential impact due to the ITS TIMC Project over a 70-year period, as opposed to the financial and delivery rate impact for just the initial Project capital costs.

Please refer to Table 1 below which shows the estimated costs and schedule for these future potential capital costs included in the financial evaluation over the 70-year period. As noted above, the schedule is based on the average service life from FEI's most recent depreciation study for the asset classes of transmission telemetry and transmission measuring & regulating equipment, which is 11 years and 47 years, respectively. For example, the financial analysis assumes the telemetry assets installed due to the ITS TIMC Project will be fully depreciated in 11 years and will be replaced every 11th year over the 70-year analysis period. FEI also notes that the estimated cost for these potential future replacements is based on the initial cost of these assets as part of the ITS TIMC Project escalated into future dollars with inflation. For example, the initial telemetry costs estimated to be in-service in 2025 are $3.447 million (Confidential Appendix J, Schedule 7, Line 9); therefore, a proxy of future replacement costs of $4.285 million (i.e., $3.447 million plus 2 percent annual escalation over 11 years) is included in the financial evaluation in year 2036 when the original cost of $3.447 million is fully depreciated.

Table 1: Estimated Costs and Schedule of Future Potential Replacement Costs included in the Financial Analysis for the ITS TIMC Project over a 70-year period ($000s)

Line	Particular	Reference	2036	2037	2047	2048	2058	2059	2069	2070	2072	2073	2080	2081
1	46710 Measuring & Regulating - Stations	Conf App J; Sch 6, Line 26									13,112	15,141		
2	46720 Telemetry - Stations	Conf App J; Sch 6, Line 27	4,285	4,948	5,328	6,153	6,625	7,650	8,237	9,512			10,242	11,827

12.3 Please provide a breakdown of the sustainment capital and replacement costs required for telemetry, measuring and regulating equipment.

Response:

Please refer to the response to BCUC IR1 12.2.

12.4 With reference to the future replacement costs of the station's telemetry and the measuring & regulating equipment in the preamble above on pages 118 and 119 of the Application, please clarify what "station" FEI is referring to.

Response:

FEI clarifies that the stations referenced in the preamble refer to the 13 "stations" (or facilities) that are within the scope of the ITS TIMC Project as listed in Table 5-3 of the Application.

12.4.1 Please discuss the delivery rate impact in the years where there is a replacement of the station's telemetry and the measuring & regulating equipment.

Response:

Please refer to Table 1 below showing the estimated delivery rate impact (when compared to 2022 Approved) and the year-over-year change in delivery rates in those years where a proxy of future replacement costs for the station's telemetry and measuring & regulating equipment are included in the financial analysis over the 70-year period. FEI notes that, as discussed in the response to BCUC IR1 12.2, FEI is not seeking approval for these future replacement costs as part of the ITS TIMC Project. The delivery rate impacts shown in Table 1 below are for illustration purposes and to evaluate the impact of the ITS TIMC Project over a 70-year analysis period.

Table 1: Delivery Rate Impacts due to Future Potential Replacement Costs of Telemetry and Measuring & Regulating Equipment

Line	Particulars	Reference	2036	2037	2038	2047	2048	2049	2058	2059	2060
1	46710 Measuring & Regulating - Stations ($000s)	BCUC IR1 12.2	-	-	-	-	-	-	-	-	-
2	46720 Telemetry - Stations ($000s)	BCUC IR1 12.2	4,285	4,948	-	5,328	6,153	-	6,625	7,650	-
3	Delivery Rate Impact (%) when compared to 2022 Approved		0.72%	0.74%	0.76%	0.67%	0.70%	0.71%	0.60%	0.63%	0.65%
4	YoY change in Delivery Rate (%)	Current Year - Prior Year; Line 3	0.00%	0.02%	0.02%	0.00%	0.03%	0.02%	0.00%	0.03%	0.02%

Line	Particulars	Reference	2069	2070	2071	2072	2073	2074	2080	2081	2082
5	46710 Measuring & Regulating - Stations ($000s)	BCUC IR1 12.2	-	-	-	13,112	15,141	-	-	-	-
6	46720 Telemetry - Stations ($000s)	BCUC IR1 12.2	8,237	9,512	-	-	-	-	10,242	11,827	-
7	Delivery Rate Impact (%) when compared to 2022 Approved		0.51%	0.56%	0.59%	0.61%	0.69%	0.74%	0.66%	0.72%	0.76%
8	YoY change in Delivery Rate (%)	Current Year - Prior Year; Line 7	0.00%	0.04%	0.03%	0.02%	0.09%	0.05%	0.00%	0.06%	0.04%

On page 96 of the Application, FEI discusses that the East Kootenay Exchange Station and SN-4 Valve Assembly facilities will require a PRS to meet Project objectives.

12.5 Please explain, with rationale, whether the capital costs and the future replacement costs for the two PRS at the East Kootenay Exchange Station and SN-4 Valve Assembly facilities are included in the Total Project Cost – Excluding Sustainment Capital of $84.588 million or included in the Sustainment Capital cost of $103.062 million.

Response:

The capital costs for the two new PRS at the East Kootenay Exchange Station and SN-4 Valve Assembly facilities are part of the total Project cost of $84.588 million (excluding future sustainment capital) and are therefore included as part of the ITS TIMC Project. Please refer to Section 5.4.4.1 of the Application for the rationale for these two new PRS.

Please refer to the response to BCUC IR1 12.2 for an explanation of and rationale for the future replacement costs that are included in the $103.062 million sustainment capital costs as referenced in the preamble above.

12.6 Please confirm when the two PRS at the East Kootenay Exchange Station and SN-4 Valve Assembly facilities are proposed to be placed into service and when the costs are proposed to enter into rate base.

Response:

As stated in Section 5.5 of the Application, the SN-4 Valve Assembly facilities are part of Phase 1 of the Project while the work for the East Kootenay Exchange Station is part of Phase 2. Based on the estimated Project schedule shown in Table 5-1 of the Application, Phase 1 is estimated to complete in 2025; therefore, the capital costs associated with the SN-4 Valve Assembly facilities will be added to FEI's rate base on January 1, 2026. Phase 2 is estimated to complete in 2026 and the East Kootenay Exchange Station assets will therefore be added to rate base on January 1, 2027.

13.0 Reference: FINANCIAL ANALYSIS

Exhibit B-1, Section 5.10, pp. 113-114

Post Project Work

On pages 113 and 114 of the Application, FEI states:

> Once the pipeline and facility modifications described in the sections above have been completed for each of the pipelines in the ITS, FEI will undertake the following work:
>
> 1. Run EMAT ILI tools in the ITS pipelines as modifications are completed and runs can be undertaken;
> 2. The results of the EMAT ILI tool run will be used to inform integrity digs and repairs, as required; and,
> 3. Segments with poor quality EMAT ILI data may need further investigation into the presence of cracking threats.
>
> To manage the additional work associated with FEI's transmission system integrity management activities described above, FEI may require additional headcount as well as new double block and bleed tools to perform repair work. The extent of post project work required cannot be confirmed until the EMAT ILI tool has been run on each pipeline, integrity digs have been performed, and results interpreted.
>
> FEI will request approval of the incremental increase in O&M or Sustainment Capital either in an upcoming Annual Review, or in the next MRP or Revenue Requirements application (RRA) filing, depending on when the runs are planned. As integrity digs have been approved for flow-through treatment during the term of the MRP, FEI will include estimates of additional integrity dig costs that are associated with the capabilities enabled by the ITS TIMC Project for review by the BCUC in its annual reviews as applicable.

13.1 Please discuss whether any post project work costs (including future EMAT ILI runs) will be included in i) the Sustainment Capital estimate of $103.062 million for the Project or ii) in the "O&M or Sustainment Capital either in an upcoming Annual Review, or in the next MRP or Revenue Requirements application (RRA) filing" discussed on pages 113 and 114 of the Application.

Response:

With regard to the estimated future capital replacement costs for assets related to the station telemetry and measuring & regulating equipment, these costs are included in the $103.062 million referenced in this IR. Please refer to the response to BCUC IR1 12.2 for further discussion on the sustainment capital estimate of $103.062 million. However, as noted in the response to BCUC

IR1 12.2 and consistent with FEI's presentation and treatment in its other CPCN applications (including the CTS TIMC CPCN), these costs are not part of the capital cost estimate for the ITS TIMC Project that is the subject of the approvals sought in this Application. If these costs materialize, FEI will seek BCUC approval for these costs in a future revenue requirement application or CPCN application, depending on the magnitude of the costs.

The costs related to future EMAT ILI runs are not included in the sustainment capital estimate of $103.062 million. This is consistent with the financial analysis completed for the approved CTS TIMC Project.[19] FEI notes that major pipeline inspection costs, including the costs of the ILI runs, are capitalized in accordance with FEI's capitalization policy approved by Order G-141-09.[20]

Under the current MRP, integrity O&M expenditures are approved to be treated as flow-through.[21] As 2024 is the last year of the current MRP, FEI will seek approval of future (2025 and later) integrity-related O&M and sustainment capital resulting from the ITS TIMC Project as part of the rate setting filing for the relevant year(s).

13.2 Please provide an estimate of the costs for each of the post project work tasks described in the Application. As part of the response, please provide an estimate of running the EMAT ILI tools on a per-run basis, on an annual basis for the ITS TIMC system, and the number of runs expected over the 65 year post-project analysis period.

Response:

The cost to run EMAT ILI tools differs for each of the ITS pipelines because of their varying lengths, diameters and configurations. Based on current forecasts, which are consistent with the estimates provided in the response to BCUC IR1 28.2 in the CTS TIMC Project proceeding and referenced in that decision,[22] a single EMAT ILI tool run can range from $1.5 to $2.5 million (inclusive of both FEI's costs and contractor costs). The current forecast frequency of EMAT ILI tool runs is once every seven years. Therefore, assuming a seven-year re-inspection cycle, FEI expects to run an EMAT ILI tool eight to ten times per pipeline over the 65-year post-Project analysis period, for a total of approximately 75 runs across the eight ITS pipelines, or equivalent to an annual average cost of approximately $1.7 million to $2.9 million over the 65-year post-

[19] Page 36 of Decision and Order C-3-22.
[20] Terasen Gas Inc. 2010 and 2011 Revenue Requirements and Delivery Rates Application, Order G-141-09 dated November 26, 2009, Appendix A, p. 15.
[21] MRP Decision and Order G-165-20, p. 74.
[22] Page 36 of Decision and Order C-3-22.

Project period.[23] Actual re-inspection frequencies and scheduling for each pipeline will be determined based on the findings after each tool run.

As discussed in the response to BCUC IR1 13.1, the cost of EMAT ILI runs is not part of the ITS TIMC Project cost. FEI will request approval of the future incremental costs for the EMAT ILI tool runs as part of future rate setting applications; the timing of these requests will depend on the timing of the runs.

13.3 Please provide a brief description of the potential additional headcount, new double block and bleed tools and repair work associated with FEI's transmission system integrity management activities.

13.3.1 As part of the response, please discuss how the costs for the potential additional work described in the preceding IR will be treated.

Response:

With respect to additional headcount, similar to the CTS TIMC Project, and as described in the response to BCUC IR1 28.1 in the CTS TIMC Project proceeding, FEI may require additional support in the following departments for the incremental work associated with post-ITS TIMC Project EMAT ILI tool runs on the eight ITS pipelines:

- **Gas Control:** to provide additional support for in-line inspections using EMAT ILI tools. Gas Control resources plan for and monitor the flowrates and pressure in the system during inspections and are integral to successful tool runs. The narrower operating ranges of EMAT ILI tools when compared to FEI's existing ILI tools may drive additional support over the current baseline;
- **System Integrity:** to analyze the EMAT ILI data, develop discrete projects to mitigate blind spots after the baseline runs, and perform on-going risk assessments using the information provided by the EMAT ILI program; and
- **Operations**: to plan for and run the EMAT ILI tools and respond to findings by performing integrity digs and repairs.

FEI will seek approval of additional resources as a result of the ITS TIMC Project as they are defined and needed in future rate setting applications.

[23] 75 runs / 65 years = Average 1.15 runs per year at $1.5 million to $2.5 million per run.

With respect to the double block and bleed tools[24], they are required to provide safe working zones when the pipeline field crews are isolating the lines when conducting repair work based on the findings from the EMAT ILI runs. As noted in the Application and referenced in the preamble, FEI might require additional double block and bleed tools as a result of running the EMAT ILI tools on the ITS pipelines; however, this would depend on the amount of repair work that is required and FEI will include any incremental costs in its future sustainment capital forecasts.

FEI intends to stage the requests for resources and materials identified above as FEI becomes better informed on the level of effort required during the baseline EMAT ILI tool runs.

With respect to the repair work associated with FEI's transmission system integrity management activities, this is referring to the integrity digs and the resulting repair work on the pipeline at the digs. These costs are part of FEI's integrity O&M, which as discussed above and in the response to BCUC IR1 13.1, are currently approved to be treated as flow-through. Consistent with all integrity digs and repair activities, FEI will request approval for these costs in its rate setting applications, which will be based on the findings from the ILI tool runs and the extent of repair work required.

13.3.2 Notwithstanding that the "extent of post project work required cannot be confirmed until the EMAT ILI tool has been run," please provide an estimate of the costs for the potential additional work described in the preceding IR. If no estimate is available for the ITS TIMC Project, please provide any recent comparable costs for other similar projects, if available.

Response:

FEI is unable to provide a meaningful cost estimate at this time regarding the post run integrity digs, repairs, and poor data quality segments. FEI will not know the state of the pipeline and the extent of repair work needed to the ITS pipelines until the EMAT ILI tools are run through the pipeline, quality data is received, and data is analyzed.

FEI can provide an example of the two pilot projects conducted as part of the development of the CTS TIMC CPCN Application. As shown in the response to BCUC IR1 11.1.1 in the CTS TIMC Project CPCN proceeding, the cost to alter the two pipelines to enable ILI tool runs and run the initial ILI tool was $7.4 million. The breakdown of the $7.4 million is as follows:

[24] The API Specification 6D defines a double block and bleed valve as a "single valve with two seating surfaces that, in the closed position, provides a seal against pressure from both ends of the valve with a means of vending/bleeding the cavity between the seating surfaces."

- $5.6 million for the preparation work to ready the two pipelines for EMAT ILI tools; and
- $1.8 million attributable to the EMAT ILI tool runs on the two CTS pipelines.

Subsequently, FEI has spent a total of $5.3 million on 24 integrity digs between 2020 and 2022 that were driven by the findings of the EMAT ILI tool runs on the two CTS pipelines as part of the pilot.

Therefore, using the cost information from the pilot projects above and excluding the $5.6 million related to pilot preparation work, this example shows that it cost $7.1 million to run the EMAT ILI tools ($1.8 million) and respond to the findings ($5.3 million) for two CTS pipelines. This results in an average cost of $3.55 million per pipeline.

FEI notes that this average of $3.55 million per pipeline is just an illustration of specific costs for the two pipelines included in the pilot project and integrity digs, and should not be used as a future estimate for the ITS pipelines. The costs will be different for each pipeline and will be dependent on the findings from the ILI tool runs, the condition of the pipelines, and the extent of repairs required for each pipeline.

D. ENVIRONMENT AND ARCHAEOLOGY

14.0 Reference: ENVIRONMENT AND ARCHAEOLOGY

Exhibit B-1, Section 7.2.3, p. 131; Section 5.8, p. 106 - 108

Environmental Permitting

On page 131 of the Application, FEI states:

> Based on the results of the EOA, the Project will likely require permitting/authorization under the legislation, regulations and bylaws described in Section 5 of the Application. During the detailed engineering phase of this Project, FEI will undertake further environmental assessments to confirm permitting requirements and will apply for permits as required.
>
> The permits identified at this time are based on the current level of Project engineering and may change during the detailed engineering phase.

On page 106 of the Application FEI states that the project will require environmental permits from a number of different permitting agencies:

> Federal notifications and approvals from DFO will be required to comply with the provisions of the Fisheries Act. In particular, applications for licenses and the request for review regarding work in and around fish-bearing streams will require approximately two months for preparation and approval.
>
> FEI will require permits and approvals from several provincial agencies, including: the BC Oil and Gas Commission (BCOGC), Agricultural Land Commission (ALC), Ministry of Forests, Lands, Natural Resource Operations, and Rural Development (FLNRORD), and Ministry of Transportation and Infrastructure (MOTI).

On pages 106 – 108 of the Application, FEI provides a high-level description of the different permitting agencies and some potential implications to the project.

14.1 Please provide a list of environmental permits FEI has identified as being required.

Response:

At this time, FEI has identified the following environmental permits as being required:

- Licence to Fish for Scientific, Experimental or Education Purposes (Fisheries and Oceans Canada);
- Request for Project Review (Fisheries and Oceans Canada);
- Notification for Changes in and about a Stream (BC Oil and Gas Commission); and
- General Wildlife Permit and Scientific Fish Collection Permit (BC Ministry of Forests).

14.2 Please provide a list of any additional environmental permits FEI anticipates may be required, based on its experience completing similar projects.

14.2.1 Please discuss how cost and schedule impacts of potential additional environmental permits have been accounted for within the cost estimate and schedule as currently proposed.

Response:

FEI anticipates the following permits may be required depending on the outcome of detailed engineering:

- Waste Discharge Authorization (BC Oil and Gas Commission);
- Transportation, Utility, and Recreational Trail Use Approval (Provincial Agricultural Land Commission); and
- Notice of Intent for soil deposition or removal for soils in the Agricultural Land Reserve (Provincial Agricultural Land Commission).

FEI has accounted for the timelines and costs of these potential additional permits in the overall Project schedule and cost estimate.

E. CONSULTATION AND ENGAGEMENT

15.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-1, Table 8-2, p. 145; Table 8-3, p. 146-148; Section 8.3.6, p. 149

Capacity Funding

On page 145 of the Application, FEI identifies 35 First Nations that may be impacted by the project and require consultation. On pages 146 – 148 of the Application, FEI identifies 8 Indigenous groups that responded to their initial efforts to inform First Nations about the Project.

On page 149 of the Application, FEI states:

> As the Project progresses, FEI will continue to follow up and address concerns that have been identified as part of our early engagement efforts. FEI will support Indigenous engagement activities through capacity funding if requested and will reach out to Indigenous groups during the procurement process to identify employment and contract opportunities.

15.1 Please describe what additional measures, if any, will be made to specifically engage those impacted First Nations that did not respond to FEI's initial efforts to inform them about the project.

Response:

FEI will continue to communicate with all identified Indigenous groups potentially impacted by the Project throughout its lifecycle, including any that did not respond to FEI's initial outreach. This will include sharing the results of environmental and archaeological reports and engagement on site-specific impacts through the BCOGC permitting process. Further, FEI intends to engage Indigenous groups on employment and contracting opportunities on the Project.

15.2 Please provide a description of the capacity funding that will be made available to impacted First Nations.

15.2.1 Please discuss how impacted First Nations will be made aware that these funds are available to them.

15.2.2 Please elaborate on how these funds are to be accessed, and how FEI determines the amount of funds to be provided

Response:

FEI's typical practice is to offer capacity funding to Indigenous groups throughout the project lifecycle to facilitate Indigenous engagement with respect to assessing the project's potential impacts on their Indigenous rights and interests. This funding is generally provided on a case-by-case basis depending on the level of engagement required in light of the potential impact to the Indigenous groups and their desired level of engagement.

FEI has working relationships with many Indigenous groups who are aware that FEI provides capacity funding to support engagement. Furthermore, FEI generally informs potentially impacted Indigenous groups of the availability of capacity funding as part of project engagement.

F. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES AND LTRP

16.0 Reference: PROVINCIAL GOVERNMENT ENERGY OBJECTIVES and LTRP
Exhibit B-1, Section 9.2, p. 150
Economic Benefits

On page 150 of the Application, FEI states:

> The Project will support the British Columbia energy objective in section 2(k) of the CEA "to encourage economic development and the creation and retention of jobs." The Project will support this objective by creating jobs and contributing to the local economy. The Project will create jobs in BC through FEI's contractors, and result in the procurement of goods and services from locally-owned and operated vendors and subcontractors. FEI also anticipates an increase in the use of local services, such as dining, lodging accommodations and other services, during construction will benefit the economy.
>
> FEI is committed to working with Indigenous groups, community leaders and local organizations, developing the local workforce, supporting local businesses, and connecting them to Project opportunities. For example, to promote Indigenous and other local participation in the Project, FEI will host business-to-business and worker-to-business networking events. These events would facilitate introductions between Indigenous and other local business owners, members of the local workforce, and connect them to contract and employment opportunities.

16.1 Please describe how FEI defines "locally-owned and operated vendors and subcontractors".

Response:

FEI's reference to "locally-owned and operated vendors and subcontractors" includes businesses located in, or close to, the municipality and/or the regional district in which the Project is to be located and undertaken.

16.2 Please provide a quantitative assessment of the likely economic impact that this Project is anticipated to have on the region, including the procurement of goods and services from local venders.

Response:

FEI works closely with local and Indigenous vendors throughout the project lifecycle to identify and create procurement opportunities. In Section 5.9.1.1 of the Application, FEI notes that it anticipates the Construction Cost Estimate (Contractor & FEI) to be $50.2 million, which will create significant economic opportunity for the region.

It is premature for FEI to be able to provide a quantitative assessment of local and Indigenous economic impact on the Project as this requires further engagement with Indigenous groups, community leaders, and local vendors to identify and confirm specific economic opportunities. This may include direct procurement of goods and services, or subcontract opportunities through the eventual general contractor(s), selected at a future date.

Ultimately, FEI is committed to working with community leaders and local contractors to facilitate Indigenous and local participation on the Project, as discussed in Section 9.2 of the Application. FEI will track local and Indigenous participation throughout the design-execution phase of the Project to assess total economic impact through quarterly socio-economic reporting. For example, on the IGU project, FEI spent approximately $128 million between January 1 and September 30, 2022. Of that, approximately $28.6 million (22 percent) was sourced to Indigenous owned and affiliated vendors; and $82 million (64 percent) was sourced to BC based businesses.

16.3 Please provide FEI's assessment of the level of interest among local Indigenous workers and businesses to participate in the proposed networking events.

Response:

FEI regularly engages with local and Indigenous vendors across the Province to discuss procurement opportunities on both major projects and sustaining capital works. Through this engagement, participants have expressed their interest in participating in procurement opportunities, including through these networking events.

Recently, FEI held a business-to-business session in Surrey, BC and received positive feedback on the event and an interest in project and sustaining capital opportunities from the Indigenous groups in attendance. As such, in the future, FEI intends to hold business-to-business workshops, including in the interior of BC, which will include participation from representatives of the ITS TIMC Project.

16.3.1 Please discuss whether FEI has established any metrics against which it will assess the success of its efforts to connect Indigenous groups, community leaders and local organization.

Response:

FEI measures the effectiveness of its efforts to connect with Indigenous groups, community leaders and local organizations in various ways. In addition to receiving a response and engagement with those that FEI is seeking to connect with, FEI undertakes socio-economic reporting on its major projects to track local and Indigenous procurement. This reporting helps provide feedback and context towards FEI's efforts to secure local and Indigenous participation in its projects. Finally, FEI is developing a metric to track and monitor FEI's engagement with key communities on an annual basis.

17.0 Reference: PROVINCIAL GOVERNMENT ENERGY OBJECTIVES and LTRP

Exhibit B-1, Section 3.2.3.3, p. 25, Section 3.4.7, p. 46; Section 9.3.1, p. 151; BCUC Decision and Order C-3-22, Section 10.1, p. 60

BC Climate Targets and Hydrogen Blending

On page 151 of the Application, FEI states:

> As discussed in section 3.3.4 of the 2022 LTGRP, FEI envisions hydrogen playing a critical role in decarbonizing BC's industrial sector and meeting BC's climate targets. The information gathered through EMAT ILI runs will factor into FEI's analysis regarding the concentration of hydrogen each pipeline can safely accommodate in the future. In turn, this will allow FEI to determine a safe and cost-effective plan for transitioning to increased hydrogen distribution, further enabling FEI to meet its Clean Growth Pathway.

On page 25 of the Application, FEI states:

> At the time of this Application, EMAT tools suitable for FEI's natural gas pipelines of NPS 10 and larger have been sufficiently commercialized.

On page 46 of the Application, FEI states:

> FEI currently operates approximately 100 transmission pipelines with diameters NPS 8 or smaller, which operate at a hoop stress level greater than 30 percent SMYS. Since EMAT tools are currently only commercialized and available for pipelines of diameter NPS 10 and larger, FEI did not include transmission pipelines with diameters smaller than NPS 10 in the scope of its TIMC projects. FEI will continue to inspect these pipelines for cracking during opportunity digs and, if significant cracking is discovered, it will develop a line specific mitigation plan.

Page 60 of the BCUC Decision and Order C-3-22 states:

> The provincial government issued its CleanBC Roadmap to 2030 (CleanBC Roadmap) in October 2021, which among other initiatives, proposes to limit GHG [green house gas] emissions from the use of natural gas in 2030 to approximately 47 percent less than 2007 levels. Due to the timing of the CleanBC Roadmap release date, FEI was not aware of these energy objectives at the time the Application was filed. However, FEI does submit that the CleanBC Roadmap is not relevant as the CTS TIMC Project is driven by pipeline safety risks posed by cracking threats.
>
> Given that the CleanBC Roadmap is now in place, the Panel requests that FEI include information in its forthcoming ITS TIMC CPCN Application, which demonstrates how, if at all, that project aligns with FEI's own decarbonization

goals, as well as the provincial energy objectives outlined in the CleanBC Roadmap.

17.1 Please provide a more detailed description of how this Project will help to decarbonize BC's industrial sector and meet BC's climate targets.

17.1.1 Please clarify whether any GHG reductions that may result from this Project rely solely upon a future scenario in which FEI distributes a blend of hydrogen and natural gas to its ITS customers.

Response:

While the need for the ITS TIMC Project is driven by safety risks posed by credible cracking threats on ITS pipelines, the Project will support and indirectly help to meet FEI's decarbonization goals and to decarbonize BC's industrial sector to meet BC's climate targets.

The ITS TIMC Project enables running EMAT ILI tools which FEI has identified as the only feasible and cost-effective alternative to detect planar imperfections, such as cracking. In addition to mitigating these credible cracking threats, the information gathered through EMAT ILI runs will factor into FEI's analysis regarding the concentration of hydrogen each pipeline can safely accommodate in the future. This in turn will allow FEI to determine a safe and cost-effective plan for transitioning to increased hydrogen distribution, further enabling FEI to meet its decarbonization goals and BC's climate targets.

17.2 Based on FEI's current plans to integrate hydrogen into its system, please discuss whether FEI anticipates blending hydrogen into only ITS transmission pipelines, only ITS distribution pipelines or into both ITS transmission and distribution pipelines.

Response:

FEI envisions integrating hydrogen into its conventional natural gas system (including ITS pipelines) with goals over the near, medium and long term as discussed below and outlined in FEI's 2022 LTGRP.[25]

Over the next five years, FEI will be considering a number of approaches to locally displace conventional natural gas in the gas system and opportunities to distribute hydrogen directly to gas customers. To support this goal, FEI is enabled under the GGRR to acquire hydrogen to meet near-term objectives including:

[25] FEI 2022 LTGRP – Section 3.3.3.

- Blending hydrogen in the gas distribution system to displace conventional natural gas (similar to RNG) including either hydrogen produced by FEI or through a third party; and
- Purchasing hydrogen that could be distributed through dedicated infrastructure (new or repurposed) to gas customers to displace conventional natural gas usage.

In the medium term (projected to be by 2030), blends of hydrogen will expand across the low-pressure gas distribution system, with the potential for segments within the system to expand to include hydrogen hubs which can distribute 100 percent hydrogen.

Over the longer term (between 2030 and 2050), and as demand for hydrogen grows, the existing gas system's high pressure transmission pipeline corridors will be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and RNG in a progressively decarbonized gas system.

17.2.1 Please discuss how FEI will analyze the concentration of hydrogen which can safely be accommodated within pipelines of NPS 8 diameter and smaller.

Response:

As discussed in the response to RCIA IR1 17.1 and the response to CTS TIMC BCUC IR1 1.1, FEI will undertake an Engineering Critical Assessment (ECA) of each pipeline segment to determine the fitness for hydrogen service of each pipeline asset. This analysis will examine the compatibility of the pipeline materials of construction with hydrogen to define the safe hydrogen concentration limit of each of these assets. Where feasible, FEI intends to use EMAT ILI data to improve characterization of line pipe segments; however, in the absence of EMAT ILI information, FEI will make informed engineering assessments to determine the concentration of hydrogen that can be safely accommodated within pipelines of NPS 8 diameter and smaller.

17.2.2 Please discuss how this Project will benefit FEI's analysis regarding the safe concentration of hydrogen in all of its pipeline assets in the ITS.

Response:

As explained below, the data collected from in-line inspection tools (MFL, C-MFL and EMAT) is a key input for determining the safe concentration of hydrogen in pipeline assets, including those in the ITS that will be inspected following completion of the Project.

The compatibility of steel pipelines with hydrogen and, in particular, the concentration of hydrogen that can be accommodated as part of a fuel blend depends on the characteristics of each pipeline. These characteristics include the pipe material (i.e., steel grade and wall thickness), the pipeline system operating pressure and loading parameters, gas composition, etc. Even pipe that was not designed from the outset to be hydrogen-ready may still be determined to be capable of transporting hydrogen in higher concentrations.

In order to establish the maximum concentration of hydrogen that a given pipeline can accommodate, FEI must first undertake an engineering assessment which considers a range of factors in assessing the interaction of hydrogen with pipeline steels, including:

- What data is necessary for FEI to determine whether a specific pipeline material is compatible with the planned hydrogen service;
- What information is currently known or can be readily obtained by FEI;
- If certain information is not known, what FEI can be done to learn it; and
- Where data cannot be obtained, or is not reliable, what approach or conservative assumptions FEI can adopt in order to proceed.

17.3 Please describe how the project aligns with provincial energy objectives outlined in the CleanBC Roadmap.

Response:

Measures in the CleanBC Roadmap enable transitioning the Province's energy resources towards renewable and low-carbon energy, such as Renewable Natural Gas and hydrogen, and support the implementation of the BC Hydrogen Strategy.[26] At a high level, FEI's existing pipeline infrastructure will play an important role in reducing greenhouse gases by transitioning to delivering an increasing share of this type of energy over time in order to meet provincial energy objectives outlined in the CleanBC Roadmap.

As explained in Section 9.3.1 of the Application, the ITS TIMC Project will enable FEI to gather information through EMAT ILI inspections that could be used to analyze the potential for the ITS pipelines to safely transport hydrogen in the future, reflecting the importance of leveraging existing pipeline infrastructure. This will allow FEI to plan effectively for a successful transition to hydrogen distribution, further enabling FEI to meet its Clean Growth Pathway.

[26] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf.

Please also refer to the response to BCUC IR1 17.1 which describes how the ITS TIMC Project will support the potential future delivery of hydrogen in the ITS, thus displacing higher-carbon intensity fuels in homes, businesses and industry in BC.

Attachment 2.1.1

Compliance Assurance Report for Facilities Integrity Management Program

Compression and LNG

FortisBC Energy Inc.

Final

December 15, 2021

Permit Holder and Audit Information

Permit Holder Name	**FortisBC Energy Inc.**
Audit date	October 22, 2021
Primary Contact	Bryan Balmer
Permit Holder Representatives	
Bryan Balmer – Manager, System Integrity Programs	Doyle Sam – Executive Vice President, Operations & Engineering
Aram Khalil-Pour – Director, Engineering Services	Patrick Sullivan – Senior Engineer, Compression Assets
Ferenc Pataki – Director, Transmission	Curtis Klashinsky – Manager, Assets and Compliance
Parisa Valipour – Senior Engineer, Integrity Management Systems	Omar Maan – Integrity Management Systems Consultant
Brent Kavelaars – Manager, Engineering (Gas)	Marko Aaltomaa – Director, Generation and Compression
Katrina Craig – Director, Internal Audit and Risk	Ian Finke – Director, LNG operations
Michael Banner – Technical Process Safety Risk Specialist	Brent Masuch – Operations Manager, Coastal Compression
Wasim Yasin – Process Safety Manager, LNG	Allen Yasemi – Integrity Management Systems Consultant
Ian Turnbull – Damage Prevention & Emergency Services Manager	Chris Kormendy – Manager, LNG Operations
BCOGC Audit team	
Bushra Waheed	Senior Integrity Auditor
Shani Steinhubl	Senior Integrity Engineer
Kevin Parsonage	Supervisor, Integrity Programs
Alex Warthe	Facility Integrity Engineer
Report Preparation, Review, and Approval	
Prepared by	Alex Warthe, Shani Steinhubl, and Bushra Waheed
Reviewed by	Kevin Parsonage

1. Compliance Assurance Process – Facility Integrity Management Program

The BC Oil and Gas Commission (Commission) expects the permit holders under its jurisdiction to anticipate, prevent, mitigate, and manage the risks that can adversely affect safety and the environment. Facility permit holders are required to have an Integrity Management Program, for managing asset integrity throughout the lifecycle of their facility assets.

In February 2017, the Commission finalized its new compliance assurance process for facility integrity management programs (IMPF). The Commission's scope and expectations are detailed in a guideline document, called Compliance Assurance Protocol - Integrity management Program for Facilities, available on the Commission's website.

The regulatory requirements for IMPFs are based on the Oil and Gas Activities Act; Drilling & Production Regulation (DPR Section 78.1); Liquefied Natural Gas Facility Regulation, and CSA Z662 (for more details, refer to the Introduction of the Commission's Compliance Assurance Protocol for Integrity Management Programs for Facilities).

Permit holders are notified of their selection to participate in the Commission's compliance assurance process for IMPFs in the beginning of the audit year. Due to the travel restrictions and potential safety concerns regarding the COVID-19 pandemic, the Commission is now conducting remote audits through a combination of documentation submissions and online meetings. Permit holders are required to submit the completed workbooks and associated records and documentations within a specified timeframe. The Commission reviews IMP-related documentation and manuals submitted by the permit holders and also compliance and incident history of the permit holders as available in the Commission's internal database. Online audit meetings are carried out as needed and audit reports are issued.

2. Audit Scope and Summary

For FortisBC Energy Inc. (FEI) IMPF audit, the Commission focused on 18 components outlined in the IMPF protocol. The audit entailed confirmation of the scope of the compliance assurance process, a systematic review of workbooks, process records and documents and an online meeting to verify compliance against IMPF components identified in the Compliance Assurance Protocol for both **Compression and LNG** assets owned and operated by FEI.

Non-compliance findings and opportunities for improvement (OFIs) identified during the audit are listed in Table 1. All non-compliances must be addressed within a Corrective Action Plan (CAP) developed by FortisBC Energy Inc. (FEI) and submitted to the Commission within 30 days after receiving the final report. Additional details regarding the Corrective Action Plan submission are provided in Section 4 of this report.

Table 1: List of Non-compliance findings and Opportunities for Improvement (OFIs)

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
1.1 General IMPF	*Requirement/Expectation: The General IMP for facilities (IMPF) subcomponent requires that permit holders document, establish and maintain the IMPF, and ensure the effectiveness of the IMPF. The permit holders shall clearly identify the facilities/equipment, and the processes managed under the IMPF.* No adverse findings.	*NA*
1.2 Policy and Leadership Commitment	*Requirement/Expectation: The Policy and Leadership Commitment subcomponent requires that a permit holder's senior leadership articulate policy and leadership commitment to its IMPF. The permit holder shall establish and maintain leadership commitment to its integrity management program for facilities, overall goals and objectives, providing resources, fostering risk management processes, and implementing and continually improving the integrity management program, through a positive safety culture.* No adverse findings.	*NA*

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
1.3 Goals and Objectives	*Requirement/Expectation: The Goals and Objectives subcomponent requires that a permit holder establish goals and objectives for its IMPF. The objectives shall be consistent with the overall safety policies and objectives (corporate direction). The objectives and targets shall be measurable and must link to the high-level performance measures (key performance indicators), which shall be reviewed, evaluated, and trended.* No adverse findings.	*NA*
1.4 Planning	*Requirement/Expectation: The Planning subcomponent requires that permit holder's management directs or controls the pipelines and define processes, plans, provide resources, and identify and ensure conformance to regulatory and legal requirements, standards and codes.* No adverse findings.	*NA*

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
2.0 Risk Assessment and Management 2.1 Process Knowledge and Information 2.2.1 Hazard Identification: Facility Projects 2.2.2 Process Operations 2.3 Risk Assessment 2.4 Risk Tolerance 2.5 Risk Reduction and Management 2.6 Risk Assessment Update and Review 2.7 Risk Management Review	*Requirement/Expectation: The Risk Assessment and Management component requires the permit holder to document a process for identifying hazard and evaluating and managing risk to ensure safety of their employees, the public and the environment.* **Finding 2.1: Facility Risk Assessment – Risk Registry** **LNG** In Section 4 of FEI's Integrity Management Program for LNG Plants (CRL 2043) there is a requirement to maintain an up-to-date risk registry that is reviewed annually. The risk registry is a tool used to track identified risks and manage risk mitigation activities. Currently FEI does not have a risk registry developed for its LNG plants. Risks are documented and managed separately through each of the various processes to manage risks (MOC, PHA, incidents, etc.). The Commission requires FEI to complete the development of a risk registry for its LNG plants and maintain this risk registry to reduce the gaps left by process centered PHAs and ensure that FEI's LNG facilities have a holistic approach for its risk assessment. Implementing a risk registry will demonstrate compliance to the risk assessment requirements outlined in the Commission's IMPF protocol. Using a risk registry to manage risks within a single tool will also benefit FEI's process for tracking and prioritizing risk mitigation activities.	*Medium*
3.0 Organization Responsibilities	*Requirement/Expectation: The Organizational Structure, Roles and Responsibilities component requires that a permit holder include a suitable organizational structure, with well-defined responsibilities and authorities to establish and maintain an effective IMPF. The integrity management program shall involve personnel within a facility's maintenance, operations, and engineering departments.* No adverse findings.	*NA*

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
4.0 Communication Process	*Requirement/Expectation: The Communication Process component requires that a permit holder establish and implement an effective process for internal and external communication to coordinate information essential to the IMPF.* No adverse findings.	*NA*
5.0 Training and Competency	*Requirement/Expectation: The Competency and Training component requires that a permit holder assess and document the training and competency requirements for its employees to ensure appropriate knowledge and skills for performing the elements of the IMPF for which they are responsible.* No adverse findings.	*NA*
6.0 Document and Record Management	*Requirement/Expectation: The Document and Record Management component requires that a permit holder establish, implement and maintain a process for managing documents and records needed for the effective implementation of IMPF activities during different stages of the facility life cycle, e.g., design, material selection, purchasing, construction, operation, maintenance, and decommissioning.* No adverse findings.	*NA*

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
7.0 Managing Change	*Requirement/Expectation: The Managing Change component requires that a permit holder develop and implement a systematic process for identifying, evaluating, controlling and documenting any change to facility design, specification, operations, standard, organization or activities and legal requirements to ensure that no unforeseen new hazards are introduced and that the risk of existing hazards to employees, public, or the environment is not unknowingly increased.* **OFI 5.0.1 Integration of new MOC process** **LNG** Historically, the Tilbury and Mt. Hayes LNG plants have managed their own management of change (MOC) processes. These existing MOC processes are currently still in use, however, FEI is transitioning the LNG facilities to its recently developed IMP MOC process (CRL 1173). The pipeline and compressor station IMPs are already in alignment with the new FEI MOC process. The Commissions recommends FEI on expediting the transition of its MOC process for LNG plants to improve consistency of its MOC programs across all assets. Using a common MOC process across all assets will allow FEI to ensure the MOC requirements are met across all three IMPs. Additionally, using a common process will aid continual improvement for MOC management as lessons learned can be applied across FEI's operations.	*NA*
8.0 Operational Control	*Requirement/Expectation: The Operational Controls component requires that permit holders establish and maintain procedures for the safe operation of each facility and address the initial start-up (new or modified facilities), normal operation, temporary operation, emergency operation, including shutdowns, normal shutdown, start-up and restoration following maintenance or outage, identifying operating limits, alarm management and control room operations.* No adverse findings.	*NA*

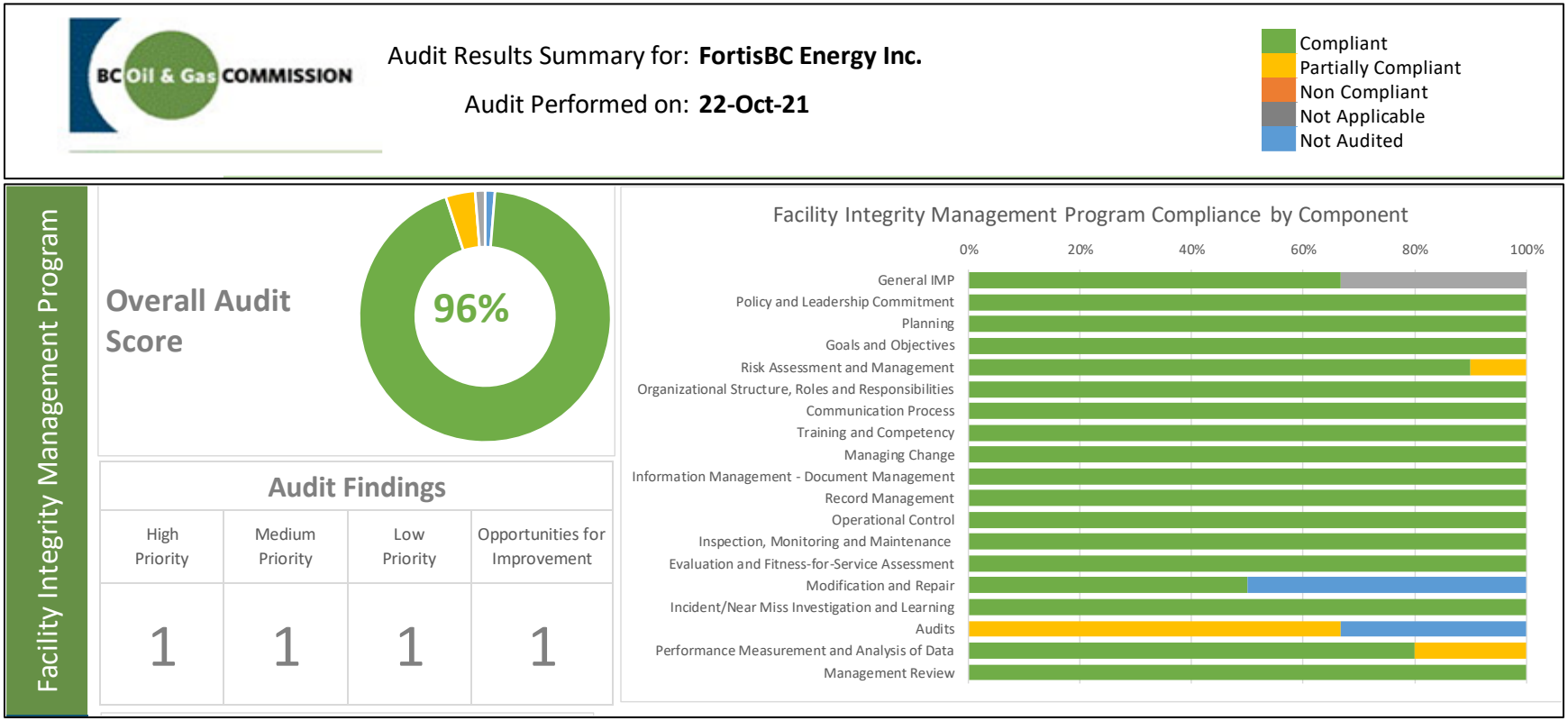
IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
9.0 Inspection, Maintenance and Monitoring (IMM)	*Requirement/Expectation: The Inspection, Monitoring and Maintenance component requires that permit holders document and maintain inspection, monitoring, and maintenance (IMM) programs that are appropriate for its facilities and are in accordance with the risk assessment and management process.* No adverse findings.	*NA*
10.0 Evaluation and Fitness-for-Service Assessment	*Requirement/Expectation: The Evaluation and Fitness-for-Service Assessment component requires that a permit holder conduct inspections and investigations as appropriate, or undertake an Engineering Assessment (EA), such as Fitness-for-Service (FFS) Assessment, when anomalies are identified to evaluate severity of these anomalies.* No adverse findings.	*NA*
11.0 Modification and Repair	*Requirement/Expectation: The Modification and Repair component requires that if permit holder identifies situations for the facility where modification or repair are required, the permit holder shall identify and document relevant corrective actions that are acceptable and appropriate for its facilities considering the service conditions.* No adverse findings.	*NA*
12.0 Incident / Near-miss Investigation and Learning	*Requirement/Expectation: The Incident / Near-miss Investigation and Learning component requires that a permit holder document and implement its process to report and investigate any hazards, potential hazards, incidents or near misses affecting or having the potential to affect the integrity of their facilities.* No adverse findings.	*NA*

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
13.0 Performance Measurement and Analysis of Data	*Requirement/Expectation: The Performance Measurement and Analysis of Data component requires that a permit holder establish and maintain a documented process to identify metrics or key performance indicators (KPIs) to measure the effectiveness of its risk management and the effectiveness and adequacy of its IMPF.* **Finding 13.01: KPI Effectiveness** **Compression and LNG** Within FEI's pre-audit submission for compressor stations and LNG facilities, example KPIs were provided. The provided KPIs indicated that many maintenance activities for both compressor stations and LNG facilities were not completed as scheduled and the resulting KPIs were far below FEI's targeted completion rate. During the audit FEI communicated that additional efforts and resources have been allocated to manage maintenance activities, however the KPIs are not accurately reflecting the performance of FEI's maintenance programs because of the way they are setup and published. FEI also indicated that a new set of KPIs is in development with the recently implemented Facility IMPs. FEI must complete their plans to develop updated KPIs for their recently implemented facility integrity management programs (both compressor stations and LNG plants). Once the updated KPIs are established, FEI must demonstrate that their Facility IMPs are meeting the defined performance targets. Effective and accurate KPIs are necessary to monitor and evaluate the performance of IMPs. Monitoring KPIs and taking corrective actions when necessary are key to integrity management.	*Medium*

IMPF Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
14.0 Internal Audit	*Requirement/Expectation: The Internal Audit component requires that a permit holder develop and implement a process for auditing of its IMPF. A permit holder's process must define the responsibilities, scope, objectives, frequency, and schedule for internal audits. The process for completing corrective and preventive actions for non-conformances identified through internal audits shall be outlined. The process must also ensure auditor competency and independence.* **Finding 14.0.1: Internal Audit Implementation** **Compression and LNG** During the audit, FEI confirmed that the internal audit program for their facility IMPs (consisting of CRL 2043 for LNG plants and CRL 2044 for compressor stations) is not currently implemented since these IMPs were recently introduced. FEI intends to utilize the same internal audit program currently in place for its pipeline IMP but has not yet established a timeline for the implementation of it for compressor stations and LNG plants. FEI must develop a schedule to implement internal audit for both of its facility integrity management programs; CRL 2043 for LNG plants and CRL 2044 for compressor stations. The Commission recognizes that FEI is currently working on plans to implement internal audit for its facility integrity management programs and as a result this has been classified as a low risk finding. Internal audit is a key tool to verify that an integrity management program is being utilized correctly. Ensuring that the internal audit program is implemented in a timely manner will aid FEI in identifying and correcting issues with their Facility IMPs.	*Low*
15.0 Management Review	*Requirement/Expectation: The Management Review component requires that a permit holder review its IMPF to determine the extent to which the performance goals and objectives have been met to assess program effectiveness.* No adverse findings.	*NA*

Audit Performance Evaluation

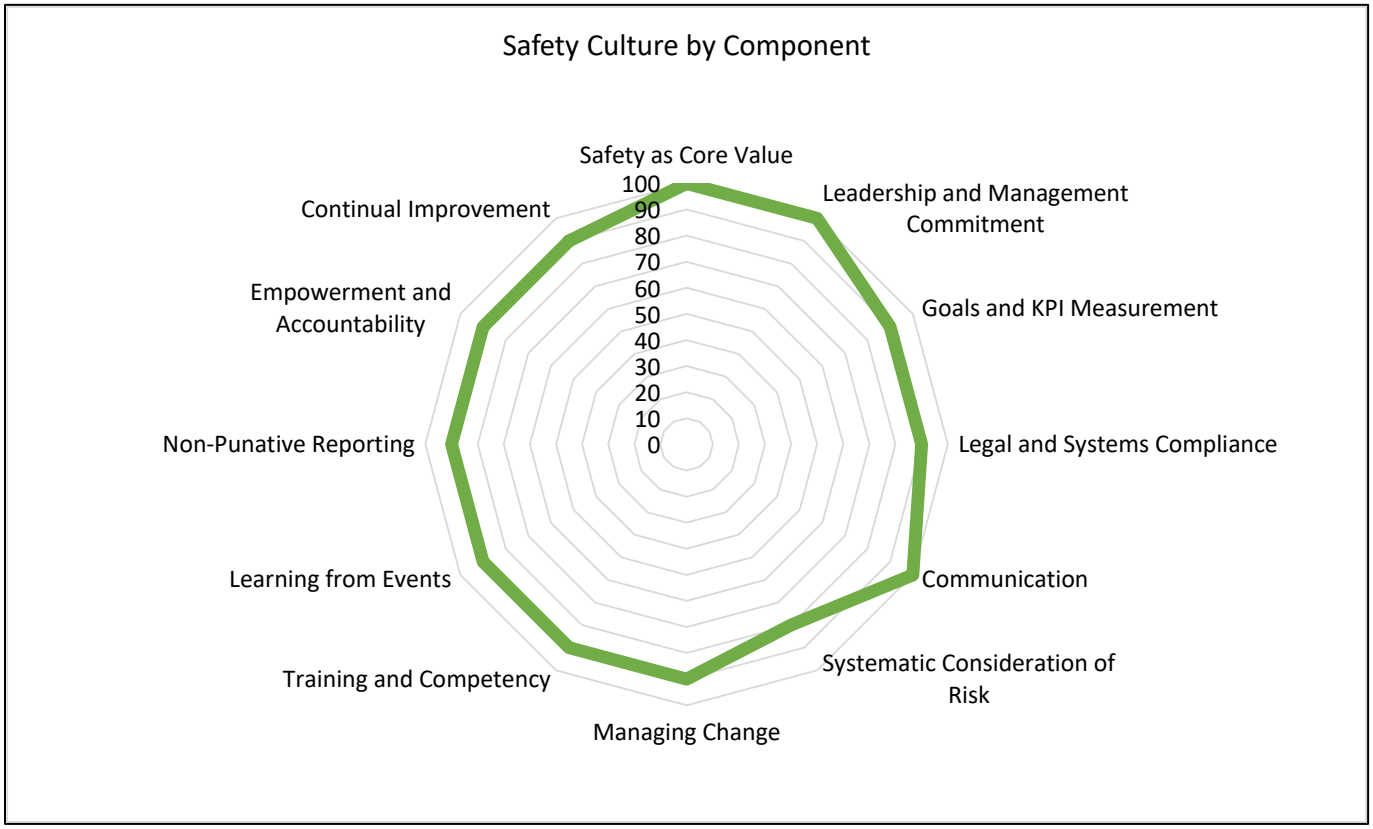
FEI's audit findings are analyzed as compliance rate and risk ranked based on process, execution, scope, documentation, records, and administration. FEI's audit performance is graphically represented below:



3.1 Safety Culture

(Same for IMPP and IMPF)

Safety culture and the implementation of a management system such as integrity management are directly related. Canadian standard, CSA Z662-19 (Annex A- A.1) outlines that awareness and understanding of human factors, organizational factors, organizational culture, and safety culture enable better anticipation and management of system hazards and risks to prevent system failures. The Safety Culture (SC) assessment used by the Commission is based on the IMPP and IMPF audits. The Commission's SC assessment is interpreted through the ten-point scale. For 12 SC indicators, values are assigned as 80-100 for most positive (strong), 50-70 for moderate responses, and 10-40 to represent the least positive indicators (weak). The radar / spider plot below presents the visualization of the overall findings of SC indicators and highlight where more action plans are required for improvement and should be given priority.



3. Corrective Action Submission and Review Process

FEI must address non-compliance findings through the development and implementation of Corrective Action Plans (CAP) for each individual finding. A CAP must outline specific actions required for developing and implementing any changes needed to programs, processes, procedures, or instructions along with responsibilities and timelines for implementation to address each finding. The CAPs must be submitted to the Commission, via email to integrityengineering@bcogc.ca, within 30 days of receipt of the final report.

Once the Commission approves a permit holder's CAPs, the permit holder must continue to implement corrective actions and submit progress update and evidence of completion at a frequency mandated by the Commission.

The Commission's oversight process for CAPs is based on risk. CAPs are monitored and assessed until they have been fully resolved. Confirmation of the CAPs resolution may include requesting email submissions, arranging in-person, over the phone/online review meetings, or further compliance verification assessments to ensure that corrective actions defined within the CAP have been implemented.

The Commission would like to thank FEI for its continued participation and cooperation in the Commission's compliance assurance process.

Compliance Assurance Report for Pipelines Integrity Management Program

FortisBC Energy Inc.

Final

December 15, 2021

Permit Holder and Audit Information

Permit Holder Name	**FortisBC Energy Inc.**
Audit date	October 22, 2021
Primary Contact	Bryan Balmer
Permit Holder Representatives	
Bryan Balmer – Manager, System Integrity Programs	Doyle Sam – Executive Vice President, Operations & Engineering
Aram Khalil-Pour – Director, Engineering Services	Patrick Sullivan – Senior Engineer, Compression Assets
Ferenc Pataki – Director, Transmission	Curtis Klashinsky – Manager, Assets and Compliance
Parisa Valipour – Senior Engineer, Integrity Management Systems	Omar Maan – Integrity Management Systems Consultant
Brent Kavelaars – Manager, Engineering (Gas)	Marko Aaltomaa – Director, Generation and Compression
Katrina Craig – Director, Internal Audit and Risk	Ian Finke – Director, LNG operations
Michael Banner – Technical Process Safety Risk Specialist	Brent Masuch – Operations Manager, Coastal Compression
Wasim Yasin – Process Safety Manager, LNG	Allen Yasemi – Integrity Management Systems Consultant
Ian Turnbull – Damage Prevention & Emergency Services Manager	Chris Kormendy – Manager, LNG Operations
BCOGC Audit team	
Bushra Waheed	Senior Integrity Auditor
Shani Steinhubl	Senior Integrity Engineer
Alex Warthe	Facility Integrity Engineer
Kevin Parsonage	Supervisor, Integrity Programs
Report Preparation, Review, and Approval	
Prepared by	Alex Warthe, Shani Steinhubl, and Bushra Waheed
Reviewed by	Kevin Parsonage

1. Compliance Assurance Process – Pipeline Integrity Management Program

The BC Oil and Gas Commission (Commission), under Section 7 of the Pipeline Regulation (PR), requires that every permit holder planning, designing, constructing, operating, maintaining, or abandoning pipeline infrastructure within the province of British Columbia must have fully developed and implemented pipeline integrity management programs (IMPP). To promote safe, reliable, and environmentally responsible pipeline infrastructure, the Commission has been undertaking compliance monitoring of permit holders' IMPP through its compliance assurance process since 2011.

The compliance assurance process is based on the most current version of the CSA Z662 standard, the guidelines outlined in CSA Z662 Annex N, the Oil and Gas Activities Act (OGAA), and subordinate regulations. According to CSA Z662 Clause 3, an IMP forms part of a comprehensive safety and loss management system and shall apply to the entire lifecycle of a pipeline system. The Commission requires permit holders to comply with the IMPP requirements defined within its Compliance Assurance Protocol available online at http://www.bcogc.ca/node/5950/download. The objective of the Commission's compliance assurance process is to verify adequate development, implementation, and effectiveness of a permit holder's IMPP. The process integrates the management system approach to evaluate if defined goals, objectives, and targets facilitate continual improvement and overall effectiveness of the IMP. Permit holders must demonstrate that they are proactively identifying and managing all hazards and risks associated with their pipelines.

Permit holders are notified of their selection to participate in the Commission's compliance assurance process for IMPPs in the beginning of the audit year. Due to the travel restrictions and potential safety concerns regarding the COVID-19 pandemic, the Commission is now conducting remote audits through a combination of documentation submissions and online meetings. Permit holders are required to submit the completed workbooks and associated records and documentations within a specified timeframe. The Commission reviews IMP-related documentation and manuals submitted by the permit holders and also compliance and incident history of the permit holders as available in the Commission's internal database. Online audit meetings are carried out as needed and audit reports are issued.

2. Audit Scope and Summary

For FortisBC Energy Inc. (FEI) IMPP audit, the Commission focused on 18 IMPP components outlined in the IMPP protocol along with the damage prevention requirements (DPP). The audit entailed confirmation of the scope of the compliance assurance process, systematic review of workbooks, process records and documents and an online meeting to verify compliance against IMPP components identified in the Compliance Assurance Protocol and DPP requirements in accordance with Pipeline Regulation (Section 7(2)). Findings of either compliance or non-compliance were debriefed at the end of the online meeting to the auditee.

Non-compliance findings and opportunities for improvement (OFIs) identified during the audit are listed in Table 1. All non-compliances must be addressed within a Corrective Action Plan (CAP) developed by FEI and submitted to the Commission within 30 days after receiving the final report. Additional details regarding the Corrective Action Plan submission are provided in Section 4 of this report.

Table 1: List of Non-compliance findings and opportunities for improvement

IMPP Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
1.1 General IMPP	*Requirement/Expectation: The General IMPP subcomponent requires that a permit holder develop and implement an integrity management program (IMP) that addresses the entire life cycle of the pipeline system, that is, planning, design, construction, operation, maintenance, and abandonment.* No adverse findings.	*NA*
1.2 Policy and Leadership Commitment	*Requirement/Expectation: The Policy and Leadership Commitment subcomponent requires that permit holders establish, implement, and maintain a documented policy to demonstrate senior leadership commitment to the IMP program and its continual improvement.* No adverse findings.	*NA*

IMPP Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
1.3 Goals and Objectives	*Requirement/Expectation: The Goals, Objectives, and Targets subcomponent requires that a permit holder set goals to reflect the direction and desired outcomes of the policy as well as defining objectives, targets and measurable performance indicators for evaluating the performance of its IMP.* No adverse findings.	*NA*
1.4 Planning	*Requirement/Expectation: The Planning subcomponent requires that the permit holder's management directs or controls the pipelines and defines processes and plans, provide resources, and identify and ensure conformance to regulatory and legal requirements, standards and codes.* No adverse findings.	*NA*
1.5 Risk Assessment	*Requirement/Expectation: The Risk Assessment subcomponent requires that a permit holder apply a risk assessment process that identifies all possible hazards and analyses risk and evaluate risk significance and implements appropriate risk reduction measures/controls to prevent, manage and mitigate identified hazards and risks throughout the entire pipeline life cycle.* No adverse findings.	*NA*
2.1 Organizational Roles and Responsibilities	*Requirement/Expectation: The Organizational Roles and responsibilities subcomponent requires that a permit holder document and keep current the assignment of roles and responsibilities associated with the development, implementation, and maintenance of the IMP.* No adverse findings.	*NA*

IMPP Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
2.2 Communication	*Requirement/Expectation: The Information Management and Communication subcomponent requires that a permit holder establish and implement a process for internal and external communication to coordinate information essential to the IMP.* No adverse findings.	*NA*
2.3 Training and Competency	*Requirement/Expectation: The Training and Competency subcomponent requires that a permit holder assess and document the training and competency requirements for its employees to ensure appropriate knowledge and skills for performing the elements of the IMP for which they are responsible. Process for contractor/consultant selection, oversight and evaluation is also required.* No adverse findings.	*NA*
2.4 Managing Change	*Requirement/Expectation: The Managing Change subcomponent requires that a permit holder develop and implement a systemic process to ensure that prior to implementation, changes that may impact the integrity of the pipeline system at any life cycle phase are evaluated, controlled and documented for their potential risk impacts.* No adverse findings.	*NA*
2.5 Record and Document Controls	*Requirement/Expectation: The Record and Document Controls subcomponent requires that a permit holder prepare and manage documents and records related to pipeline design, construction, commissioning, operation, maintenance, and abandonment that are needed for performing the activities included in the IMP.* No adverse findings.	*NA*

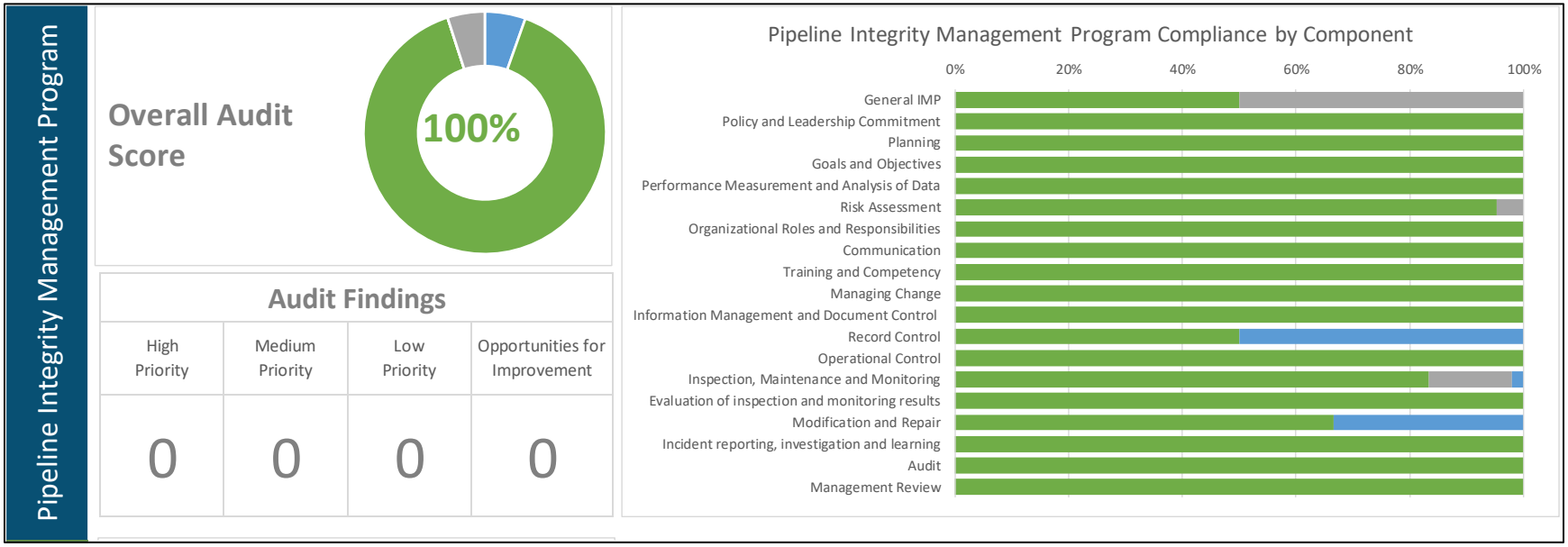
IMPP Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
2.6 Operational Control	*Requirement/Expectation: The Operational Control subcomponent requires that permit holders develop and implement procedures to record and identify deviations and upset operating conditions and to determine any immediate or long-term implications. Operational conditions must be monitored to detect and assess any changes (such as pressure cycles, overpressure, and over temperature). The permit holder must also develop and implement contingency plans for such situations.* No adverse findings.	*NA*
2.7 Inspection, Maintenance and Monitoring (IMM)	*Requirement/Expectation: The Inspection and Monitoring subcomponent requires that a permit holder establish and implement the methods and procedures of inspections, testing, patrols and monitoring in accordance with CSA Z662 clauses 9 and 10, and as appropriate, clause 12.* No adverse findings.	*NA*
2.8 Evaluation of Inspection, Maintenance and Monitoring Results	*Requirement/Expectation: The Evaluation of Inspection, Maintenance and Monitoring Results subcomponent requires that a permit holder conduct an engineering assessment as per Clause 10.3.2.1 or take corrective actions as per Clause 10.3.2.3, when the inspection, testing, patrol, or monitoring results indicate the presence of conditions or imperfections that might lead to failure.* No adverse findings.	*NA*
2.9 Modification and Repair	*Requirement/Expectation: The Modification and Repair subcomponent requires that permit holders document and maintain procedures to modify or repair conditions or imperfections that could cause failure or damage with significant consequences.* No adverse findings.	*NA*

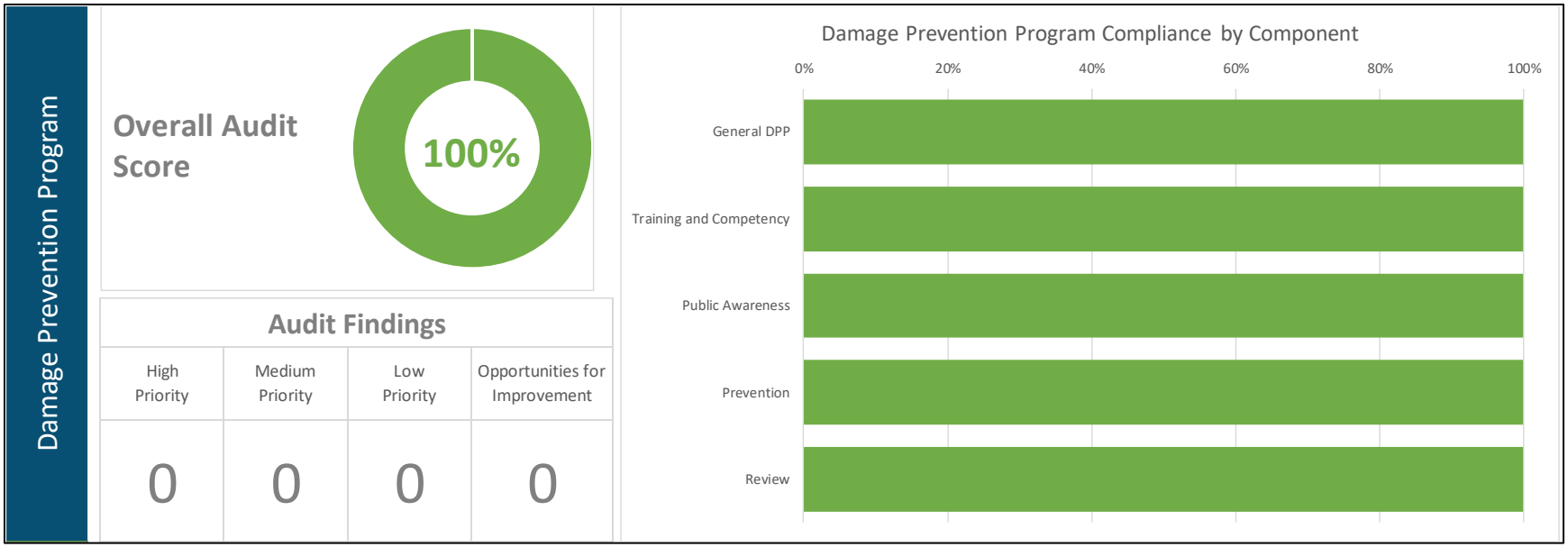
IMPP Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
3.1 Incident Reporting, Investigation and Learning	*Requirement/Expectation: The Incident Reporting, Investigation and Learning subcomponent requires that a permit holder document and implement its process to report and investigate any hazards, potential hazards, incidents or near misses affecting or having the potential to affect the integrity of the pipeline system.* No adverse findings.	*NA*
3.2 Internal Audit	*Requirement/Expectation: The Internal Audit subcomponent requires that a permit holder develop and implement a process for internal auditing of its IMP program.* No adverse findings.	*NA*
3.3 Performance Measurement and Analysis of Data (KPIs)	*Requirement/Expectation: The Performance Measurement and Analysis of Data subcomponent requires that a permit holder establish, maintain, analyze and trend metrics or key performance indicators (KPIs) for implementing its goals and objectives and for evaluating the performance of its integrity management program.* No adverse findings.	*NA*
4.0 Management Review	*Requirement/Expectation: The Management Review component requires that a permit holder establish and implement a regular management review process to determine the adequacy, implementation, and effectiveness of its integrity management program.* No adverse findings.	*NA*

IMPP Components (as per Compliance Assurance Protocol)	Comments	Risk Priority
Damage Prevention Program (DPP)	*Requirement/Expectation: Section 7(2) of Pipeline Regulation requires that a permit holder must develop, implement, and establish a Damage Prevention Program (DPP) before operating any pipeline permitted in BC by focusing on public awareness, training and competency assessment, measures for damage prevention and continual review of DPP.* No adverse findings.	*NA*

3. Audit Performance Evaluation

FEI's audit findings are analyzed as compliance rate and risk ranked based on process, execution, scope, documentation, records, and administration. FEI's audit performance is graphically represented below:

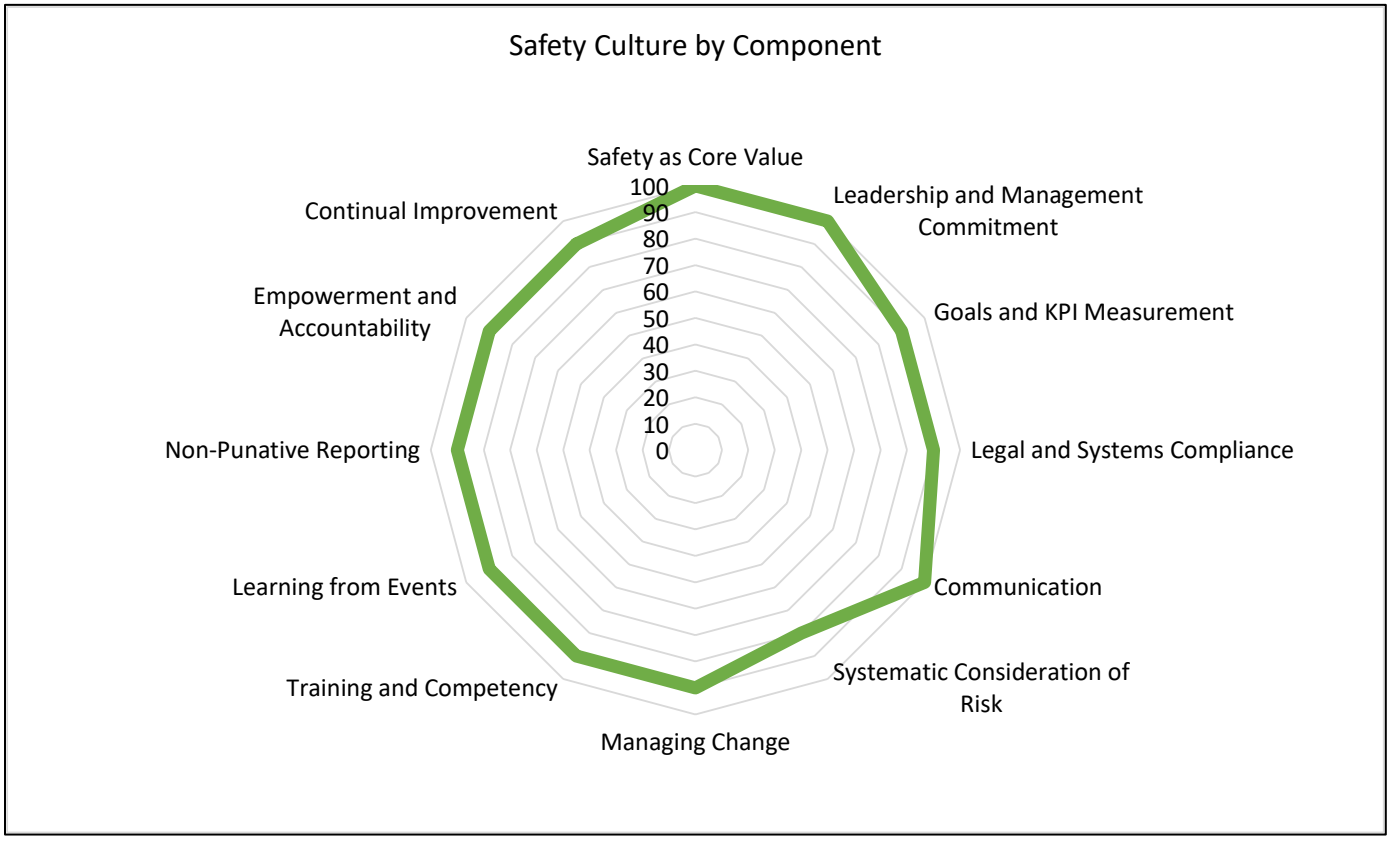



Damage Prevention Program
Overall Audit Score
100%
Audit Findings
High Priority
Medium Priority
Low Priority
Opportunities for Improvement
0
0
0
0
Damage Prevention Program Compliance by Component
0%
20%
40%
60%
80%
100%
General DPP
Training and Competency
Public Awareness
Prevention
Review

3.1 Safety Culture

(Same for IMPP and IMPF)

Safety culture and the implementation of a management system such as integrity management are directly related. Canadian standard, CSA Z662-19 (Annex A- A.1) outlines that awareness and understanding of human factors, organizational factors, organizational culture, and safety culture enable better anticipation and management of system hazards and risks to prevent system failures. The Safety Culture (SC) assessment used by the Commission is based on the IMPP audit. The Commission's SC assessment is interpreted through the hundred-point scale. For 12 SC indicators, values are assigned as 80-100 for most positive (strong), 50-70 for moderate responses, and 10-40 to represent the least positive indicators (weak). The radar / spider plot below presents the visualization of the overall findings of SC indicators and highlight where more action plans are required for improvement and should be given priority.



4. Corrective Action Submission and Review Process

FEI's IMPP and DPP audit determined that all expectations and requirements outlined in the Commission's IMP protocol for pipelines were met and no adverse findings were identified. The Commission expects FEI to remain committed and continue with improvement and advancement of their IMP. The Commission would like to thank FortisBC Energy Inc. (FEI) for its continued participation and cooperation in the Commission's compliance assurance process.