FASKEN

Fasken Martineau DuMoulin LLP
Barristers and Solicitors
Patent and Trade-mark Agents

550 Burrard Street, Suite 2900
Vancouver, British Columbia V6C 0A3
Canada

T +1 604 631 3131
+1 866 635 3131
F +1 604 631 3232

fasken.com

Christopher R. Bystrom
Direct 604 631 4715
Facsimile 604 632 4715
cbystrom@fasken.com

September 19, 2023
File No.: 240148.01029

Electronic Filing

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. ("FEI") Application for a Certificate of Public Convenience and Necessity for the Interior Transmission System Transmission Integrity Management Capabilities Project - Final Submission

In accordance with the regulatory timetable in the above proceeding, we enclose for filing the Final Argument of FortisBC Energy Inc., dated September 19, 2023.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by]

Christopher Bystrom*
*Law Corporation

Encl.

cc (email only): Registered Interveners.

BRITISH COLUMBIA UTILITIES COMMISSION

FORTISBC ENERGY INC.

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE INTERIOR TRANSMISSION SYSTEM TRANSMISSION INTEGRITY MANAGEMENT CAPABILITIES PROJECT

FINAL SUBMISSION OF

OF

FORTISBC ENERGY INC.

September 19, 2023

Prepared by: Fasken Martineau DuMoulin LLP - Christopher Bystrom and Niall Rand

TABLE OF CONTENTS

PART ONE: INTRODUCTION

1. FEI submits that the evidence it has filed in this proceeding overwhelmingly demonstrates that the Interior Transmission System Transmission Integrity Management Capabilities Project (Project or ITS TIMC Project) is in the public interest. As described in FEI's Application,[1] the Project is necessary to ready 8 Interior Transmission System (ITS) pipelines for electro-magnetic acoustic transducer (EMAT) in-line inspection (ILI) tools. These EMAT ILI tools are the only technically and financially feasible alternative to mitigate cracking threats. Cracking is now known to be a greater threat to pipeline integrity than previously understood by industry, and FEI's physical inspections have confirmed that cracking already exists on the 8 ITS pipelines. Notably, out of 641 integrity digs, FEI found 329 different locations of cracking on these pipelines.[2] The susceptibility of these pipelines to cracking that can lead to failure has also been confirmed by an expert consultant, Jana Corporation (JANA), in conjunction with Dr. Weixing Chen of the University of Alberta.[3]

2. The imperative for FEI to adopt EMAT ILI for the 8 ITS pipelines is heightened by the fact that the threat of cracking on these pipelines can lead to failure by rupture. Pipeline ruptures are unacceptable to FEI. Numerous incidents in the pipeline industry have shown that failure by rupture can have significant adverse consequences. Potential consequences of a rupture of the 8 ITS pipelines include loss of life, damage to property, inability to serve customers during winter and forest fires.[4]

3. FEI's analysis on cracking and the need to adopt EMAT ILI is supported by the Independent Report of Dynamic Risk Assessment Systems Inc. (Dynamic Risk), a pipeline integrity expert.[5] The BCUC retained Dynamic Risk to produce an independent expert report (Independent Report) and relied on its findings in Decision and Order C-3-22 (CTS TIMC Decision).[6] The CTS TIMC Decision, which granted a CPCN for FEI's Coastal Transmission System Transmission Integrity Management Capabilities (CTS TIMC) Project to prepare FEI's CTS pipelines for EMAT ILI, also strongly supports the ITS TIMC Project. Notably, the BCUC affirmed in the CTS TIMC Decision that "there is a need to mitigate the risk of undetected cracks that FEI's

---

1 Exhibit B-1, Application to the British Columbia Utilities Commission for a Certificate of Public Convenience and Necessity for the Interior Transmission System Transmission Integrity Management Capabilities Project.

2 Exhibit B-1, Application, Table 3-4.

3 B-1-1, Confidential Application, Appendix B-2

4 Exhibit B-1, Application, p. 53; Exhibit B-7, CEC IR1 14.1.

5 Exhibit B-1, Appendix O-1.

6 https://docs.bcuc.com/documents/proceedings/2022/doc_66603_c-3-22-fei-cts-timc-cpcn-decision.pdf.

existing tools and techniques are insufficient in addressing" and that the risk of rupture caused by undetected cracking is "unacceptable".[7] FEI submits that these conclusions are equally applicable to the ITS TIMC Project.

4. The BC Energy Regulator (BCER) has also indicated its support for FEI's efforts to enhance its response to cracking threats. In response to a request by the BCER, FEI presented it plans to address cracking threats on its pipelines[8] and the BCER has since issued a letter of support for FEI taking action to address its known integrity concerns in alignment with its regulatory and legal responsibilities.[9] Consistent with the BCER's letter of support, FEI must continue meeting its obligations to ensure the safety and security of its pipeline operations. Adopting EMAT ILI for the 8 ITS pipelines will allow FEI to keep pace with evolving industry practice and regulatory expectations for managing the safety risk posed by cracking threats.[10]

5. Therefore, FEI submits that the BCUC should grant a Certificate of Public Convenience and Necessity (CPCN) for the Project and grant FEI's other requested relief set out in the Application. A draft order sought is included as Appendix Q-2 of the Application.

6. The remainder of this submission is organized as follows:

- Part Two discusses how the Project is necessary and justified.
- Part Three discusses how FEI identified the available alternatives and correctly concluded that EMAT ILI is the only feasible and preferred alternative.
- Part Four describes the evidence filed on the Project scope, and focuses on the need for pressure reduction capabilities and the proactive replacement of 3 heavy wall pipe segments, the timing of the Project, and the robustness of the Project's AACE International (AACE) Class 3 cost estimate for the Project.
- Part Five describes the potential archaeological and environmental impacts caused by the Project, all of which can be appropriately mitigated.

---

7 BCUC Decision and Order C-3-22, p. 11.
8 Exhibit B-19, BCUC IR3 30.2.
9 Exhibit B-1, Appendix C.
10 Exhibit B-1, Application, p. 13.

- Part Six describes how FEI's public consultation and early engagement with Indigenous groups has been sufficient and reasonable to date and will continue throughout the life of the Project.

- Part Seven describes how the Project is consistent with British Columbia's energy objectives and long-term gas resource plans, as well as aligning with FEI's decarbonization goals.

- Part Eight concludes this Final Submission.

PART TWO: THE PROJECT IS NECESSARY AND JUSTIFIED

7. FEI submits that the need for the Project is compelling and has not been subject to material challenge through the evidentiary phase of this proceeding. This Part discusses how the Project is necessary and justified, and is organized around the following key points:

- Industry knowledge, physical inspection, and an expert risk assessment demonstrates that the 8 ITS pipelines are subject to the threat of cracking.
- FEI's existing integrity management practices only allow for a small portion of the ITS pipelines to be assessed for cracking.
- FEI's EMAT ILI pilot project was successful and demonstrates that previously undetected cracking exists on the gas system.
- FEI must mitigate cracking on the ITS to maintain compliance with statutory and regulatory obligations, align with evolving industry practice and meet its duty to maintain the safety of its ITS pipelines.

A. <u>There is a Confirmed Threat of Cracking on the 8 ITS Pipelines</u>

8. The need for the Project is supported by evolving industry knowledge regarding the threats posed by cracking and expert risk assessments concluding that the 8 ITS pipelines are susceptible to cracking threats that can grow to failure, consistent with the physical evidence of cracking that FEI has found on the 8 ITS pipelines to date. This evidence is summarized below.

(a) Industry Knowledge of Cracking Threats and Means to Mitigate Have Improved

9. The need for the ITS TIMC Project is driven by the evolution of industry knowledge about cracking threats and industry practice on how to manage those threats.[11]

10. Cracking threats are cracks or "planar imperfections"[12] in a pipe that effectively reduce the wall thickness of the pipeline, thereby affecting the strength of the pipeline. The two main types of cracking threats to FEI's system are stress corrosion cracking (SCC) and crack-like imperfections in the seam weld of a pipeline. SCC and crack-like imperfections can also interact with other time-dependent integrity

---

[11] Exhibit B-1, Application, Section 3.3.

[12] Cracks have a measurable length and depth, but are sufficiently narrow that they do not typically have a measurable width associated with their dimensions.

threats, such as external corrosion, resulting in compounded integrity issues on a pipeline.[13] Cracking develops when the following three factors are present: (1) a susceptible metallic material (e.g., all pipeline steels, albeit to varying degrees); (2) a tensile stress; and (3) a suitable environment. Due to variability in these factors, the formation and growth of cracks is a complex, highly localized and often unpredictable process.[14] Importantly, it is not possible to pinpoint the exact locations where cracking will occur by assessing the factors that cause it, which limits the efficacy of existing mitigation techniques.[15]

11. Industry has learned that cracking poses a greater threat to pipeline integrity than previously believed, thus necessitating active monitoring and mitigation. As JANA observes in its *Analysis of Cracking Threats in FEI Mainline Transmission Pipelines* report (discussed further in Part Two, Section A(b) below):[16]

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

Indeed, industry data demonstrates that SCC has led to pipeline failures on pipelines similar to those operated by FEI (i.e., pipelines with similar coatings, age, diameters, and operating stress level).[17]

12. Industry has also evolved in how it responds to these cracking threats.[18] Specifically, EMAT ILI is being adopted by industry for managing cracking threats on transmission pipelines that are large enough to accommodate the tools.[19] As explained by Dynamic Risk in its Independent Report, EMAT ILI has evolved and expanded in prevalence within the industry in its management of cracking threats:[20]

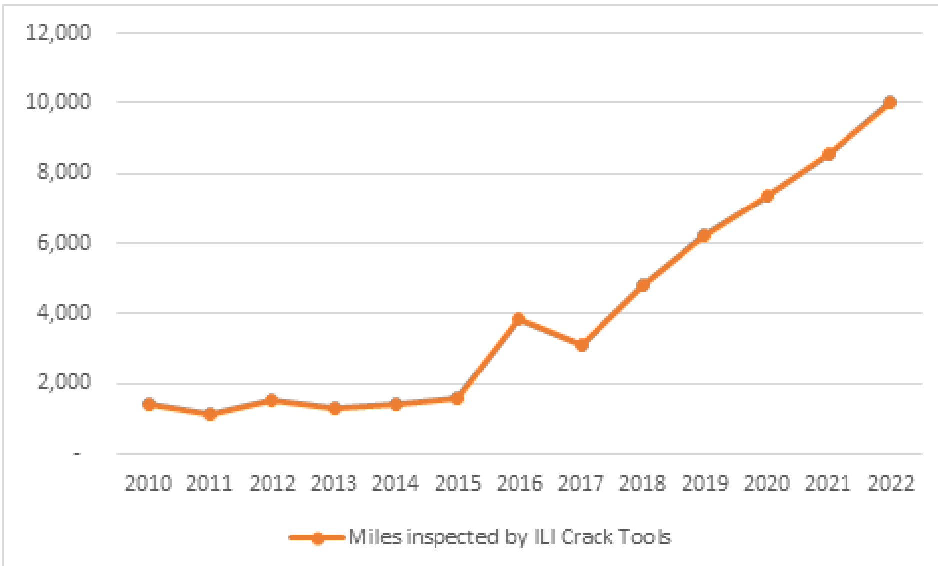
> For natural gas pipelines, the management of SCC has benefited from the introduction and evolution of ILI technologies, specifically EMAT technology, that can reliably detect, identify, and size cracking anomalies. Since it's introduction in the early 2000's, the performance of EMAT technology has been evaluated and documented through many industry research projects and published articles that describe operational experience.

---

13 Exhibit B-1, Application, p. 26.
14 Exhibit B-1, Application, pp. 27-28.
15 Exhibit B-1, Application, p. 30.
16 Exhibit B-1-1, Confidential Application, Appendix B-1, p. 5.
17 Exhibit B-1, Application, p. 31.
18 Exhibit B-1, Application, p. 31.
19 Exhibit B-1, Application, p. 31.
20 Exhibit B-1, Application, Appendix O-1, p. 18.

13. In fact, industry practice has now evolved to recognize EMAT ILI as the industry standard for managing the risk of pipeline rupture due to cracking threats on transmission pipelines.[21] For example, as shown in the figure below, the miles of gas transmission pipelines inspected in each year using EMAT ILI tools in the US has increased from 1,429 miles in 2010 to 10,036 miles in 2022.[22]

Figure 1: Gas Transmission Miles Inspected by ILI Crack Tool - HCA and Non-HCA, US PHMSA-Regulated



14. In short, EMAT ILI tools are the best available technology for mitigating cracking threats in natural gas pipelines and are now the industry standard approach.[23]

15. As a prudent operator, FEI must enhance its integrity management practices to reflect the improved understanding of the threat of cracking to its pipelines and industry standard practices for addressing those threats.

(b) The ITS is Susceptible to Cracking Threats That Have the Potential to Grow to Failure

16. Given the increased understanding of the threat posed by cracking, FEI retained JANA to conduct two related studies to assess the susceptibility of FEI's transmission pipelines to cracking threats.[24] JANA's first report, titled *Analysis of Cracking Threats in FEI Mainline Transmission Pipelines* and attached as

---

21 Exhibit B-1, Application, pp. 30-31.
22 Exhibit B-22, RCIA IR3 26.2.
23 Exhibit B-4, BCUC IR1 4.1.
24 See Exhibit B-1, Application, pp. 33-34 for a description of each system.

Confidential Appendix B-1 to the Application,[25] assesses the susceptibility of FEI's transmission system pipelines to cracking.[26] FEI optimized the scope of work to transmission pipelines of NPS 10 or greater that have previous geometry and MFL ILI data, and for which EMAT ILI tools are commercially available.[27] The assessment comprised a line-by-line assessment of:

- "Susceptibility"[28] to cracking threats for each system based on pipeline properties and operating conditions compared with those where historical failures have been observed in industry;[29]
- Historical cracking found on FEI pipelines;
- Industry historical failures and crack growth modelling to determine the potential for cracks to grow to failure; and
- The estimated contribution of cracking threats to overall frequency of failure and risk based on the QRA.[30]

17. In applying susceptibility ratings to each of the assessed pipelines, JANA considered criteria such as the installation year and whether the coating used on the pipeline has been found to be associated with the formation of SCC and seam weld cracking.[31] As shown in Table 3-3 of the Application, JANA concluded that 9 of the 12 ITS pipelines considered were "susceptible"[32] to cracking threats by confirming that these pipelines have characteristics consistent with those of pipelines where SCC has been historically identified in the pipeline industry.[33] Although assessed by JANA as susceptible to cracking, FEI excluded the Trail-Castlegar NPS 8 pipeline from the Project scope on the basis that EMAT ILI tools are not

---

25 Exhibit B-1-1, Confidential Application.
26 Exhibit B-1, Application, Section 3.4.3.
27 Exhibit B-8, RCIA IR1 8.2.
28 The term "susceptible" is used by JANA to indicate the potential for SCC or pipe seam cracking to initiate on the lines, based on the specific characteristics of the lines and their operating conditions: Exhibit B-1, Application, p. 36.
29 This analysis included consideration of PHMSA and NEB databases and technical publications and discussions with FEI Subject Matter Experts: Exhibit B-1, Application, p. 35. As FEI confirmed in the response to CEC IR1 3.1 (Exhibit B-7), the initial selection of its pipe manufacturer (when compared to other manufacturers) has not contributed to the current susceptibility to cracking threats.
30 Exhibit B-1-1, Confidential Application, Confidential Appendix B-1, p. 4.
31 Exhibit B-1, Application, p. 36.
32 A "yes" susceptible line is one where the characteristics of the line are consistent with lines where SCC or pipe seam cracking has been observed on multiple systems within the broader pipeline industry. A "low" susceptible line is one with characteristic where no or very limited failures have historically been observed in the industry: Exhibit B-1-1, Confidential Application, Confidential Appendix B-1, p. 4 and Exhibit B-6, BCOAPO IR1 1.9.
33 Exhibit B-1, Application, p. 37.

commercialized and available for pipelines with diameters smaller than NPS 10.[34] The methodology used to assess susceptibility aligns with guidance outlined by the Canadian Energy Pipeline Association (CEPA).[35]

18. Importantly, JANA's conclusions regarding the susceptibility of FEI's transmission pipeline are confirmed by the cracking that FEI has already found on its system through opportunity digs. For example, of the 92 opportunity digs undertaken on the SAV VER 323 pipeline, FEI identified 50 instances of cracking. Further occurrences are summarized in Table 3-4 of the Application, as reproduced below.[36] As shown in the table, FEI has found 329 instances of cracking threats on the 8 ITS pipelines from inspections that have covered only a small fraction of the length of the pipelines.[37]

---

34 Exhibit B-6, BCOAPO IR1 1.8.1.

35 Exhibit B-6, BCOAPO IR1 1.9.

36 Exhibit B-1, Application, p. 39; see also Exhibit B-6, BCOAPO IR1 1.8.

37 Inspections to date total only approximately 1 percent of the length of the total length of pipe in FEI's transmission systems: Further, only a small portion of pipe is exposed for each dig (in the order of 10 metres): Exhibit B-1, Application, pp. 29-30.

Table 3-4: FEI ITS Pipelines: Occurrences of Cracking 1 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 Analyzed
1	SAV VER 323	Savona – Vernon 12"	Yes	Yes	50	92
2	VER PEN 323	Vernon – Penticton 12"	Yes	Yes	38	67
3	GRF TRA 273	Grand Forks – Trail 10"	Yes	Yes	138	228
4	OLI GRF 273	Oliver Y – Grand Forks 10"	Yes	Yes	79	163
5	PEN OLI 273	Penticton – Oliver Y 10"	Yes	Yes	13	23
6	TRA CAS 219	Trail – Castlegar 8"	Yes	Yes	11	76
7	KIN PRI 323	Kingsvale – Princeton 12"	Yes	Low	0	3
8	PRI OLI 323	Princeton – Oliver 12"	Yes	Low	2	12
9	YAH TRA 323	Yahk – Trail (ELK) 12"	Yes	Low	9	53
10	OLI PEN 406	Oliver – Penticton 16"	Low	Low	0	1
11	DUK SAV 508	Duke Tap – Savona C/S 20"	Low	Low	0	0
12	YAH OLI 610	Yahk – Rossland 24", Rossland – Oliver 24"	Low	Low	0	6

19. JANA's analysis completed in conjunction with Dr. Weixing Chen of the University of Alberta also confirms that cracks on the ITS pipelines can grow to failure.[38] More specifically, Dr. Chen's analysis of FEI's system determined that cracks could grow to failure in a range of times, namely, from 5 to 85 years.[39] 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 indicates that cracking is a credible integrity threat that needs to be managed in a timely manner.[40]

20. Given the analysis of the threat of cracking on the 8 ITS pipelines, active monitoring and mitigation is needed.

---

38 Exhibit B-1, Application, pp. 39-41. As discussed in the response to BCOAPO IR1 1.7 (Exhibit B-6), Dr. Chen's assessment incorporates both theoretical assumptions and consideration of specific characteristics with respect to the actual FEI ITS pipelines. See also Exhibit B-1-1, Confidential Application, Appendix B-1, pp. 14-16 and Appendix A (Analysis of SCC Failures of Pipeline Steels with Low and Medium Operating Hoop Stresses); and Exhibit B-9, BCUC IR2 19.1.

39 Exhibit B-1, Application, p. 41.

40 Exhibit B-1, Application, p. 41.

(c) Results of the QRA Confirm Cracking is a Safety Risk on the ITS Warranting Prioritization

21. JANA's second report, titled *Quantitative Safety Risk Assessment of FEI Mainline Transmission Pipelines* and attached as Confidential Appendix B-2 to the Application, provides the results of a baseline, system-level, safety QRA of the ITS, CTS and VITS.[41] A QRA is a formal and systematic approach to estimating the probability and consequences of hazardous events which is an accepted method for transmission operators to comply with the CSA Z662 standard.[42] JANA's QRA quantifies and ranks the safety risk posed by cracking threats in comparison to other threats and hazards[43] and, therefore, the results of the QRA inform the timing of the ITS TIMC Project relative to the CTS TIMC Project.[44] As outlined below, JANA's model estimates that cracking threats are the second highest threat for 7 of the 9 ITS pipelines identified as being susceptible to cracking threats and the third highest threat for the other 2 susceptible ITS pipelines.[45]

22. 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 ITS, CTS and VITS).[46] First, the QRA estimates that cracking threats are the highest contributor to <u>safety risk and rupture rate</u> for the 9 ITS pipelines that JANA identified as being susceptible to cracking.[47] Second, as noted above, cracking threats represent the second highest <u>overall</u> threat to 7 of the 9 ITS pipelines, behind only the risk of third-party damage,[48] and the third highest threat for the 2 of the 9 ITS pipelines, behind only third-party damage and natural hazards.[49]

---

41 Exhibit B-1, Application, Section 3.4.4.

42 The CSA Z662 standard requires operators to develop, implement, and continually improve a risk management process for their pipeline systems that identifies, assesses, and manages the hazards and associated risks over their life cycle: Exhibit B-1, Application, pp. 41-42.

43 The baseline QRA assessed over 20 potential threats, including: external corrosion, internal corrosion, stress corrosion cracking, excavation damage, manufacturing defects, construction defects, and earth movements: Exhibit B-1, Application, p. 42, fn. 25.

44 Exhibit B-6, BCOAPO IR1 1.10.

45 Exhibit B-1, Application, p. 48.

46 Exhibit B-1, Application, Appendix B-2, pp. 9-11.

47 Exhibit B-1, Application, p. 43; see also Exhibit B-8-1, Confidential RCIA IR1 8.4 which shows the safety risk for the 12 ITS pipelines assessed as part of the QRA.

48 Third-party damage refers to external interference such as third-party contact with the pipeline or vandalism. 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: Exhibit B-1, Application, p. 43 and Exhibit B-4, BCUC IR1 3.1.

49 Exhibit B-1, Application, p. 43 and Appendix B-2; see also Exhibit B-4-1, BCUC IR1 3.2.

23. FEI explained why third-party damage was more highly ranked, on a relative basis, for ITS pipelines than for the CTS pipelines:[50]

- According to JANA's model, the smaller diameter of ITS pipelines are considered to be less susceptible to cracking compared to the larger CTS pipeline;
- The location of ITS pipelines in a mix of densely populated and unpopulated areas creates a lower immediate safety consequence compared to the CTS pipelines which are located in more densely populated areas; and
- The ITS pipelines have a lesser initial as-constructed depth of cover, thus increasing the risk of third-party damage occurring compared to CTS pipelines which were installed to different installation practices and in different terrain.

24. For context, between 2017 and 2022, FEI had a total of two third-party line damages to its transmission system, both of which were on the ITS.[51] The risk associated with these (and other integrity threats) are managed through FEI's integrity management and capital programs,[52] and FEI continues to explore practical and cost-effective activities to manage third-party damage threats and natural hazards.[53]

25. In summary, the QRA confirms that cracking is a safety risk to the ITS pipeline. Regardless of its ranking relative to other threats, the potential for pipeline rupture due to cracking warrants an enhancement to FEI's active integrity management of this threat.

B. <u>FEI's Existing Integrity Management Practices Only Allow a Small Portion of Pipelines to be Assessed for Cracking</u>

26. While there is a need to mitigate the threat of cracking on the 8 ITS pipelines, FEI's current integrity management practices are unable to identify all cracking threats on the pipelines.[54]

---

[50] Exhibit B-4, BCUC IR1 3.1.1. See also Exhibit B-4, BCUC IR1 3.1 which outlines the methodology and assumptions used to evaluate the threat of third-party damage to FEI's pipeline system.

[51] The term "damage refers to a failure event that involved a release of natural gas: Exhibit B-9, BCUC IR2 18.1.

[52] For example, as outlined in the response to BCUC IR1 3.3 (Exhibit B-4) , FEI develops and implements practical and cost-effective measures to mitigate the potential for rupture due to both third-party damage and natural hazards. Further, FEI primarily monitors for potential security threats to its transmission pipelines (a form of third-party damage) through visual inspections of its system: Exhibit B-10, CEC IR2 42.1.

[53] Exhibit B-9, BCUC IR2 18.3.

[54] Exhibit B-1, Application, p. 5.

27. The cracks that are a threat to pipelines are too narrow (i.e., lack volume) to be detected by FEI's current ILI tools.[55] As explained by Dynamic Risk in the Independent Report:[56]

> SCC is a form of environmentally assisted cracking; wherein small surface cracks can form and grow over time. Cracks that continue to grow will frequently overlap and/or coalesce to become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. Eventually such overlapping and coalescence can create a crack of sufficient size to cause the pipeline to leak or rupture. It is the independent pipeline integrity expert panel's view that SCC is a credible threat for FEI that if left unmitigated, could lead to pipeline failure.

28. Therefore, FEI currently relies on "opportunity digs" to manage cracking, which provide an opportunity to inspect for cracking, even though inspecting for cracking is not the primary reason for the integrity dig. FEI is aware of the existence of cracking threats on its system through these opportunity digs, and to date, has addressed any identified cracking through pipeline repairs or replacement, as necessary.[57]

29. However, opportunity digs only provide the capability to assess a small portion of FEI's pipelines for cracking threats.[58] A typical dig on a pipeline will only expose in the order of 10 metres of a pipeline that is many kilometres long.[59] Further, the results of an opportunity dig are only applicable to the limited section exposed and not the entire length of the pipeline.[60] Given the highly localized and often unpredictable nature of cracking, a lack of cracking in one relatively short length of pipe cannot be extrapolated to other locations. FEI estimates that the total amount of pipeline exposed to date and assessed for cracking is less than one percent of the total length of pipe in FEI's transmission system, leaving approximately 99 percent of FEI's system unassessed for cracking.[61]

30. The BCUC affirmed in the CTS TIMC Decision that: "…there is a need to mitigate the risk of undetected cracks that FEI's existing tools and techniques are insufficient in addressing" and agreed with FEI's submissions that the risk of rupture caused by undetected cracking is "unacceptable".[62] The BCUC's conclusion is also consistent with that of Dynamic Risk, which stated the following in its Independent

55 Exhibit B-1, Application, p. 26.
56 Exhibit B-1, Application, Appendix O-1, p. 30.
57 See Exhibit B-8, RCIA IR1 6.3 which identifies when cracking was first found on each of the 8 ITS pipelines; see also Exhibit B-1, Application, pp. 29-30.
58 Exhibit B-1, Application, p. 30.
59 Exhibit B-1, Application, p. 30.
60 Exhibit B-1, Application, p. 30.
61 Exhibit B-1, Application, p. 30.
62 BCUC Decision and Order C-3-22, p. 11.

Report: "…Currently, there is a gap in the existing FEI integrity management practices to address the threat of SCC, as opportunistic excavations alone are not sufficient to fully characterize, detect and manage the threat."[63] Dynamic Risk's assessment endorses the need to address SCC, which should be given significant weight by the BCUC in this proceeding.

C. FEI's EMAT ILI Pilot Project Demonstrates Previously Undetected Cracking Threats

31. Given the advancement in knowledge of the threat of cracking both internally and within industry, and given the commercialization of EMAT ILI tools, FEI undertook an EMAT ILI pilot project to assess cracking on two CTS pipelines.[64] As explained further in Appendix D to the Application, the pilot project has informed the development and planning of both the CTS and ITS TIMC projects (TIMC projects), including the behaviour of the EMAT ILI tool performance and especially how these tools perform in comparison to the MFL-A and MFL-C tools.[65] This information was critical for refining the scope of the ITS TIMC Project and, in particular, identifying and selecting only the heavy wall segments with a high probability of causing EMAT tool speed excursions (as discussed further in Part Four, Section A(b) below).[66]

32. The two pipelines were selected for the pilot project after cracking was discovered during opportunity digs, and FEI determined that the required modifications to run EMAT ILI tools could be completed on a timeline to inform the TIMC projects.[67] The runs undertaken as part of the pilot project detected instances of potential cracking that FEI had not previously detected through opportunity digs.[68] FEI has now confirmed the results of the runs undertaken as part of the pilot project, with all of the tool-reported features being excavated and inspected, and almost all of the features identified demonstrated as valid.[69] Importantly, because cracking is highly localized and often unpredictable, FEI cannot extrapolate the findings from the pilot project to determine where cracking may be occurring on other segments of pipeline not yet assessed using EMAT ILI.[70] Even so, the pilot project results demonstrate that EMAT ILI can detect cracking on FEI's pipelines that would otherwise have gone undetected and,

---

63 Exhibit B-1, Application, Appendix O-1, p. 30.
64 The pipelines selected are CPH BUR 508 and LIV PAT 457, both of which are on the CTS: Exhibit B-7, CEC IR1 8.1. These pipelines, totalling 34 km make up approximately 13 percent of the total CTS length: Exhibit B-8, IR1 7.4.
65 Exhibit B-1; Exhibit B-5, BCOAPO IR1 1.4.
66 Exhibit B-1, Application, Appendix D, p. 7.
67 Exhibit B-1, Application, p. 32.
68 Exhibit B-1, Application, p. 33.
69 Exhibit B-8, RCIA IR1 7.2 and 7.3.
70 Exhibit B-1, Application, p. 30.

therefore, EMAT ILI inspection of each individual line is required to collect the necessary information to determine if cracking is present on FEI ITS pipelines.

D. FEI Must Mitigate Cracking Threats on the 8 ITS Pipelines To Maintain Compliance With Statutory and Regulatory Obligations, Align With Evolving Industry Practice, and Meet its Duty to Maintain the Safety of its ITS Pipelines

33. Ultimately, this Project is driven by the need to address the potential safety and other consequences of a rupture caused by cracking threats. Based on industry evidence regarding the risk of pipeline rupture, the 8 ITS Pipelines have the potential to fail by rupture. It is accepted by the Canadian pipeline industry that a pipeline operating at or above 30 percent of SMYS has a potential to fail by rupture, whereas a pipeline operating below 30 percent of SMYS has a potential to leak.[71] This threshold has been adopted by CSA Z662 as the delineation between a transmission pipeline and a gas distribution system.[72] FEI's pipelines on the ITS operate at above 30 percent of SMYS and, therefore, have the potential to fail by rupture.

34. The consequences of a rupture can be significant, and include:[73]

- **Safety Consequences:** An ignited pipeline rupture can have significant safety impacts beyond the immediate area surrounding the pipeline, potentially resulting in near and widespread harm due to the ensuing fire and associated thermal effects on people and property. While the ITS operates in some lower population areas, the risk of wildfires resulting from an ignited rupture on an ITS pipeline is elevated in the Interior because of its expansive woodlands and vegetation, and the dry conditions particularly prevalent in the hot summer months.

- **Reliability Consequences:** In the absence of a redundant gas supply source, a pipeline rupture could result in loss of supply to FEI's customers, potential causing safety and economic consequences for residential, commercial and industrial customers.

- **Environmental Consequences:** A pipeline rupture could result in damage to the natural environment, potentially impacting aquatic and terrestrial resources, in addition to degraded air quality and greenhouse gas emissions. The environmental consequences

[71] Exhibit B-1, Application, p. 49.
[72] Exhibit B-1, Application, p. 49.
[73] Exhibit B-1, Application, p. 50.

associated with a pipeline rupture or a sudden and uncontrolled release of natural gas would be classified as a Level 2 Major or Level 3 Serious reportable incident by the BCER. In addition, the release of gas by rupture would be considered a reportable incident under the *Environmental Management Act Spill Reporting Regulation* for transmission pipelines.

- **Regulatory Consequences:** In alignment with the Canadian transmission pipeline industry, and as discussed further below, FEI and the BCER consider that a failure by rupture of FEI's natural gas pipelines to be a significant incident and not acceptable performance within FEI's IMP-P.

FEI has provided a number of examples of natural gas pipeline ruptures illustrating their potentially significant and extended consequences including, in particular, the Enbridge (Westcoast) NPS 36 natural gas transmission pipeline which occurred in October 9, 2018.[74]

35. In the case of the 8 ITS pipelines, the reliability consequences of a rupture are particularly significant, as they are generally not looped, meaning the gate stations and laterals fed by these pipelines are not supported by other pipelines. If a pipeline failure occurs, especially during cold winter conditions, gas supply to communities fed by these gate stations and laterals could be lost, leaving residents with an inability to heat their homes, and result in potential safety consequences.[75]

36. Given that FEI has already found hundreds of instances of cracking threats on the ITS pipelines and the demonstrated failure potential from such threats, the Project is necessary ensure FEI's continued compliance with various laws, regulations, and standards regarding the safe and reliable operation of its gas system assets.[76] For example:[77]

- Section 37 (1) (a) of the *Oil and Gas Activities Act* (OGAA) requires FEI, as a BCER permit holder, to "prevent spillage" associated with the operation of pipelines operating at or above 700 kPa.

- FEI must also remain compliant with the CSA Z662 standard, which is prescribed by the *Pipeline Regulation* under the OGAA. In particular, Section 10.3.1 of the *Pipeline*

---

[74] Exhibit B-1, Application, pp. 51-53.
[75] Exhibit B-1, Application, pp. 53-57.
[76] Exhibit B-1; Exhibit B-4, BCUC IR1 7.1; Exhibit B-7, CEC IR1 1.1 and 1.2.
[77] Exhibit B-1, Application, p. 47.

Regulation requires that FEI's pipeline system integrity management program "include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions".

37. While laws and regulations related to the integrity of FEI's system are typically goal-oriented rather than prescriptive, meaning requirements are expressed as outcomes to be achieved rather than as descriptions of how to achieve those outcomes, these obligations directly correlate with the additional measures FEI is taking to mitigate the potential for failure of the 8 ITS pipelines due to cracking threats.[78]

38. The BCER has filed a letter of support for FEI to take actions to address its regulatory obligations. In 2019, at the request of the BCER, FEI presented its SCC management practices, including its intention to adopt EMAT ILI on its system and the components included in the Project scope (e.g., the need to undertake system modifications to prevent speed excursions).[79] As set out in the letter attached as Appendix C to the Application, following FEI's presentation, the BCER indicated that it is "supportive of FEI taking action to address its known integrity concerns" in alignment with the utility's regulatory and legal responsibilities as a BCER "permit holder" under the OGAA.[80] The BCER expects FEI to remain committed and continue with improvement and advancement of its IMP-P and is aware of the need to minimize speed excursions which can lead to unusable data.[81] Consistent with the BCER's expectations, the ITS TIMC Project demonstrates FEI's commitment to continually improving and advancing its IMP-P.[82]

39. FEI must also undertake the Project to keep up with industry standard practice for mitigating cracking threats. As demonstrated in the preceding sections of the Final Submission, there are industry-adopted and commercialized approaches (i.e., EMAT ILI) to eliminate or mitigate the cracking threats on pipelines of NPS 10 or greater.[83] As a prudent operator, FEI must align with industry best practices with respect to managing the integrity of its pipelines.

40. The BCUC has also acknowledged FEI's duty to ensure the safe operation of its pipelines and, in particular, mitigate the risk of undetected cracks. The BCUC recognized FEI's obligations to ensure the safety and security of its pipeline operations as part of its Decision with respect to FEI's Application for a

---

78 Exhibit B-1, Application, p. 47.
79 Exhibit B-19, BCUC IR3 30.2.
80 Exhibit B-1, Application, Appendix C.
81 Exhibit B-4, BCUC IR1 2.1; Exhibit B-19, BCUC IR3 30.2.
82 Exhibit B-4, BCUC IR1 2.2.
83 Exhibit B-1, Application, p. 48; Exhibit B-4, BCUC IR1 6.2.2.

CPCN for the Inland Gas Upgrade (IGU) Project. In that Decision, the BCUC stated that "the primary justification for the IGU Project relates to safety, specifically, safety of supply and the continued provision of natural gas without interruption to customers, as well as the physical safety of residents and others along and near the laterals."[84] The BCUC went on to conclude that "FEI has a duty to ensure the safety and security of individuals who may be injured due to an explosion emanating from a pipeline rupture and subsequent ignition."[85] In the CTS TIMC Decision, the BCUC affirmed in particular that "there is a need to mitigate the risk of undetected cracks that FEI's existing tools and techniques are insufficient in addressing" and that "it would be unacceptable from a safety and reliability perspective to expose the public to any undetected cracking risk, which can be avoided through proactive measures."[86]

41. Therefore, FEI submits that it is in the public interest for it to proceed with the ITS TIMC Project in order to remain compliant with its regulatory obligations, align with industry best practices and meet its duty to maintain the safe operation of the ITS. The potential consequences of not enhancing its integrity management practices to address cracking threats on the 8 ITS pipelines are significant and unacceptable to FEI.

---

84 BCUC Decision and Order G-12-20, FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project, p. 7. Online: https://docs.bcuc.com/Documents/Proceedings/2020/DOC_56891_2020-01-21-G-12-20-FEI-CPCN-IGU-Project-Decision.pdf.

85 BCUC Decision and Order G-12-20, p. 7.

86 BCUC Decision and Order C-3-22, pp. 11-12.

PART THREE: ALTERNATIVES ANALYSIS CORRECTLY IDENTIFIED THE PREFERRED ALTERNATIVE

42. FEI correctly identified EMAT ILI as the preferred, and only feasible, alternative to achieve the Project objective of enhancing FEI's integrity management capabilities to mitigate cracking threats to the 8 ITS transmission pipelines. As summarized in Table 4-1 of Application, reproduced below, FEI evaluated six available alternatives using non-financial and financial criteria. These alternatives are the same as those considered for the CTS TIMC Project[87] and FEI's approach to evaluating these alternatives is robust consistent with the approach taken with respect to the CTS TIMC Project[88] – which the BCUC determined was appropriate and adequate in that proceeding.[89] As shown in the table, EMAT ILI is the only alternative that is both technically and financially feasible and is, therefore, the preferred alternative for the ITS TIMC Project.

Table 4-1: Summary of Alternatives Evaluation

<table>
<tr><th>Alternative</th><th rowspan="7">Non-Financial Assessment</th><th>Technical Feasibility</th><th rowspan="7">Financial Assessment</th><th>Financial Feasibility</th></tr>
<tr><td>Alternative 1: SCCDA</td><td>Not Feasible</td><td></td></tr>
<tr><td>Alternative 2: PRS</td><td>Not Feasible</td><td></td></tr>
<tr><td>Alternative 3: HSTP</td><td>Not Feasible</td><td></td></tr>
<tr><td>Alternative 4: EMAT ILI</td><td>Feasible</td><td>Feasible</td></tr>
<tr><td>Alternative 5: PLR</td><td>Potentially Feasible</td><td>Not Feasible</td></tr>
<tr><td>Alternative 6: PLE</td><td>Potentially Feasible</td><td>Not Feasible</td></tr>
</table>

43. This Part is organized around the following key points:

- FEI conducted a careful and detailed analysis of all identified alternatives using a comprehensive decision-making framework.
- FEI correctly screened out alternatives that are not technically feasible.
- FEI correctly screened out alternatives that are not financially feasible.
- EMAT ILI is the only feasible alternative to meet the Project objective.

---

87 Exhibit B-7, CEC IR1 17.1.

88 Exhibit B-6, BCOAPO IR1 2.3.

89 BCUC Decision and Order C-3-22, p. 19.

A. FEI Analyzed All Identified Alternatives Using a Comprehensive Framework

44. In Section 4.2 of the Application, FEI describes each of the six currently available alternatives it identified to achieve the Project objective; namely, mitigating cracking threats on the 8 ITS pipelines within the Project's scope.[90] FEI used a "Good-Acceptable-Poor Choice" rating system to evaluate these alternatives against three non-financial criteria and one financial criterion.[91] As the ITS pipelines are generally not looped and interconnected, the application of an alternative to one pipeline generally impacts the operation of other connected pipelines and, therefore, FEI determined that a system level evaluation was appropriate.[92] FEI first assessed all of the six alternatives against the non-financial criteria to determine their technical feasibility. The three remaining alternatives that were found to be technically feasible were assessed using the financial criterion to assess their financial feasibility.[93] The results are summarized below.

B. Alternatives Screened Out as Not Technically Feasible

(a) Alternative 1: SCCDA Cannot Reliability Identify Cracking Threats

45. The SCCDA alternative is a predictive model made up of information collected and analyzed as part of a five-step assessment process, including the direct examination of certain sections on a pipeline. The integrity of sections of the pipeline that are not exposed during the integrity dig is inferred based on the process.[94] FEI concluded SCCDA is an "unacceptable choice" as it cannot be counted on to reliably identify the most significant, and therefore most likely to fail, cracking threats. This lack of reliability reflects the nature of cracking threats; namely, the highly randomized and unpredictable nature of such threats along susceptible pipelines. As such, predominantly indirect assessment methods of this kind have limited value in pin-pointing the location of the deepest cracks.[95] As explained in the response to CEC IR1 18.1, "FEI does not consider SCCDA to be an improvement over its status quo as it would increase costs without increasing FEI's confidence that cracking has been mitigated on its pipelines."[96] Dynamic Risk similarly concludes: "While SCCDA is a suitable method for determine a pipeline's potential susceptibility to SCC, this method will not reliably identify or size the cracking on the CTS pipelines and should therefore

---

90 Exhibit B-1, Application, pp. 58-67; see also Exhibit B-6, BCOAPO IR1 2.1.
91 Exhibit B-1, Application, Section 4.3.
92 Exhibit B-1, Application, p. 68.
93 Exhibit B-1, Application, p. 68.
94 Exhibit B-1, Application, pp. 58-59.
95 Exhibit B-1, Application, pp. 73-74.
96 Exhibit B-7, CEC IR1 18.1.

not be considered as an alternative to EMAT ILI."[97] While SCCDA can be used to assess lines to determine if cracking is a potentially significant threat, FEI has already identified that cracking is a credible threat on ITS pipelines.[98] Ultimately, on its own,[99] SCCDA is not considered an effective approach to SCC integrity management and FEI did not undertake a cost-estimate for this alternative.

(b) Alternative 2: PRS Leads to System Capacity Limitations

46. The PRS alternative involves permanently lowering the maximum operating pressure of a pipeline such that the resultant hoop stresses are reduced to below 30 percent of SMYS.[100] PRS can reduce the likelihood for SCC to cause an in-service pipeline rupture, as these SCC threats would instead be expected to result in leaks.[101]

47. However, implementation of PRS on the 8 ITS pipelines, which are located within three bi-directional sub-systems within the ITS,[102] would lead to capacity limitations and significant operational challenges. In particular, when any of the sub-systems are operated at a reduced pressure, the capacity requirements under current peak day demand cannot be met. FEI addresses each sub-system in turn below:

- **Kingsvale Control Station to Oliver Y Control Station:** The majority of capacity on the KIN PRI 323 and PRI OLI 323 pipelines, which make up this sub-system, is used to provide additional gas to FEI's CTS from TC Energy in Alberta. The pressure reduction required to achieve a hoop stress below 30 percent of SMYS would result in FEI being able to supply only approximately 30 percent of the gas that can be delivered to the CTS currently, thus negatively impacting supply diversity to the Lower Mainland. FEI would need to source additional supply in the open market to replace the balance of the gas, which would be challenging and costly given that the Enbridge T-South pipeline system is fully contracted

---

97 Exhibit B-1, Application, Appendix O-1, p. 13; see also Exhibit B-1, Application, Appendix O-2, PDF p. 37 (RCIA-Dynamic Risk IR2 9.2).

98 Exhibit B-1, Application, p. 74.

99 The NACE, which developed this approach, states that SCCDA should be complementary to other inspection methods such as ILI or hydrostatic testing: Exhibit B-1, Application, p. 74; see also Exhibit B-1, Application, PDF p. 37 (RCIA-Dynamic Risk IR2 9.3).

100 Exhibit B-1, Application, pp. 59-60.

101 Exhibit B-1, Application, p. 75.

102 The analysis of the PRS alternative cannot be performed on a pipeline-by-pipeline basis due to the interconnected and dependent nature of some of the pipelines to each other. Thus, the impacts to capacity on each individual pipeline would be the same as the sub-system. As such, FEI has described the capacity challenges with the PRS alternative at the sub-system level: Exhibit B-1, Application, p. 75, fn. 66.

and constrained during the winter when there is high gas demand.[103] In the event of a supply interruption on the Enbridge transmission system north of Kingsvale, which occurred in 2018 following an ignited rupture on the Enbridge NPS 36 natural gas transmission pipeline, FEI would be further limited in its ability to support the resiliency of the CTS.[104]

- **Savona Control Station to Oliver Y Control Station:** The SAV VER 323, VER PEN 323 and PEN OLI 273 transmission pipelines, which make up this sub-system, provide gas to approximately 167,000 existing customers in local communities in the Okanagan region surrounding the pipelines. Even with the proposed Okanagan Capacity Upgrade (OCU) Project in-service, based on current demand, the pressure reduction required to achieve a hoop stress level below 30 percent of SMYS would result in a capacity shortfall reappearing on this sub-system and the inability to maintain reliable customer supply in all but the warmest days of the year.[105]

- **East Kootenay Exchange Control Station Oliver Y Control Station:** The YAH TRA 323, OLI GRF 273 and GRF TRA 273 transmission pipelines, which make up this sub-station, provide gas to approximately 28,000 existing customers in local communities surrounding the pipelines. The pressure reduction required to achieve a hoop stress below 30 percent of SMYS would result in a capacity shortfall on this sub-system and the inability to maintain reliable supply for customers in the Central Kootenay, Castlegar and Nelson regions outside of the summer months, and would be inadequate to meet the needs of current industrial customers in these communities throughout the year.[106]

48. Dynamic Risk similarly identified the potential for PRS to create capacity constraints:[107]

> The installation of a pressure regulating station (PRS) would effectively manage the threat of SCC by reducing the operating pressure below 30% of the SMYS and reduce the potential for rupture. This alternative causes capacity limitations in the pipeline and as noted by FEI, would lead to a significant reduction in the capacity available to customers.

---

103 Exhibit B-7, CEC IR1 20.1.
104 Exhibit B-1, Application, pp. 76-77.
105 In particular, a pressure reduction of this kind would result in pressure supplied at the inlet to the sub-system at Savona and Oliver Y being very close to the minimum pressure needed for the pipeline to deliver into the laterals and gate stations served by the pipeline: Exhibit B-1, Application, p. 78.
106 Exhibit B-1, Application, pp. pp. 78.
107 Exhibit B-1, Application, Appendix O-1, p. 13.

> To meet the demand while operating at reduced pressure the pipeline would require system looping. Utilizing the EMAT ILI tool and having a robust validation program, as outlined in Section E.7, has allowed gas pipeline operators to successfully manage the threat of SCC while operating the pipelines without system wide pressure reduction.

49. Projects to compensate for the capacity reduction resulting from the PRS alternative would be substantial (e.g., pipeline looping, compressor facilities and peak shaving injection), resulting in a project much more costly and more impactful to the environment and communities than the proposed ITS TIMC Project.[108] Operating below 30 percent of SMYS for only part of the year is also not an acceptable project alternative as it does not offer mitigation of cracking when pressure is not limited and, as such, FEI would not meet its regulatory obligations or be in alignment with industry practice during those times.[109]

50. For these reasons, the PRS alternative is not technically feasible for the 8 ITS pipelines.

(c) Alternative 3: HSTP has Significant Operational Challenges

51. The implementation of a hydrostatic testing program (HSTP) to verify the integrity of a transmission pipeline over its lifecycle is a complex process that involves periodically taking the pipeline out of service at recurring intervals and subjecting it to a hydrostatic test over its lifecycle.[110] FEI last re-tested a pipeline using HSTP in 1994.[111] HSTP is not effective as a method for managing cracking threats on operating gas lines as hydrostatic testing does not provide information on cracks that do not fail during the test, but that may nonetheless grow over time, or provide information on the rate of crack growth.[112] As such, there is no way for FEI to predict whether a failure will occur and plan to proactively remove the crack defect prior to the next test interval.[113]

52. HSTP also has the potential to exacerbate sub-critical cracks which FEI cannot monitor.[114] Further, as HSTP is performed on a segment-by-segment basis for each pipeline, there is a risk of capacity challenges where hydrostatic testing cannot be completed on the entirety of the pipeline prior to winter when it needs to be back in service to serve higher demand.[115] This is a particular concern on the ITS due to the long lengths of its pipelines, which range from 30 to 163 kilometres.[116] In the event that a failure

---

108 Exhibit B-7, CEC IR1 19.3.
109 Exhibit B-7, CEC IR1 19.1.
110 Exhibit B-1, Application, pp. 60-61.
111 Exhibit B-8, RCIA IR1 5.2.
112 Exhibit B-1, Application, p. 61.
113 Exhibit B-7, CEC IR1 21.1.
114 Exhibit B-1, Application, pp. 71 and 79.
115 Exhibit B-1, Application, p. 71.
116 Exhibit B-1, Application, p. 79 and fn. 71.

occurred during a test but FEI was unable to test the entirety of a pipeline, FEI may be required to implement a 20 percent pressure reduction to establish a factor of safety for the untested segments of the pipeline. Given the lack of pipeline looping on the ITS, implementing a 20 percent pressure reduction would likely result in a capacity constraint in the relatively near term (i.e., beyond 7 years).[117] The costs, and environmental and societal impacts, associated with this looping component alone would be at least an order of magnitude higher than the proposed cost of the ITS TIMC Project.[118]

53. Finally, FEI also observes that a hydrostatic test failure could result in the release of pressurized water, necessitating the creation of a safe testing zone (in addition to already extensive temporary workspace requirements) and may also require the evacuation of nearby residents.[119]

54. Dynamic Risk reiterated a number of FEI's conclusions regarding the HSTP alternative:[120]

> A hydrostatic testing program (HSTP) involves taking the pipeline out of service, introducing water into the pipeline and pressurizing the line to confirm the integrity. As noted by FEI in the application, hydrotesting is a complex process that involves significant operational, community and environmental challenges in an urban environment. This method is effective to manage the threat of SCC, however, only significant features that are close to leak or rupture (near critical) will be detected and repaired. The hydrotest confirms the integrity of the pipeline but offers no information on the cracks that survived the hydrotest, which can continue to grow under normal operations following the test. The EMAT ILI tool is significantly less disruptive to the operations of the pipeline and provides location and sizing information on both the near critical flaws and sub critical flaws. This allows the operator to repair any near critical features, perform an assessment on the sub critical flaws to plan future excavations and re-inspection intervals.

55. The above-noted operational, community and environmental challenges render HSTP not technically feasible for application to the 8 ITS pipelines.

C. <u>Alternatives 5 and 6: Screened Out as Not Financially Feasible</u>

56. The pipeline replacement (PLR) (Alternative 5) and pipeline exposure and recoat (PLE) (Alternative 6) alternatives contemplate either: (1) replacing the existing pipeline with a new pipeline coated with a high integrity coating that is not conducive to the formation of SCC; or (2) removing the existing coating, inspecting for and repairing any cracking or other anomalies, and then recoating the entire pipeline with

117 Exhibit B-1, Application, pp. 79-80; Exhibit B-7, CEC IR1 21.1.
118 Exhibit B-7, CEC IR1 21.1.
119 Exhibit B-1, Application, pp. 71-72.
120 Exhibit B-1, Application, Appendix O-1, p. 13.

a high integrity coating.[121] While both alternatives are technically feasible and, importantly, are highly effective methods for the mitigation of third-party damage, natural hazards and cracking threats, providing near certainty that no cracking remains on the system after implementation, they would also require complex work to implement on the entirety of the 8 ITS transmission pipelines (totalling approximately 752 kilometres of pipe).[122] This work would present a number of significant implementational challenges[123] in addition to considerable cost.

57. FEI did not consider it to be a prudent use of funds to undertake a cost estimate of the PLR and PLE alternatives for the entirety of the ITS TIMC Project given the relatively high cost of a preliminary Class 5 estimate for a project of this magnitude (between approximately $45 and $60 thousand per estimate).[124] Instead, FEI relies on the comparison of the NPV of the total cost for PLR and PLE to the preferred EMAT ILI alternative undertaken as part of the CTS TIMC proceeding.[125] Without taking into consideration that the 8 ITS pipelines are approximately 3 times longer than the 11 pipelines within the scope of the CTS TIMC Project (which would increase the cost of PLR and PLE), Table 4-4 of the Application demonstrates that the cost of PLR and PLE would be an order of magnitude higher than EMAT ILI.[126] FEI considers the results of the analysis from the CTS TIMC Project to be a reasonable comparator – with a *similar or larger* ratio of costs between EMAT ILI and the PLR and PLE alternatives.[127] As shown in Table 4-5 of the Application, reproduced below, the relative cost of each alternative makes it clear that implementation of PLE and/or PLR on the entire ITS system are cost prohibitive when compared to EMAT ILI.[128]

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

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

58. Ultimately, the extensive scope of the work that would be required to undertake PLR and PLE would result in very high costs, making this alternative cost prohibitive compared to EMAT ILI. This

121 Exhibit B-1, Application, p. 67.
122 Exhibit B-6, BCOAPO IR1 2.2; Exhibit B-9, BCUC IR2 21.1.
123 Exhibit B-1, Application, pp. 71-72.
124 Exhibit B-7, CEC IR1 22.1.
125 Exhibit B-1, Application, p. 81; see also Section 4.5 of the CTS TIMC CPCN Application, Online: https://docs.bcuc.com/Documents/Proceedings/2021/DOC_61095_B-1-FEI-CTS-TIMC-Project-CPCNApplication.pdf.
126 Exhibit B-1, Application, pp. 81.
127 Exhibit B-1, Application, pp. 81-82.
128 Exhibit B-1, Application, p. 82.

conclusion was further endorsed by the BCUC in its decision regarding granting a CPCN for the CTS TIMC Project which described these alternatives as "prohibitively expensive".[129] On this basis, FEI assessed both as being not in the public interest, and thus, not feasible.[130]

D. Alternative 4: EMAT ILI Is the Only Feasible Alternative to Achieve the Project Objective

59. EMAT ILI is an established technology[131] and the only alternative that is both technically and financially feasible. As such, it is the preferred alternative to achieve the Project objective of enhancing FEI's integrity management capabilities to mitigate cracking threats to the 8 ITS transmission pipelines.

60. FEI's proposed EMAT ILI program involves periodically running[132] an ILI tool through a pipeline to detect anomalies or defects, including SCC and sub-critical long seam weld features that would not fail a hydrostatic pressure test. This is achieved using varying magnetic fields to generate and detect sound waves in the steel pipe using specialized sensors and, in particular, detecting when the resulting sound waves are interrupted.[133] FEI intends to use EMAT ILI tools that are propelled using gas flow, like other conventional ILI tools.[134] These runs will assess approximately 36 percent of the ITS for cracking (approximately 752 of 2,072 kilometres), reflecting the current availability of commercialized tools.[135] The technical capabilities of EMAT ILI were explained further by Dynamic Risk as part of the Independent Report.[136]

61. EMAT ILI has been under development for over 25 years,[137] and has been proven to successfully detect crack-like features.[138] Further, when used in conjunction with existing ILI technologies, such as MFL-C, EMAT ILI run data can be used to distinguish between cracking located in the pipe body or seam weld.[139] Overall, this approach is consistent with CSA Z662:19 Clause 10.3.1 and provides an effective method for an operator to "monitor for conditions that can lead to failures" and "to eliminate or mitigate such conditions".[140] Like the two other technically feasible alternatives, EMAT ILI is highly effective at managing

---

129 BCUC Decision and Order C-3-22, p. 19.
130 Exhibit B-1, Application, p. 82; see also Exhibit B-6, BCOAPO IR1 2.3.
131 Exhibit B-1, Application, Appendix O-2, BCUC-Dynamic Risk IR1 5.1 (PDF pp. 9-11).
132 These runs are undertaken based on a pipeline-by-pipeline analysis.
133 Exhibit B-1, Application, pp. 61-62 and fn. 55.
134 Exhibit B-1, Application, p. 62.
135 Exhibit B-6, BCOAPO IR1 1.1.
136 Exhibit B-1, Application, Appendix O-1, p. 15.
137 Exhibit B-4, BCUC IR1 4.1.
138 Exhibit B-7, CEC IR1 15.1.
139 Exhibit B-8, RCIA IR1 3.1.
140 Exhibit B-1, Application, p. 47.

cracking threats. In particular, this technology is capable of identifying, locating and sizing cracking anomalies or defects, with direct measurements subsequently taken through integrity digs to confirm findings.[141] There is extensive evidence on the record that EMAT ILI is the best available technology for mitigating cracking threats on natural gas pipelines. For example, Dynamic Risk states: “The evolution of EMAT technology has allowed for the reliable detection, identification and sizing of crack anomalies and has increasingly provided an effective basis for managing the threat of SCC to an appropriate safety level."[142] These conclusions are also supported by FEI’s peer operators, who are enhancing their approaches to crack management with the adoption of EMAT ILI.[143] The use of EMAT ILI is an active form of integrity management that is rapidly becoming the industry standard for managing cracking threats on transmission pipelines, reflecting the potential for significant consequences should failure occur.[144]

62. In summary, EMAT ILI enables the active and cost-effective monitoring and management of cracking threats as ILI data will be available on an ongoing basis, allowing for the prioritization of mitigation for cracks posing significant threats and predicting the growth of sub-critical cracks to ensure they do not grow to failure.[145] The use of EMAT ILI also minimizes impacts to communities and the environment, due to its minimal excavation requirements and work to ready the ITS for EMAT ILI runs being confined to FEI’s existing rights of way and facilities.[146] Finally, as discussed above with respect to the PLR and PLE alternatives, EMAT ILI is also the only financially feasible alternative.

63. FEI submits that EMAT ILI is clearly the preferred alternative to address the identified cracking threats to the ITS.

PART FOUR: PROJECT DESCRIPTION, COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

64. This Part of this Final Submission addresses the project description, costs, accounting treatment and rate impacts of the ITS TIMC Project.

65. As described in Section 5 of the Application, the ITS TIMC Project consists of the work required to modify pipelines within FEI’s existing rights of way and associated facilities to ready the ITS for EMAT ILI tools. This work includes the replacement of 3 heavy wall segments on two ITS pipelines, which will

---

141 Exhibit B-1, Application, p. 83.
142 Exhibit B-1, Application, Appendix O-1, p. 14.
143 Exhibit B-1, Application, Appendix O-1, p. 31; see also Exhibit B-1, Application, p. 84.
144 Exhibit B-1, Application, p. 84; Exhibit B-6, BCOAPO IR1 1.6.
145 Exhibit B-1, Application, p. 71.
146 Exhibit B-1, Application, p. 72.

eliminate unacceptable speed excursions at these location, as well as alterations to 13 ITS facilities, which will enable EMAT ILI tool runs in the ITS. These alterations consist of modifications to pig barrels and station piping, as well as the addition of pressure regulating and flow control capabilities.[147] FEI has worked with internal subject matter experts and ILI tool vendors to determine what alterations are required on its system to support successful runs of EMAT ILI tools on the 8 ITS pipelines, and the alterations proposed in the Application are the minimum requirements.[148]

66. Upon receiving BCUC approval, FEI plans to initiate the detailed design and procurement activities. Execution of the Project will be subdivided into two phases, completing activities as follows:[149]

- **Phase 1:** Activities on the SAV VER 323 and VER PEN 323 pipeline systems, including pipeline alteration Event 1, as well as facility alterations at Savona Compressor Station, SN-3, SN-4, SN6-1, Salmon Arm Tap, SN-7, and Penticton Gate Station; and

- **Phase 2:** Pipeline alteration Events 29 and 31, as well as facility alterations at Kingsvale Control Station, Princeton Crossover Control Station, Oliver Y Control Station, SN-15, SN-17 and East Kootenay Exchange.

67. FEI has assumed construction will begin in Q2 2025, with Project completion to be completed by the end of 2026, followed by close-out activities in Q1 2027. [150]

68. The total capital cost estimate for the ITS TIMC Project is $84.588 million (as-spent), which includes AFUDC, income tax recovery, contingency and a management reserve.[151] The Project will result in an estimated cumulative delivery rate impact of 0.72 percent by 2028 when all assets and closing costs have entered FEI’s rate base.[152] This compares to a levelized delivery rate impact of 0.54 percent over 70 years.[153] As noted above, FEI expects to complete the construction of the Project in two phases and, therefore, assets related to Phase 1 of the Project will enter FEI’s rate base on January 1, 2026 while the assets related to Phase 2 enter FEI’s rate base on January 1, 2027, with the small amount of remaining

---

147 Exhibit B-1, Application, p. 2.
148 Exhibit B-12, BCOAPO IR2 8.2.
149 Exhibit B-1, Application, Section 5.5 (pp. 98-99).
150 Exhibit B-1, Application, p. 7.
151 AFUDC of $4.513 million and income tax recovery of $0.883 million: Exhibit B-1, Application, p. 110.
152 Exhibit B-1, Application, p. 118.
153 This impact is consistent across a 30-year, 40-year, and 50-year period: Exhibit B-9, BCUC IR2 24.1.

closing costs incurred in 2027 to enter FEI's rate base on January 1, 2028.[154] The average annual delivery rate impact over the five years from 2024 to 2028 is estimated to be 0.14 percent annually or $0.007 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $0.63 per year over the five years, or $3.15 cumulatively by 2028.[155]

69. The evidence supporting the Project scope, cost estimate, schedule and rate impacts analysis is detailed and complete, and demonstrates that FEI has prudently and carefully scoped, planned, and estimated the costs for the Project.

70. In Section 5 of the Application, FEI provided detailed information on the Project, including:

- an overview of the Project and the rationale for performing alterations to the pipelines and their associated facilities in preparation for EMAT ILI runs;
- a description of the compatibility of ITS TIMC Project assets and future hydrogen blending activities;
- a description of the modifications to the pipelines that are necessary for the collection of full resolution ILI data;
- a description of the modifications required to the 13 facilities associated with the 8 ITS pipelines that are necessary to run EMAT ILI tools and to respond to any anomalies found as a result of the in-line inspections;
- a description of the schedule, project resource requirements and management;
- the basis of the cost estimate, and the processes undertaken to validate the estimate including risk assessment and contingency determination; and
- a description of the post-Project work following the completion of alterations described.

71. In Section 6 of the Application, FEI describes the actual and forecast costs in the TIMC Development Cost deferral account, provides a breakdown of the Project costs, summarizes the financial analysis, and details the accounting treatment of capital costs and rate impact of the Project.

---

154 Exhibit B-1, Application, p. 121.
155 Exhibit B-1, Application, p. 121.

72. Sections 5 and 6 of the Application are supported by extensive reports, including: (1) Stantec's Front-End Engineering Design (FEED) reports and documents, the Basis of Schedule and Schedule Report, and the Basis of Estimate and Estimate Report (Confidential Appendix G); (2) JANA's Analysis of Cracking Threats and QRA reports (Confidential Appendix B); (3) a Project Risk Register and Validation Estimating's Contingency and Escalation reports (Confidential Appendix H);[156] (4) the Project schedule (Appendix I);[157] and (5) the financial analysis (Confidential Appendix J).[158]

73. The following sections discuss the topics explored in the proceeding, making the following points:

- FEI has correctly scoped and planned the Project.
- FEI's cost estimate is robust and meets the BCUC's CPCN Guidelines.
- FEI's timeline for the ITS TIMC Project is reasonable and reflects the potentially significant consequences of delay.
- FEI's proposed treatment of the balance of the TIMC Development Cost deferral account balance is just and reasonable.

A. <u>FEI Has Correctly Scoped and Planned the Project</u>

74. The ITS TIMC Project will enable FEI to undertake EMAT ILI tool runs on the ITS by replacing 3 heavy wall segments, which FEI has identified as having a high probability of causing EMAT tool speed excursions, as well as 13 facilities to ready the ITS for EMAT ILI tool runs. While FEI will complete construction of the CTS TIMC Project before this Project, the two projects address the same objective of enhancing FEI's integrity management capabilities to mitigate cracking threats on transmission pipelines it has found to be susceptible to cracking threats.[159] The Project scope includes:

- **The replacement of 3 heavy-wall segments along two pipelines:** These segments of the Savona Vernon 323 (SAV PEN 323) and Kingsvale Princeton 323 (KIN PRI 323) pipelines need to be replaced to ensure the EMAT ILI tool travels within its optimal velocity range at these 3 locations, thereby preventing speed excursions. Analysis of ILI velocity data from previous inspection runs, coupled with a review of EMAT ILI tool specifications and

156 Exhibit B-1-1, Confidential Application.
157 Exhibit B-1, Application.
158 Exhibit B-1-1, Confidential Application.
159 Exhibit B-7, CEC IR1 7.1.

discussions with ILI tool vendors, revealed that speed excursions frequently happen downstream of heavy-wall portions of pipe.[160]

- **The alteration of 13 facilities:** These alterations will enable the introduction of EMAT ILI tools on the ITS and include: (i) pig barrel modifications to accommodate EMAT ILI tools;[161] (ii) the installation of gas flow control capability to manage tool velocity;[162] (iii) the installation of pressure regulation capability in two locations;[163] and (iv) the modification to control and safety systems.[164]

75. The modifications above are described further in Sections 5.3, 5.4 and Appendix G-1 (Final FEED Report (M-0002-PMT-REP-0028)) of the Application. While FEI has been running geometry, MFL-A, and MFL-C tools in ITS pipelines for many years, EMAT ILI tools have a different set of system readiness criteria, as provided in Appendix F-1 to the Application, necessitating the proposed modifications to the ITS.[165]

76. The proposed scope of the ITS TIMC Project was the subject of several IRs and intervener evidence, which FEI addresses below. The evidence FEI has provided as part of this proceeding supports the following points:

- Pressure reduction capabilities provide an industry-accepted level of risk mitigation and other operational benefits.
- The proactive replacement of the three heavy-wall segments is cost-effective and prudent.
- Speed control is not yet available for NPS 10 and 12 pipe diameters and, while able to provide several benefits for tool performance, does not eliminate the risk of data loss from speed excursions.

---

160 Exhibit B-1, Application, Section 5.3 (pp. 89-92).
161 Exhibit B-1, Application, pp. 93-94.
162 Exhibit B-1, Application, pp. 94-95. FEI has proposed installing flow control at the following stations: (1) SN-7 (Vernon); (2) Penticton Gate Station; (3) Princeton Crossover Control Station; and (4) SN-15 (Grand Forks).
163 Exhibit B-1, Application, pp. 95-96. FEI has proposed installing pressure regulating capabilities at the following stations: (1) East Kootenay Exchange Station; and (2) SN-4 Valve Assembly.
164 Exhibit B-1, Application, pp. 96-98.
165 Exhibit B-1, Application, p. 86 and Appendix F.

(a) Pressure Reduction Capabilities Are Needed and Provide a Reasonable and Industry-Accepted Level of Risk Mitigation

77. As outlined in Section 5.4.4 of the Application, FEI must consider and be ready to implement operational changes to safeguard the ITS by reducing the pressure on pipelines where cracking is identified.[166] FEI cannot know how many features will be found on any of the 8 ITS pipelines, or how many of those features will need to be addressed, until after each of their respective baseline EMAT ILI runs and resulting data analysis is complete.[167] As affirmed by Dynamic Risk as part of the CTS TIMC CPCN proceeding, “large variability can be found in the number of anomalies reported by EMAT survey” and, therefore, it is possible that the number of features identified by the EMAT ILI on the lengthy ITS pipelines could exceed FEI’s ability to complete the necessary integrity digs and repairs prior to winter.[168]

78. Pressure reduction capabilities provide FEI with additional operational and maintenance flexibility to implement a safe operating pressure when FEI finds cracking that needs to be addressed on the ITS following EMAT ILI runs. Specifically, the installation of a PRS enables FEI to implement a pressure reduction of 20 percent of the Established Operating Pressure (EOP),[169] which is reasonable and accepted industry standard practice, until the underlying threat is addressed.[170]

79. FEI has reduced the pressure on its ITS pipelines in the past[171] and while FEI is currently able to control pipeline pressures on the ITS at ten control facilities,[172] the following two facilities do not currently have pressure reduction capabilities that meet the Project objectives: (1) East Kootenay Exchange Station (Yahk Station); and (2) SN-4 Valve Assembly. These PRS will expand FEI’s operational and maintenance capabilities to respond to cracking found during baseline or subsequent EMAT ILI runs on the associated pipelines.[173]

80. FEI addresses the following points below:

---

166 Exhibit B-1, Application, p. 95.
167 Exhibit B-18-1, Rebuttal Evidence, A6.
168 Exhibit B-8, RCIA IR1 13.6.
169 FEI defines EOP as “The pressure that is intended to reflect the recent historical trend of pipeline operating pressure due to supply and demand factors. The EOP is the higher of: (1) the pressure below which the pipeline operated 99.5% of the time over the last 18 months, or (2) the highest pressure over a continuous 8-hour period within the last 18 months.”: Exhibit B-19, BCUC IR3 29.1.
170 Exhibit B-1, Application, pp. 95-96.
171 Exhibit B-18-1, RCIA IR1 13.4.
172 See Exhibit B-1, Application, Table 5-5 (pp. 97-98) for a list of these control stations.
173 Exhibit B-1, Application, p. 96.

- Proactively installing pressure reduction capabilities aligns with FEI's statutory and regulatory obligations, as well as standard industry practice.
- FEI requires independent pressure control at the Yahk Station.
- It is not feasible to defer the installation of the proposed PRS at the Yahk Station.
- A temporary PRS at the SN-4 Station enables FEI to maintain capacity in the event it is required to reduce pressure on the Savona to Penticton 323 mainline.

Proactive Installation of Pressure Reduction Capability is Consistent with Statutory and Regulatory Obligations and Standard Industry Practice

81. Operators establish the capability for pressure reductions proactively as, when the need for pressure reduction arises, timeliness of response can be important. While the method by which an operator achieves this capability may vary, establishing pressure reduction capability is standard industry practice.[174] In particular, it is industry standard practice to reduce the operating pressure in a pipeline while conducting an integrity-related excavation or in response to integrity concerns identified through an ILI run.[175] As set out in CSA Z662-19:[176]

> <u>Section 10.10.1.4</u>
>
> Excavation of piping suspected of containing defects and if required, the subsequent permanent or temporary repair of such piping shall be performed after the piping is depressurized as necessary to an operating pressure that is considered to be safe for the proposed work.
>
> <u>Section 10.10.1.5</u>
>
> Where piping is not suitable for continued service at the established operating pressure due to the presence of defects, either the piping shall be operated at pressures that are determined by an engineering assessment to be acceptable or the affected piping shall be repaired as specified in Clauses 10.10.2 to 10.12.

82. Depending on the number and characteristics of the defects discovered during an EMAT ILI tool run, FEI may be required to operate the affected pipeline at reduced pressures for extended periods of time as it may be unable to excavate, inspect and if necessary, remediate, indications provided in the vendor ILI report.[177] A pressure reduction to 80 percent EOP would be a typical approach to providing a

---

174 Exhibit B-8, RCIA IR1 13.3.
175 Exhibit B-8, RCIA IR1 13.3; see also Exhibit B-1, Application, Appendix F, p. 7.
176 Exhibit B-1, Application, Appendix F, p. 7.
177 Exhibit B-8, RCIA IR1 13.7.

safety factor for the pipeline until such time as the particular cracking was repaired.[178] When considering the need to operate the pipeline at a reduced pressure to establish a safety factor over potentially injurious cracking, FEI must be able to confidently maintain that pressure across the entire pipeline and avoid any overpressure events that could lead to failure of the crack.[179]

83. As explained above, to provide pressure reduction capability, FEI will leverage the existing control points in the ITS, as well as installing two new PRS where current pressure control capabilities are insufficient.

FEI Requires Independent Pressure Control at the Yahk Station

84. FEI needs to install the proposed PRS at the Yahk Station to support its EMAT ILI activities on the YAH TRA 323 pipeline planned for 2030[180] and, if cracking is found, to ensure that pressure on the pipeline can be controlled in a timely manner not to exceed 80 percent of the EOP anywhere on the pipeline.[181]

85. While the Yahk Station currently has pressure reduction capabilities, the utility of these capabilities in the context of mitigating the risk of cracking is limited due to the existing single control valve configuration.[182]

---

178 Exhibit B-19, BCUC IR3 29.2.

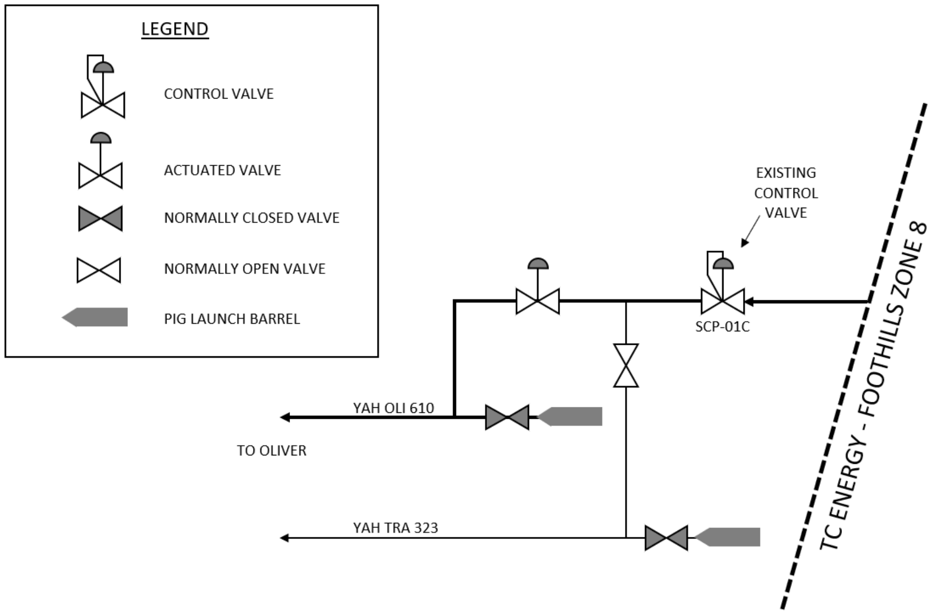
179 Exhibit B-19, BCUC IR3 29.3.

180 FEI may undertake the initial EMAT ILI run earlier than 2030 if possible, depending on the results of earlier scheduled initial EMAT inspections: Exhibit B-4, BCUC IR1 29.4 and Exhibit B-19, BCUC IR3 29.4.

181 Exhibit B-19, BCUC IR3 29.3.

182 Exhibit B-18-1, Rebuttal Evidence, A12.

Figure 1: Configuration of Existing Control Valve at Yahk Station



86. The YAH TRA 323 pipeline has a maximum operating pressure of 7,136 kPa and can flow gas bi-directionally. For most of the year, FEI flows gas east to west, receiving gas from TC Energy at a minimum contractual delivery pressure of 5,171 kPa and feeding communities as far west as Osoyoos, depending on the time of year.[183] As shown in the schematic above, gas flows from TC Energy through the existing control valve (SCP-01C), after which the gas is fed to both the YAH OLI 610 and YAH TRA 323 pipelines. The limitations of this single control valve will adversely impact FEI's ability to implement a pressure reduction on the YAH TRA 323 pipeline, while also reducing FEI's operational flexibility and increasing costs.[184] FEI outlines the drawbacks of this limitation, and corollary need for this PRS, below.

87. First, the existing single control valve only allows FEI to simultaneously reduce the pressure on the YAH OLI 610 and YAH TRA 323 pipelines. As a result, if FEI were required to reduce the pressure on the YAH TRA 323 pipeline by up to 20 percent EOP, it would also be forced to unnecessarily restrict pressure on the YAH OLI 610 pipeline, which compromise FEI's ability to deliver the needed maximum load of 105 MMSCFD to the CTS. As FEI explained in its Rebuttal Evidence:[185]

---

183 As discussed in the response to BCUC IR3 29.4.1 (Exhibit B-19), FEI does not anticipate that the operating pressure of the YAH TRA 323 pipeline will be at or below 80 percent of the pipeline's current established operating pressure by the date of the initial EMAT ILI run.

184 Exhibit B-11, RCIA IR2 23.1.

185 Exhibit B-18-1, Rebuttal Evidence, A12.

> FEI relies upon the maximum load of 105 MMSCFD as part of the total supply required for the CTS and other communities between Kingsvale and Huntingdon (particularly during winter), as well as to respond to unexpected circumstances in off-peak seasons (e.g., minor supply reductions on the T-South system upstream of Kingsvale). If a pressure reduction were to occur on the YAH OLI 610 pipeline during Winter 2030/31, following the EMAT ILI tool run on the YAH TRA 323 pipeline, FEI would only be able to supply a maximum of 68 MMSCFD to the CTS on a Design Degree Day (i.e., a reduction of 37 MMSCFD in capacity).

As such, in peak winter conditions, if the YAH OLI 610 is operated with a pressure reduction, FEI would not be capable of delivering the gas projected to be needed to the Oliver Control Station to support demand in the Okanagan or delivering gas to Kingsvale (and via Enbridge's pipeline) to support customers in the Lower Mainland.[186]

88. Second, the installation of independent pressure control at the Yahk Station will provide FEI with improved operability, reliability and resiliency over the long-term:[187]

- If FEI is required to expose the YAH TRA 323 pipeline for any reason, including to complete integrity digs and/or pipeline repairs resulting from any ILI run, it is standard procedure to temporarily reduce the operating pressure of the pipeline to perform the work safely. Since a pressure reduction also limits pressure on the YAH OLI 610 pipeline, FEI's flexibility to perform work on the YAH TRA 323 pipeline is limited at times by the need for capacity on the YAH OLI 610 pipeline. Having independent pressure control on each line will allow for more flexibility in timing to complete integrity work and improve FEI's ongoing capabilities to collect and respond to integrity data.[188]

- Maintaining capacity on the YAH OLI 610 pipeline in a reduced pressure scenario would require operating gas-fired compressor stations during off-peak times. This would result in higher O&M costs and increased greenhouse gas emissions due to both the added run time and potential inefficient operation of the compressors under this type of operating scenario.[189]

[186] Exhibit B-8, RCIA IR1 13.1.
[187] Exhibit B-18-1, Rebuttal Evidence, A12; Exhibit B-19, BCUC IR3 28.1.
[188] Exhibit B-18-1, Rebuttal Evidence, A12.
[189] Exhibit B-18-1, Rebuttal Evidence, A12.

- FEI has provided a description of actual recent events to illustrate how pressure reduction capability is valued and has been used for both in-line inspected and non-in-line inspected pipelines to achieve safe operation.[190]

89. The improved operational and reliability benefits will be particularly beneficial as FEI expects that it may need to reduce the operating pressure of the YAH TRA 323 for longer periods than has previously been needed. FEI is aware through its discussions with peer pipeline operators that initial EMAT ILI tool runs can result in a significant number of cracking indications that require timely inspection and validation. Until these indications are excavated and inspected, FEI must treat them as an integrity risk.[191] Therefore, if severe cracking is indicated through the EMAT ILI run or subsequent data analysis, and FEI is unable to repair these cracking features prior to winter, it would need to sustain a pressure reduction through the winter.[192]

90. With potentially longer pressure reductions on the YAH TRA 323 pipeline, there will be increasing and unnecessary capacity impacts to the YAH OLI 610 pipeline each year if the existing pressure control regime is used. The ability to independently control pressure will allow FEI more flexibility to schedule and complete necessary work on the YAH TRA 323 pipeline, while maintaining its existing service reliability and resiliency with the YAH OLI 610 pipeline.[193]

It is Not Feasible to Defer the Installation of a PRS at the Yahk Station

91. RCIA's proposal that FEI defer determining whether to install the PRS at the Yahk Station until after it has received feedback from the EMAT ILI vendor, in the hopes that FEI would not need the PRS at all, is neither feasible nor prudent.[194] Due to the timing restrictions and other factors set out below, FEI would not be able to wait until after it has received feedback from the EMAT ILI vendor to determine whether to install the PRS:

- **Operational Conditions Limit FEI's Ability to Conduct EMAT Tool Run:** FEI can only be able to undertake ILI tool runs between March and October due to operational conditions during colder months (i.e., November to February). In particular, in addition to the impact of inclement weather on working conditions and accessing the remote area in which the

---

190 Exhibit B-18-1, Rebuttal Evidence, A15, pp. 11-23.
191 Exhibit B-18-1, Rebuttal Evidence, A14.
192 Exhibit B-18-1, Rebuttal Evidence, A14.
193 Exhibit B-18-1, Rebuttal Evidence, A14.
194 Exhibit C2-6.

pipeline is located, the system operating configuration required to achieve target EMAT ILI tool velocities (1-2 m/s) results in the inability to supply gas to the CTS during these colder months.[195] Moreover, in the past 10 years, FEI has only performed tool runs on this pipeline between April and May.[196] This significantly restricts the times at which FEI would receive feedback from the EMAT ILI vendor.

- **FEI Lacks Certainty Regarding Timing for the ILI Vendor to Provide Preliminary Findings:** FEI has estimated a vendor reporting timeframe of up to 180 days (6 months) for EMAT ILI runs on the CTS.[197] This estimate is based on information provided by vendors, which aligns with informal information from FEI's peer transmission pipeline operating companies, and FEI's understanding that the vendor's analysis to identify and size cracking after an EMAT ILI run is generally more involved than the analysis for other ILI tools. While the vendor may deliver preliminary findings sooner, FEI cannot rely on this occurring as ILI vendors provide preliminary findings on a "best efforts" basis and do not provide FEI with any certainty around the time it will be able to deliver its preliminary findings. Further, by the time of the first EMAT ILI runs on the ITS, vendor reporting timeframes could be even longer due to vendor capacity becoming increasingly constrained.[198]

- **FEI Requires Time to Undertake an Initial Review of the Vendor's Preliminary Findings:** Once FEI has received the vendor's preliminary report, it must undertake its own initial review of the vendor's initial report and identify potentially injurious cracking on the pipeline requiring a pressure reduction. While these activities will continue for more than 2 months after it receives the preliminary report, FEI estimates that it will generally take approximately 30 to 60 days (1 to 2 months) to identify potentially severe cracking.[199] This process involves, in particular: (i) validating the accuracy of the vendor reporting; (ii) reviewing any crack-like features for their failure potential, including by completing integrity digs and analyzing findings; and (iii) evaluating whether identified cracking

---

[195] Exhibit B-20, BCOAPO IR3 13.1 and Exhibit B-18-1, A11.
[196] Exhibit B-18-1, Rebuttal Evidence, A11.
[197] In particular, more human intervention and interpretation is generally required before results are provided: Exhibit B-18-1, Rebuttal Evidence, A5; Exhibit B-22, RCIA IR3 26.3.
[198] Exhibit B-18-1, Rebuttal Evidence, A5.
[199] Exhibit B-20, BCOAPO IR3 13.1.

interacts with other ILI tool findings (e.g., corrosion). This process may identify cracking requiring a pressure reduction that was not previously identified by the vendor.[200]

- **Delayed Decision to Install PRS Increases Installation Time:** It will take more time to install a PRS at the Yahk Station on short notice (after FEI's review of the vendor's preliminary results), than proactively installing the PRS as proposed in the Application. In particular, FEI would need to coordinate and mobilize resources to the station before it can install the bypass, yard piping and complete the PRS tie-in. FEI estimates that this process would take approximately 60 days (including installation).[201] This contrasts with the 35 day installation period where the PRS installation is installed as proposed in the Application.[202] While FEI expects that it could save some time (approximately 15 days) by diverting internal integrity dig resources, this approach would adversely impact the number of integrity digs and repairs FEI could complete on the YAH TRA 323 pipeline.[203] Further, delaying installation of the PRS to as late as possible in the year, but before the winter, would leave the installation work at risk of events outside of FEI's control (e.g., extreme weather events).[204] If this were to occur, FEI may be unable to install the PRS to meet its timeline and, therefore, would be forced to reduce the pressure on both the YAH OLI 610 and YAH TRA 323 pipelines.[205]

- **Delayed Decision to Install PRS Will Increase Project Costs:** FEI estimates that the cost of installing a PRS at the Yahk Station is approximately $3.782 million. A second mobilization and demobilization of workers to install the PRS after crews have already completed other work at the station, as well as other incremental costs, will increase the total cost of this component of the Project.[206] Further, if the PRS were delayed until after the baseline EMAT ILI run and, ultimately, not needed to reduce the pressure on the YAH TRA 323 pipeline based on favourable cracking integrity results, FEI's would have incurred approximately $1.81 million to procure and fabricate the PRS with no added benefit to the system (assuming $1.363 million in construction labour savings and $0.607 million in

---

[200] Exhibit B-18-1, Rebuttal Evidence, A7.
[201] Exhibit B-18-1, Rebuttal Evidence, A9.
[202] Exhibit B-11, RCIA IR2 23.1.
[203] Exhibit B-18-1, Rebuttal Evidence, A9; see also Exhibit B-20, BCOAPO IR3 13.1.
[204] Exhibit B-18-1, Rebuttal Evidence, A9 and A11.
[205] Exhibit B-18-1, Rebuttal Evidence, A9.
[206] For example, FEI estimates that a second mobilization and demobilization of crews to Yahk Station to install the PRS will cost an additional $67,000: Exhibit B-18, Rebuttal Evidence, A13.

salvage costs).[207] The multiple benefits of the PRS outweigh this avoidable cost being borne by FEI's customers.

92. Given these factors, Table 1 from FEI's Rebuttal Evidence (reproduced below) shows how there is no feasible timeline to install the proposed PRS at Yahk Station if FEI waited until after completing the EMAT ILI run.[208]

Table 1: Timeline and Feasibility of YAHK Station PRS Installation

Tool Run Red – Not feasible due to operational conditions Orange – Potentially feasible with operational conditions Green – Feasible with operational conditions	Vendor Identifies Cracking and FEI Determines a Pressure Reduction is Required		FEI Identifies Cracking and FEI Determines a Pressure Reduction is Required		PRS is Operational Red – Not feasible due to weather conditions Orange – Potentially feasible with weather conditions Green – Feasible with weather conditions		Feasible?
	Earliest (4 mo. after EMAT run)	Latest (6 mo. after EMAT run)	Earliest (1 mo. after vendor earliest)	Latest (2 mo. after vendor latest)	Earliest (2 mo. after vendor earliest)	Latest (2 mo. after FEI latest)	
Jan							No
Feb							No
Mar	Jul	Sept	Aug	Nov	Sept	Jan	No
Apr	Aug	Oct	Sept	Dec	Oct	Feb	No
May	Sept	Nov	Oct	Jan	Nov	Mar	No
Jun	Oct	Dec	Nov	Feb	Dec	Apr	No
Jul	Nov	Jan	Dec	Mar	Jan	May	No
Aug	Dec	Feb	Jan	Apr	Feb	Jun	No
Sept	Jan	Mar	Feb	May	Mar	Jul	No
Oct	Feb	Apr	Mar	Jun	Apr	Aug	No
Nov							No
Dec							No

93. As supported by the considerations and the timeline reproduced above, FEI submits that it is not feasible to defer installation of pressure regulating equipment at the Yahk Station. In particular, waiting to install the equipment until after FEI has received the preliminary feedback from the EMAT ILI vendor is unlikely to afford sufficient time for it to coordinate and install the pressure regulating equipment. Ultimately, it would be imprudent for FEI to defer this PRS as the utility would be left to rely on favourable timelines materializing, while potentially unnecessarily impacting the YAH 11 OLI 610 pipeline over the winter if it cannot get the PRS in-service before winter.

[207] Exhibit B-8, RCIA IR1 16.2; Exhibit B-11, RCIA IR2 23.2 and 23.3.

[208] Exhibit B-18-1.

Temporary PRS at SN-4 Station Enables FEI to Maintain Capacity in the Event of a Pressure Reduction

94. The proposed temporary PRS at the SN-4 Valve Assembly supports pressure control on the SAV VER 323 pipeline. FEI has existing pressure control capabilities on the SAV VER 323 pipeline that allow for operational and maintenance flexibility. However, due to the existing capacity constraints on the Savona to Penticton 323 mainline,[209] FEI cannot implement a pressure reduction on this mainline using these existing control points. As such, FEI has developed an operational strategy to implement and manage a potential pressure reduction following the baseline EMAT ILI run on the SAV VER 323, which is planned for 2026.[210] As FEI has assumed that the OCU Project, or an equivalent capacity improvement, will be installed and in-service by the next EMAT inspection interval, this PRS will not be needed on a permanent basis.[211] This approach will result in approximately $340 thousand in cost savings when compared to constructing a new PRS, and reflects the outcome of FEI's consideration of three different PRS alternatives for this station.[212]

(b) The Replacement of Three Heavy Wall Segments is Cost-Effective and Prudent

95. In assessing the 8 ITS transmission pressure pipelines that are susceptible to cracking threats, and for which EMAT ILI tools are available, FEI conservatively refined the Project scope[213] and determined that alterations are required to replace 3 of 65 heavy wall segments where previous MFL ILI tool runs exhibited speed excursions, one on the SAV VER 323 pipeline (Event 1) and two on the KIN PRI 323 pipeline (Events 29 and 31), before undertaking baseline EMAT ILI tool runs. As explained further below, FEI has high confidence that proactively modifying these three heavy-wall segments is warranted. In particular, replacing these heavy-wall segment will mitigate the risk of blinds spots at these locations, assisting FEI to obtain full coverage of these pipelines for crack mitigation and is, ultimately, cost-effective and prudent.[214]

---

209 The Savona to Penticton 323 mainline is comprised of the SAV VER 323 and VER PEN 323 transmission pipelines.

210 Please refer to the response to BCUC IR1 1.2.1 which outlines FEI's proposed operational strategy: Exhibit B-4, BCUC IR1 1.2.1.

211 Exhibit B-8, RCIA IR1 13.5. Please note that it if the OCU Project is placed in-service prior to winter 2026, the temporary SN-4 PRS may not be needed and, as a result, could be removed from the Project scope and, potentially saving $1,528,000 in construction labour costs: Exhibit B-11, RCIA IR2 23.4 and 23.5.

212 Exhibit B-8, RCIA IR1 13.5.2.

213 Exhibit B-18-1, Rebuttal Evidence, A26.

214 Exhibit B-4, BCUC IR1 8.5.

Heavy-Wall Segments Contribute to EMAT ILI Speed Excursions and Data Loss

96. Heavy-wall segments always present a risk to achieving acceptable EMAT ILI tool runs by changing the velocity ILI tools travel. This change in tool velocity frequently leads to a speed excursion (i.e., where the tool travels outside its optimal velocity range).[215] The effect of speed excursion ranges from degradation of data quality to a complete inability for the tool to collect data, resulting in data collection "blind spots".[216] EMAT ILI tools are more sensitive to speed than other ILI tools with a typical optimal velocity range of 1-2 m/s, and a degraded specification[217] range of between > 2 m/s and < 5 m/s and a maximum velocity for data collection of 5 m/s.[218] As explained by Dynamic Risk as part of the CTS TIMC CPCN proceeding:[219]

> The noise levels in the data will increase gradually but with significant variability, as the tool begins to travel outside the optimum velocity range. Noise levels in the data due to overspeed are analyzed by the vendor on a case-by-case basis to determine if the stated performance specifications can be met or if a reduced specification applies.
>
> Although the data in overspeed areas can be analyzed, the minimum detection length of features detected will always be impacted. The optimum tool velocity for EMAT is less than 2 m/s; velocity levels between 2 and 5 m/s will result in degraded data as the minimum detection length of features will be affected. In some cases, at approximately 5 m/s the data exceeds analysis limits. The negative impact on performance specifications associated with overspeed increases the potential for a false negative (missed crack feature). To effectively manage the SCC threat, the overspeed areas need to be considered as blind spots potentially requiring excavation, ("in-ditch inspection of EMAT ILI tool blind spots")

Replacing heavy-wall pipe to match the wall thickness of adjacent line pipe ensures that EMAT ILI tools do not encounter a transition in pipe wall thickness during inspection, thus avoiding speed excursions and reducing the lengths of pipe where unusable data is obtained.[220] In the absence of addressing the underlying cause of a speed excursion, simply repeating the same ILI run would produce a significantly similar result.[221]

---

215 Exhibit B-7, CEC IR1 24.1.
216 Exhibit B-1, Application, p. 90.
217 Where data is degraded, and a degraded data specification is available, the data can be relied on for integrity management decision-making.
218 Exhibit B-11, RCIA IR2 19.1; see also Exhibit B-1, Application, Appendix F, p. 5.
219 Exhibit B-1, Application, Appendix O-2, BCUC-Dynamic Risk IR1 3.1.1.
220 Exhibit B-1, Application, p. 91.
221 Exhibit B-7, CEC IR1 24.3.

97. FEI included the criteria and metrics which define an acceptable EMAT ILI tool run in the Application and provided additional information in response to IRs from the BCUC.[222] Please also refer to FEI's System Readiness Criteria (Appendix F to the Application) for more information regarding maintaining the optimal EMAT ILI tool velocity on the ITS.[223]

98. While FEI does not require 100 percent successful data capture for an ILI, it does require 100 percent coverage of its pipelines for crack mitigation.[224] Where EMAT ILI data is not captured due to a speed excursion, FEI will not know if or where cracking is located within affected pipeline segments, thus requiring the utility to undertake a site-specific assessment. In the response to BCUC IR1 8.4, FEI provided an overview of the steps it takes where a speed excursion is identified.[225] As part of these steps, and to ensure full coverage of the pipeline, FEI will implement the most cost-effective and technically feasible approach by either: (1) completing heavy-wall replacements and re-running the EMAT ILI tool to obtain usable data; or (2) using an alternate method to mitigate cracking on pipe impacted by the speed excursion (i.e., PLE or PLR).[226] In order to mitigate the risk created by obtaining unusable data, FEI and 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 replacing heavy-wall segments.[227]

The Replacement of Three Heavy Wall Segments on SAV VER 323 and KIN PRI 323 is Warranted

99. As explained in Appendix D to the Application, the results of the EMAT ILI pilot project informed the development and planning of the ITS TIMC Project and, in particular, confirmed that the MFL-C and EMAT ILI tools behave similarly when encountering the same features.[228] Dynamic Risk accepted FEI's approach as part of the CTS TIMC proceeding.[229] FEI leveraged the similar tool behaviours between MFL-C and EMAT ILI to identify where speed excursions were likely to occur on pipelines where EMAT ILI data was not available and, in particular, determined which heavy-wall segments warranted required proactive replacement to ensure usable data is obtained.[230] As part of this assessment FEI considered:[231]

222 Exhibit B-4, BCUC IR1 9 series.
223 Exhibit B-1, Application.
224 Exhibit B-16, RCIA IR2 Clarification 21.2.1.
225 Exhibit B-4.
226 Exhibit B-9, BCUC IR2 20.4; Exhibit B-11, RCIA IR2 20.1.
227 Exhibit B-4, BCUC IR1 8.6.
228 Exhibit B-1, Application, pp. 90-91 and Appendix D, pp. 5-6.
229 Exhibit B-1, Application, Appendix O-2, BCUC IR1 1.3.
230 Exhibit B-1, Application, Appendix D, pp. 5-6.
231 Exhibit B-4, BCUC IR1 8.5.

- **The severity of the speed excursion observed in the MFL-C tool:** The MFL-C tool exceeded the maximum velocity for data collection, meaning there were areas where reliable data was not collected; 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.

100. Using this assessment FEI identified 3 heavy-wall pipe segments warranting proactive replacement (Events 1, 29 and 31). FEI also identified 62 other speed excursion events, affecting 2,867 metres of pipe,[232] where: (1) the velocity of the MFL-C tool typically did not exceed its maximum velocity for data collection (i.e., the data collected may be usable if a degraded data specification is available from the ILI vendor); and (2) the length of pipe affected by each speed excursion event was relatively short such that it may be more cost-effective to directly inspect and mitigate cracking on the affected pipe following the EMAT ILI run, if required.[233] Based on these considerations, and because it does not have a high confidence that a speed excursion will occur, FEI determined that it was prudent to defer deciding whether to replace these heavy wall segments until *after* a baseline EMAT ILI run is completed.[234] If the EMAT tool exhibits a speed excursion during the baseline EMAT run at one of these locations, FEI will evaluate the method that will be applied to mitigate cracking threats on a case-by-case basis.[235]

101. The figure below shows the location of each of the 3 heavy-wall pipe segments within the scope of the ITS TIMC Project:[236]

---

232 Exhibit B-1, Application, Appendix D, p. 7.

233 Exhibit B-8, RCIA IR1 11.4. Further, as explained in the responses to BCUC IR2 20.6 and 20.7 (Exhibit B-9), FEI's selection of proactive heavy-wall pipe replacements is not based on the total length of pipe affected by speed excursions or on a minimum target length of pipeline with speed excursions.

234 Exhibit B-8, RCIA IR1 11.2.

235 Exhibit B-4, BCUC IR1 8.2.1.

236 Exhibit B-1, Application, Figure 5-1 (p. 89).

Figure 5-1: Project Overview Map Showing Pipeline Alternation Locations

FEI weighed the scope associated with proactive pipeline replacement against the scope associated with exposing, inspecting and recoating the pipeline (PLE) or replacing the pipeline (PLR) after the EMAT ILI tool run – ultimately determining that pursuing these heavy-wall pipe replacements will be less costly and disruptive (impactful) than reactive mitigation.[237] In all cases, the length of each heavy-wall replacement was significantly shorter than the length of downstream pipe impacted by a speed excursion.[238]

102. There are, therefore, a number of benefits to proactively modifying the heavy-wall pipe segments at these three locations, including: (1) early mitigation of cracking resulting from collection of high-quality EMAT data during the initial tool run; (2) ongoing collection of high-quality data by EMAT ILI and other in-line inspection tools that allow for monitoring of pipeline integrity; and (3) cost savings.[239]

103. FEI submits that the benefits of proactive replacement outweigh the associated risk of performing unnecessary work. FEI addresses Events 1, 29 and 31 in turn below.

<u>Event 1 (SAV VER 323)</u>

104. Event 1 is located on the SAV VER 323 pipeline in the community of Savona, BC between Savona Compressor Station and the SN-4 Valve Assembly. The heavy-wall pipe was installed after the original crossing was exposed due to erosion during the freshet in 2010 and crosses Cherry Creek.[240] The event

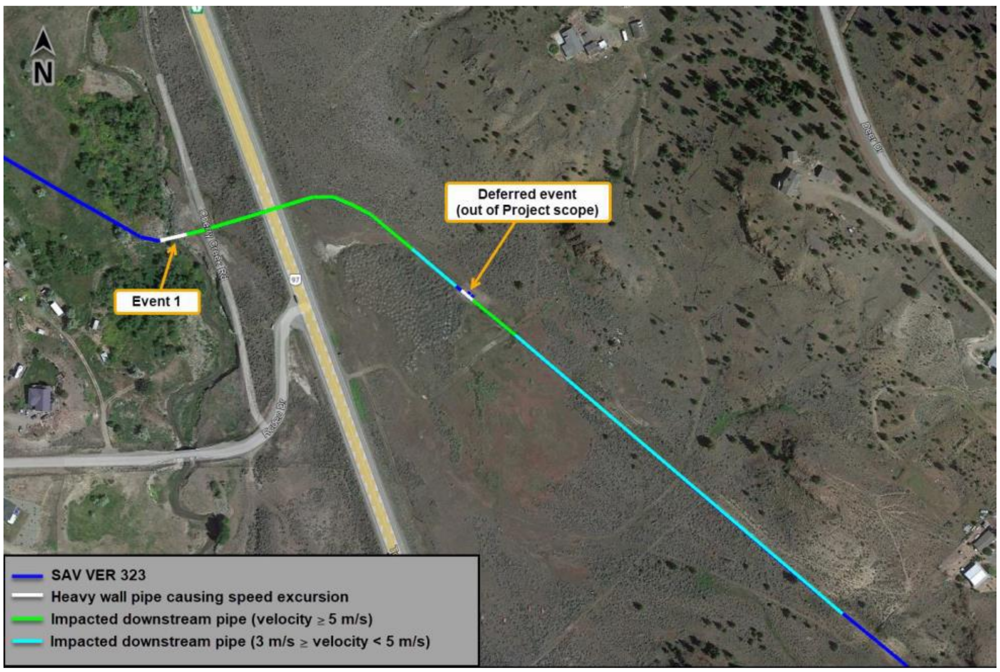
---

[237] Exhibit B-9, BCUC IR2 20.8.
[238] Exhibit B-9, BCUC IR2 20.4.
[239] Exhibit B-4, BCUC IR1 8.2.
[240] Exhibit B-1, Application, p. 91.

falls within the section of the SAV VER 323 pipeline that FEI must operate without a pressure reduction in the winter of the baseline run year to maintain capacity to continue serving customers in the area.[241]

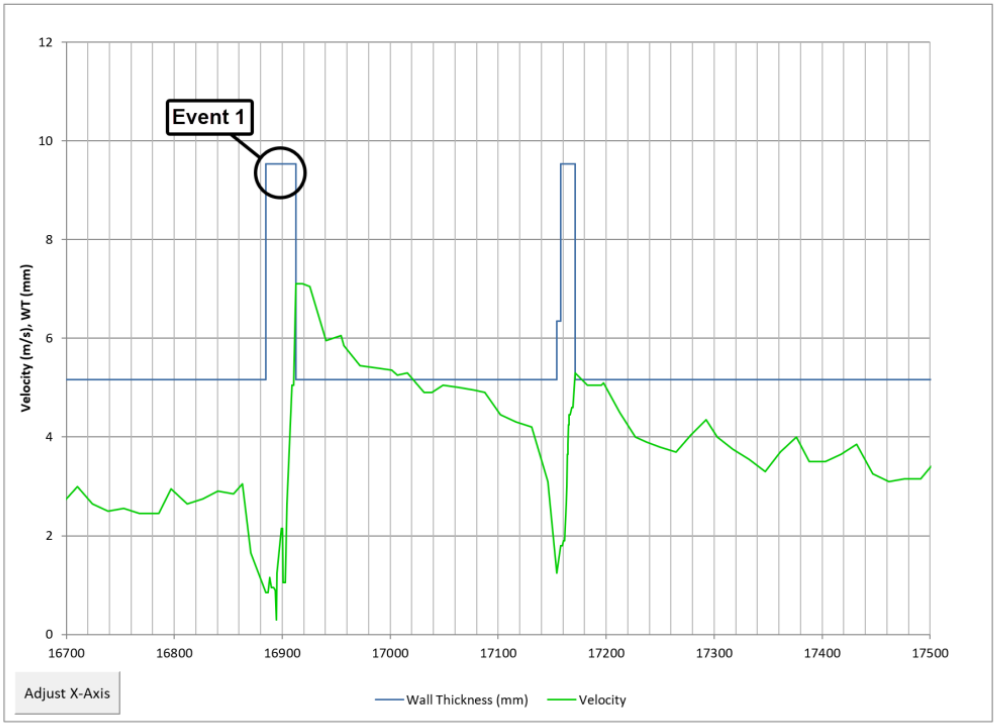
105. As shown in the figures below, the MFL-C tool run at this location travelled above the typical optimal velocity range for 193 metres after the heavy-wall pipe, including a section shortly after the heavy-wall pipe where the tool traveled above the typical MFL-C maximum velocity for data collection.[242]

Figure 2: Event 1 Heavy Wall Pipe and Speed Excursion



---

241 Exhibit B-18-1, Rebuttal Evidence, A16.
242 Exhibit B-18-1, Rebuttal Evidence, A16.



106. By proactively replacing the Event 1 heavy-wall pipe, FEI can avoid more expensive and time-consuming alternatives.[243] In particular, if FEI were required to perform cracking mitigation after the EMAT ILI tool run, FEI would need to proceed with planning and preparing for a trenchless crossing of the Trans-Canada Highway to avoid lengthy expose and recoat work within the highway. The remainder of the pipeline could either be exposed and recoated (PLE) or replaced (PLR).[244]

Events 29 and 31 (KIN PRI 323)

107. Event 29 event was caused by two short heavy-wall pipe segments of 2.5 metres each separated by approximately 50 metres, which were part of the initial installation in 1971.[245] Event 31 was caused by a valve assembly that was installed in 2013 to replace and existing underground valve.[246]

108. As shown in the figures below, the MFL-C tool travelled above the typical optimal velocity range for a significant length after passing the two short heavy-wall pipe segments (in the case of Event 29) and the heavy-wall valve assembly (in the case of Event 31). In both cases, the tool traveled above the typical

243 As explained in the response to BCOAPO IR3 15.1 (Exhibit B-20), the cost of proactive replacement at Event 1 is within the lower range of estimated costs for both PLE options and the PLR alternative.

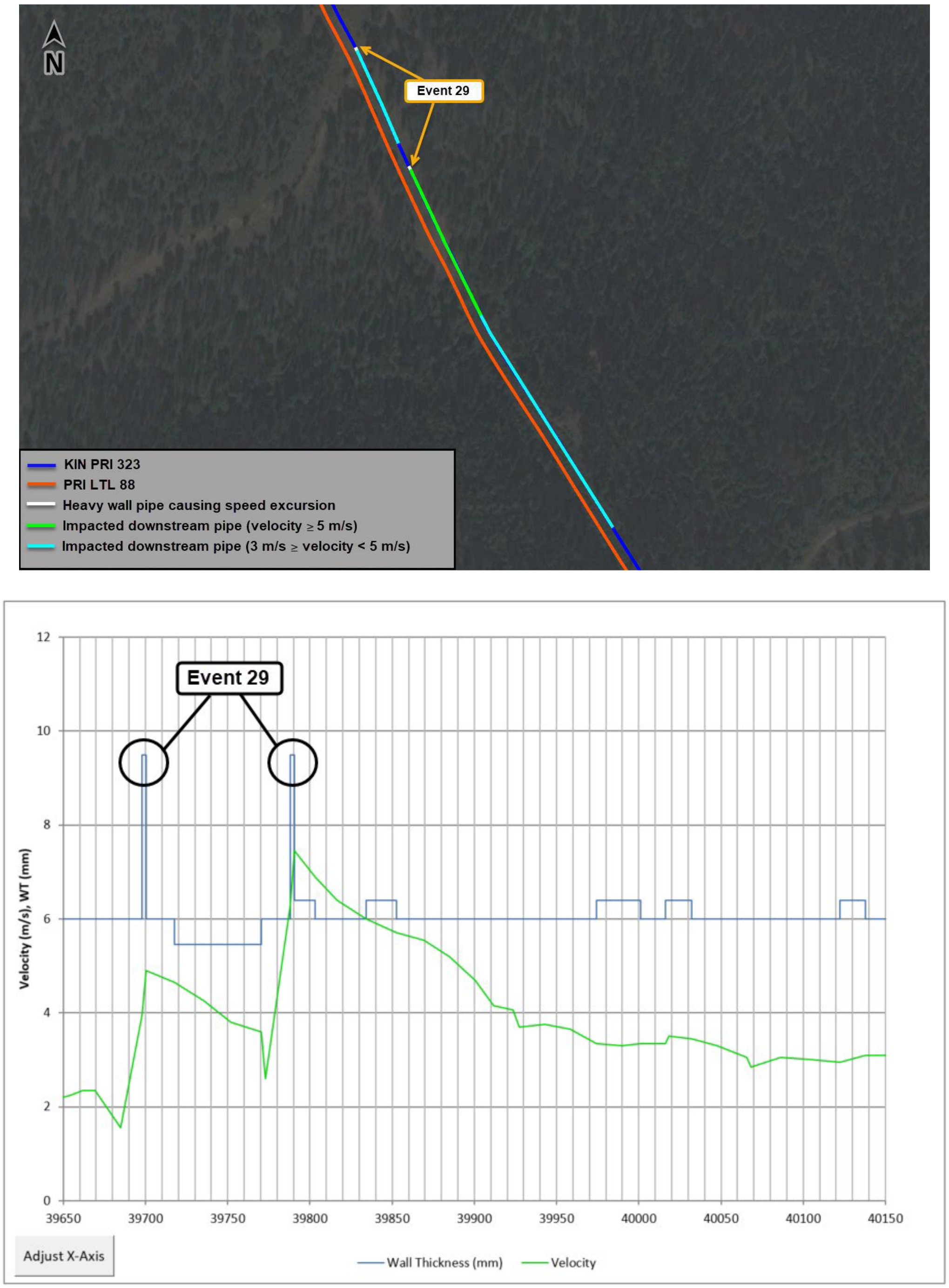
244 Exhibit B-20, BCOAPO IR3 15.1.

245 Exhibit B-1, Application, p. 91.

246 Exhibit B-1, Application, p. 92.

maximum velocity for MFL-C data collection and well in excess of the typical maximum velocity for EMAT data collection.[247]

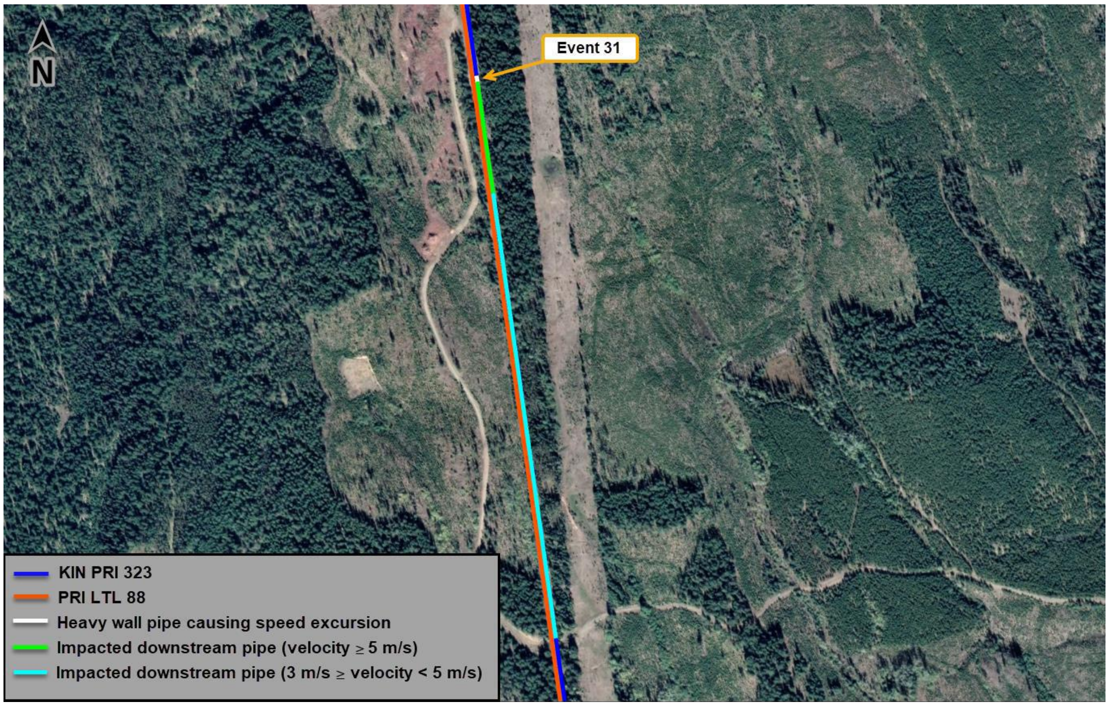
Figure 4: Event 29 Heavy Wall Pipe and Speed Excursion

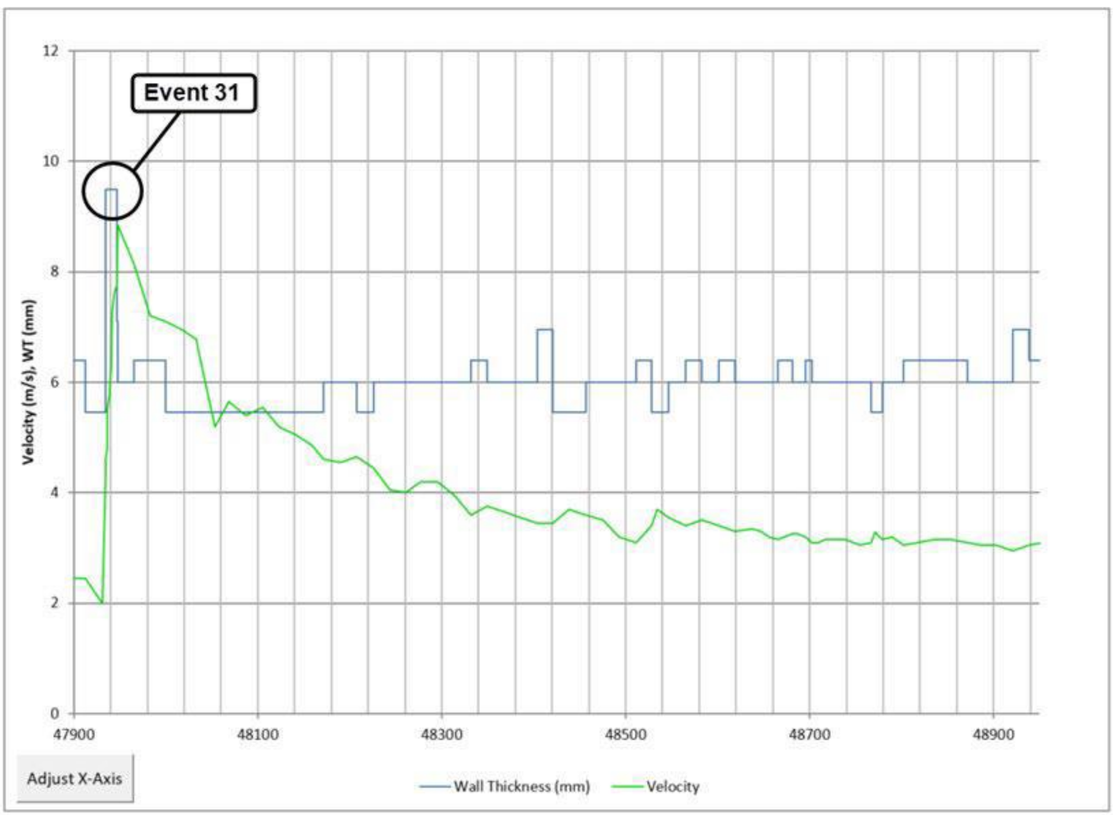


---

[247] Exhibit B-18-1, Rebuttal Evidence, A16.

Figure 5: Event 31 Heavy Wall Pipe and Speed Excursion





109. These speed excursion events affected approximately 112 metres of pipe.[248] The proactive replacement of these heavy-wall pipe segments is warranted for the reasons below:

- **Gas Supply to the CTS and Potential to Incur Higher Gas Costs:** FEI relies on the KIN PRI 323 and PRI OLI 323 pipelines to provide gas from TC Energy to the CTS. If these pipelines were operated at a reduced pressure for any reason, FEI would not be able to deliver up to a maximum of 105 MMSCFD of gas to the CTS, thus causing a capacity and corresponding gas supply impact.[249] For example, if FEI could not mitigate cracking on the downstream impacted pipe prior to winter and a pressure reduction were required to remain in place through the winter, FEI would not be able to deliver up to a maximum of 105 MMSCFD of gas to the CTS. FEI would then need to incur unplanned and much higher gas costs to secure the balance of supply for the CTS, which would be borne by customers. Based on current forward pricing for purchasing gas on the open market, incremental gas costs could be in the order of tens to hundreds of thousands of dollars per day, which would result in millions to tens of millions of dollars of incremental cost over a winter period.[250]

- **Alternative Mitigation Measures Would be More Impactful:** FEI expects that other options to mitigate cracking on the downstream impacted pipe, like PLE or PLR, will be more impactful (e.g., more severe environmental and archaeological impacts) and potentially more expensive due to the significant length of pipe requiring exposure and recoat or replacement.[251]

110. Ultimately, given the severity and length of the speed excursion observed at each of the three locations during previous MFL-C runs, the proactive replacement of these heavy-wall pipe segments is warranted.[252]

---

248 Exhibit B-8, RCIA IR1 11.5.

249 Exhibit B-18-1, Rebuttal Evidence, A16; Exhibit B-20, BCOAPO IR3 16.1.

250 Based on the price spread between the Sumas forward prices and the Station 2 full cost, which includes the Station 2 forward price, Westcoast 2022 tolls, and variable charges: Exhibit B-18-1, Rebuttal Evidence, A16 and Exhibit B-20, BCOAPO IR3 16.1.

251 Exhibit B-18-1, Rebuttal Evidence, A16.

252 Please refer to Table 2 of FEI's Rebuttal Evidence (Exhibit B-18-1) for a comparison of options for responding to blind spots.

(c) The Availability of Speed Control Capabilities Does Not Alter the Project Scope

111. Depending on the pipeline diameter, EMAT ILI tools can be equipped with a speed control valve. When determining the Project scope, FEI took into account the potential availability of speed control on EMAT ILI tools.[253] FEI is interested in running tools with speed control capabilities, thus potentially: (i) expanding the seasonal windows during which inspections can be scheduled; and (ii) improving the rate a tool returns to its optimal velocity and lowering its peak velocity following a speed excursion.[254] While this capability is not currently commercially available for any sizes of pipeline within the Project scope (i.e., NPS 10 and 12),[255] FEI expects EMAT tools for NPS 12 pipelines with speed control to be available by 2026, when the first ITS EMAT ILI runs are scheduled to begin.[256]

112. However, the availability of speed control does not change the scope of the Project for the following reasons:

- Only 5 of the 8 ITS pipelines within the Projects scope are NPS 12. No speed control capabilities will be available for the 3 remaining NPS 10 diameter pipelines.[257]

- Even for the NSP 12 pipelines, FEI cannot be certain that EMAT ILI tools with speed control will be available. There is only one vendor that is developing a speed control for this size of EMAT ILI tools. FEI's past practice has been to work with multiple vendors to undertake ILI runs and this approach is prudent and in the best interest of customers.[258] In particular, prioritizing a vendor solely based on the speed control capabilities of its EMAT ILI tools would limit FEI's ability to consider their other technical capabilities and would create sole-sourcing risks (e.g., increased run costs and scheduling limitations).[259]

- Running tools with speed control will not eliminate speed excursions that result in incomplete data collection and blind spots.[260] Further, the availability of speed control does not negate the need for flow control stations to assist in maintaining the EMAT ILI

---

253 Exhibit B-8, RCIA IR1 12.6, footnote 8.
254 Exhibit B-1, Application, Appendix D, p. 5.
255 Exhibit B-8, RCIA IR1 4.1.
256 Exhibit B-11, RCIA IR2 18.1.
257 Exhibit B-1, Application, Table 3-5 (p. 44).
258 Exhibit B-18-1, Rebuttal Evidence, A17.
259 Exhibit B-21, CEC IR3 5.2.
260 Exhibit B-18-1, Rebuttal Evidence, A18.

tool travel velocity within its optimal range, thus promoting conditions where quality data can be collected.[261]

B. The Project Cost Estimate is Robust and Meets the BCUC's CPCN Guidelines

113. Consistent with the BCUC's CPCN Guidelines, FEI and Tetra Tech[262] developed an AACE Class 3 estimate for the Project using AACE Recommended Practices Nos. 18R-97 and 97R-18 as guides.[263] The Class 3 Cost Estimate and Basis of Estimate are provided in Confidential Appendix G-3 to the Application.[264] As noted above, the total capital cost estimate for the ITS TIMC Project is $84.588 million, of which $71.894 million represents the capital cost with contingency (both in as-spent dollars).[265] FEI has also provided a detailed breakdown of the cost estimate for each of the 3 proposed pipeline alternations and 13 proposed facility alternations.[266] The cost estimate has been subject to quality assurance and validation through:[267]

- Internal reviews of Tetra Tech's assumptions, deliverables and document quality checks;
- Validation reviews involving both Tetra Tech and FEI team members throughout the estimate development process to confirm that the estimate assumptions were valid;
- Independent external reviews of the Class 3 cost estimate by Universal Pegasus International to verify[268] (from an engineering perspective) that the estimate criteria and requirements were met and a documented, reasonable estimate was developed; and
- An independent external estimate completed by Pipestone Projects to verify (from a construction perspective) that a suitable construction strategy, cost basis and estimating methodology were utilized.

---

261 Exhibit B-11, RCIA IR2 18.1.

262 Tetra Tech was selected as the preferred proponent for this work, among three pre-qualified pipeline engineering consultants with which FEI has long-term master services agreements: Exhibit B-7, CEC IR1 28.1.

263 Exhibit B-1, Application, p. 108. FEI also provided a P75 and P90 cost estimate in response to an intervener IR: Exhibit B-6, BCOAPO IR1 3.6.

264 Exhibit B-1-1, Confidential Application.

265 Exhibit B-1, Application, p. 1 and Table 5-5 (pp. 110-111); Exhibit B-7, CEC IR1 23.1.

266 Exhibit B-6, BCOAPO IR1 3.2.

267 Exhibit B-1, Application, pp. 111. Only the construction costs prepared for the modification to control and safety systems and the SN-4 PRS 6 (Appendix G-4 to the Application), as well as the owner's costs were not not subjected to an external, independent review: Exhibit B-7, CEC IR1 30.2 and Exhibit B-9, BCUC IR2 25.1.

268 See also Exhibit B-7, CEC IR1 30.1 which further describes the work undertaken by Universal Pegasus International.

As discussed further below, the Class 3 cost estimate for the Project includes a contingency estimate and a management reserve, and is informed by a risk analysis and probabilistic analysis of escalation.

114. First, FEI engaged Yohannes Project Consulting Inc. (YPCI), a company specializing in risk management, to conduct a qualitative risk analysis to identify all of the risks associated with the Project. YPCI conducted multiple workshops with impacted stakeholders to develop a risk register for the Project (Confidential Appendix H-2) to identify risks that could likely occur.[269] As the engineering advanced on the Project, the probability or the consequence of several risks which were initially identified were either mitigated entirely or reduced to a lesser extent. All of the remaining risks associated with the Project are contained within the Risk Report and included in Confidential Appendix E-1.[270]

115. Second, FEI used a contingency estimation and quantitative analysis prepared by Validation Estimating LLC, USA (Validation Estimating, John Hollmann) at a P50 confidence level to establish a project contingency percentage of 10.1 percent.[271] Validation Estimating's analysis is provided in Confidential Appendix E-3 to the Application.[272] The contingency amount reflects the current understanding of the Project's risk profile, discrete project risks and accounts for possible scope changes,[273] and was prepared using the same process used for determining the contingency requirements as that of the CTS TIMC Project.[274] In preparing the risk analysis, Validation Estimating facilitated a series of risk workshops to evaluate the systemic and project-specific risks with the extended project team, before qualifying the contingency to adequately address Project risks over a multi-year execution timeframe. The risk quantification process applied a hybrid approach:[275] (1) assessing the probability of occurrence; and (2) integrating anticipated cost and schedule impacts.[276] This hybrid approach accords with the AACE Recommended Practices.[277]

---

269 Exhibit B-1, Application, pp. 111-112 and Exhibit B-1-1.

270 Exhibit B-1, Application, pp. 111-112 and Exhibit B-1-1.

271 Exhibit B-1, Application, p. 112; Exhibit B-7, CEC IR1 31.1. The contingency amount is based on the ITS TIMC's base cost estimate of $58.364 million (in 2022 dollars).

272 Exhibit B-1-1, Confidential Application.

273 Exhibit B-1, Application, pp. 112-113.

274 Exhibit B-6, BCOAPO IR1 3.4.

275 This hybrid approach combined a parametric model analysis for systemic risks based on empirical knowledge, and an expected value analysis for project specific risks: Exhibit B-1, Application, p. 113.

276 Exhibit B-1, Application, p. 113.

277 These AACE Recommended Practices include: (1) 40R-08 Contingency Estimating – General Principles; (2) 42R-08 Risk Analysis and Contingency Determination Using Parametric Estimating; and (3) 65R-11 Integrated Cost and Schedule Risk Analysis and Contingency Determination Using Expected Value: Exhibit B-1, Application, p. 113.

116. Third, Validation Estimating completed a probabilistic assessment of escalation, provided in Confidential Appendix H-4 to the Application, which establishes the escalation at $7.630 million (11.9 percent of the total base cost plus contingency) that aligns with the P50 confidence level.[278] This approach is consistent with AACE Recommended Practice 68R-11.

117. Finally, FEI has also included a management reserve of $5.0 million (8.6 percent of the base cost estimate) based on the contingency analysis and recommendation from Validation Estimating, as set out in Confidential Appendix H-3.[279] A management reserve is intended to cover project-specific risks with a low probability but high impact which, in the case of the ITS TIMC Project, addresses three risks identified by Validation Estimating.[280] FEI can only use the management reserve if any of these project-specific risks materialize.[281]

118. In the BCUC's decision in the CTS TIMC CPCN proceeding, the Panel accepted FEI's approach to cost estimating, including the contingency and escalation estimate prepared by Validation Estimating, which the BCUC noted is an "independent external party".[282] FEI has employed the same approach to cost estimating for the ITS TIMC Project.

119. FEI submits that its cost estimate for the Project meets the BCUC CPCN Guidelines and is both reasonable and robust.

C. The Timeline for the ITS TIMC Project Is Reasonable and Reflects the Potentially Significant Consequences of Delay

120. The ITS TIMC Project should proceed based on the planned Project schedule in order to conduct baseline EMAT ILI runs from 2026 to 2032. While FEI is satisfied that this is a reasonable timeline on which to implement EMAT ILI, cracking is a threat that increases over time. Therefore, a delay to the implementation of the Project would prevent FEI from identifying cracking on its ITS pipelines, which could have significant consequences.

---

278 All cost estimates, including material supply and construction contracts, were developed based on 2022 market prices: Exhibit B-1, Application, p. 113 and Exhibit B-1-1.

279 Exhibit B-1, Application, p. 113.

280 The risks identified by Validation Estimating are: (1) construction market risk; (2) low probability/high impact archaeological risk; and (2) wildfire risks: Exhibit B-1-1, Confidential Appendix H-3, p. 13.

281 Exhibit B-6, BCOAPO IR1 3.5.

282 BCUC Decision and Order C-3-22, p. 38.

121. FEI first identified the need for the Project in 2018 and has pursued the Project on a reasonable and measured timeline. While FEI prioritized its CTS TIMC Project due to the higher safety risk of the CTS pipelines (as compared to the ITS pipelines), and in contemplation of the originally planned in-service date of the OCU Project (Q3 2023), FEI must proceed with the ITS TIMC Project on the proposed timeline for the following reasons:[283]

- 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. In particular, although the extent of any actual cracking cannot be known until EMAT ILI is implemented, there has been ample time for cracks to develop and grow in the 8 ITS pipelines, as many of these pipelines were installed in 1957.
- EMAT ILI is a proven and commercialized technology that is now available to proactively monitor cracking threats. 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.
- FEI has regulatory obligations to mitigate cracking threats to its transmission pipelines. FEI describes these obligations in Section 3.5.2 of the Application and discusses the regulation and regulation-driven (e.g., CSA Z662) requirements in the response to BCUC IR1 7.1.

122. The need for the ITS TIMC Project, and the Project schedule proposed in the Application, is also appropriate given that the potential reliability and safety consequences associated with a failure are significant. In particular, 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.[284] As described in Section 3.5.3.3 of the Application, during high demand conditions, the ITS pipelines are effectively uni-directional (i.e., reliant

[283] Exhibit B-4, BCUC IR1 1.2; Exhibit B-15, BCUC Panel IR1 1.3.
[284] Exhibit B-4, BCUC IR1 5.3.

on the dominant supply coming from one direction) and generally not looped. Therefore, if a pipeline failure occurs, especially during cold winter conditions, gas supply to communities fed by the various gate stations and laterals could be lost – potentially resulting in safety consequences.[285] Indeed, depending on the time of year and the location of a rupture along the SAV VER 323 and the connected VER PEN 323 pipeline (which make up the Savona to Penticton 323 mainline), between approximately 5,000 and 105,000 customers could lose service in communities between Savona and Penticton if a rupture were to occur.[286]

123. FEI has accounted for both the safety and customer supply interruption risk in the proposed timing for executing the ITS TIMC Project events and post-Project EMAT tool runs. Alterations required to support EMAT ILI on the Savona to Penticton 323 mainline are scheduled to be completed first, followed by alterations to the remainder of the pipelines.[287] Baseline runs have been projected two years apart at the current stage of project planning to avoid multiple concurrent pressure reductions on ITS mainlines, and associated customer supply interruption. If a pressure reduction is not required after a baseline run, the next baseline runs could be undertaken sooner.[288] Of the 8 ITS pipelines, the SAV VER 323 and VER PEN 323 pipelines have the highest estimated safety risk and the earliest occurring capacity limitations, which dictated the scheduled baseline EMAT ILI run in 2026.[289]

124. The availability of proven and commercialized EMAT ILI technology, identification of emerging changes in industry practice to adopt EMAT ILI, completion of the baseline system-level QRA and lack of clear benefits to be achieved from delaying the ITS TIMC Project support the priority and urgency FEI has assigned to it.[290] FEI submits that the evidence overwhelmingly supports FEI proceeding with the Project as planned.

[285] Exhibit B-1, Application, p. 54.
[286] Exhibit B-1, Application, p. 55. See Exhibit B-7, CEC IR1 in which FEI provides the potential customer impact of different pipeline groupings.
[287] Exhibit B-4, BCUC IR1 4.2.
[288] Exhibit B-4, BCUC IR1 4.2.2.
[289] Exhibit B-4, BCUC IR1 4.2; Exhibit B-8, RCIA IR1 15.3.
[290] Exhibit B-4, BCUC IR1 5.3 and Exhibit B-7, CEC IR1 26.1. The timeline for implementing the ITS TIMC Project is not constrained by the availability of suitable EMAT tools, but did inform FEI's decision-making process when determining a timeline for initiating the TIMC projects generally: Exhibit B-4, BCUC IR1 4.1.

D. Proposed Treatment of TIMC Development Cost Deferral Account Balance is Just and Reasonable

125. In Order G-237-18, the BCUC approved the creation of the non-rate base TIMC Development Cost deferral account, attracting a weighted average cost of capital (WACC) return, which FEI has used to capture: (1) CPCN application costs, including those associated with this Application; (2) preliminary stage development costs; and (3) pre-construction development costs related to the TIMC projects, including the EMAT ILI pilot projects and the CTS and ITS TIMC projects. FEI has tracked and recorded the costs associated with the ITS TIMC Project separately, and is now seeking approval to begin amortization of these costs.

126. Consistent with the approved treatment of similar costs through BCUC Order C-3-22, FEI is seeking approval, pursuant to sections 59 to 61 of the UCA, to:[291]

- Capitalize pre-construction development costs associated with the ITS TIMC Project by transferring them to construction work-in-progress (CWIP); and

- Transfer the remaining costs in the existing non-rate base TIMC Development Cost deferral account to the existing rate base TIMC Development Cost deferral account, which has an approved[292] amortization period of 5 years.

127. FEI has provided a continuity of the Application costs and pre-construction development costs, including the calculation of the income tax recovery and the costs capitalized to CWIP. FEI estimates that the total pre-construction costs capitalized at the end of 2023 will be $4.108 million. FEI also estimates that the closing balance in the deferral account in 2023 will be $0.574 million. Thus, the total net costs captured by the deferral account is $3.535 million.[293]

---

291 Exhibit B-1, Application, p. 120. Please note that 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. In particular, 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: Exhibit B-4, BCUC IR1 11.1.

292 As approved by BCUC Decision and Order C-3-22.

293 Exhibit B-4, BCUC IR1 11.2.

PART FIVE: FEI WILL MITIGATE ENVIRONMENTAL AND ARCHAEOLOGICAL IMPACTS

128. FEI will employ best management practices and mitigation measures to minimize and avoid the potential archaeological and environmental impacts caused by the Project. Based on the environmental and archaeological assessments undertaken to date, the ITS TIMC Project is expected to have low to moderate environmental impacts, while the areas in which the 3 pipeline modifications and 13 facilities alterations are located may have moderate to high archaeological potential. In both cases, any potential impacts can be appropriately mitigated and FEI will include all environmental and archaeological impacts that are assessed as moderate to high in the project risks section of the progress reports to the BCUC.[294]

129. The Environmental Overview Assessment (EOA) of the Project, which is included as Appendix K to the Application, was completed by Wood Environment and Infrastructure Solutions (now WSP)[295] and concludes that the overall environmental risk of the Project is low to moderate, reflecting varied impacts between locations.[296] The assessment also concludes that potential impacts can be mitigated through the implementation of standard best management practices, which FEI will follow during construction.[297] As described in Section 10 of the EOA, FEI will also develop site specific mitigation strategies to offset any potential impacts associated with the Project and potential impacts caused by the environment.[298]

130. FEI will undertake further environmental assessments to confirm environmental permitting requirements during the detailed engineering phase of the Project and will then apply for permits as required. At this stage of Project development, FEI has identified certain permits (e.g., Notification for Changes in and about a Stream) that will be required and others that may be required (e.g., Notice of Intent for soil deposition or removal for soils in the Agricultural Land Reserve).[299] Once construction begins, FEI will undertake environmental monitoring to oversee construction activities, identify any adverse effects and, ultimately, to verify that the construction site is returned to pre-construction conditions as soon as possible.[300] Further, a qualified environmental professional ensure compliance with requirements of the Environmental Management Plan (EMP), Environmental Protection Plans (EPP), and

---

294 Exhibit B-1, Application, Section 7; Exhibit B-12, BCOAPO IR2 11.1.

295 As an existing FEI contractor and provider of technical services, FEI selected WSP due to their ability to meet project timelines: Exhibit B-7, CEC IR1 35.2.

296 Exhibit B-1, Application, Appendix K, Table 18.

297 Exhibit B-1, Application, p. 131.

298 Exhibit B-1, Application, p. 131.

299 Exhibit B-4, BCUC IR1 14.1 and 14.2.

300 Exhibit B-1, Application, p. 132.

applicable permits.[301] FEI will also be conducting post-construction inspections to determine the success of restoration efforts and mitigation measures.[302]

131. FEI also retained Wood Environmental and Infrastructure Solutions to complete an Archaeological Overview Assessment (AOA), included as Appendix L to the Application.[303] The AOA identifies the archaeological and historical heritage resources overlapping with the Project's 3 proposed pipeline modifications and 13 alterations to facilities.[304] The AOA did not identify any registered archaeological sites or registered historic heritage sites overlapping the areas within the Project scope.[305] FEI obtained all required Indigenous cultural permits prior to commencing the AOA[306] and, as summarized in Table 7-7 of the Application, potential impacts to archaeological and historic heritage sites will be further assessed as part of: (1) an Archaeological Impact Assessment (AIA) for those pipelines and facilities with moderate to high archaeological potential; (2) additional Preliminary Field Reconnaissance (PFR); and (3) archaeological monitoring prior to, or concurrent with, construction.[307] In particular, the AIA will provide a detailed assessment to develop site specific mitigation strategies to offset any potential impacts associated with the Project.[308] Any potential archaeological impacts of the Project can be mitigated through the implementation of permit conditions and standard best management practices.[309]

132. Finally, FEI requires a permit under Section 12.2 of the *Heritage Conservation Act* to undertake detailed AIA activities, which FEI will obtain during the detailed engineering phase of the Project. FEI's archaeological consultant will obtain any Indigenous cultural heritage permits at the time of the AIA.[310] All potentially impacted Indigenous groups will also be invited to participate in AIA and PFR work and will have the opportunity to provide additional information and make comments on the draft report.[311]

301 Exhibit B-1, Application, p. 132.
302 Exhibit B-1, Application, p. 132.
303 Exhibit B-1. FEI achieved cost savings of approximately $5 thousand in project management fees by using a single company for the EOA and AOA: Exhibit B-7, CEC IR1 35.3.
304 Exhibit B-1, Application.
305 Exhibit B-1, Application, p. 133.
306 Exhibit B-1, Application, p. 133.
307 Exhibit B-1, Application, pp; 123, 133-134.
308 Exhibit B-1, Application, p. 134.
309 Exhibit B-1, Application, p. 135.
310 Exhibit B-1, Application, p. 134.
311 Exhibit B-1, Application, p. 134.

PART SIX: FEI'S ENGAGEMENT ACTIVITIES WILL CONTINUE TO BE SUFFICIENT

133. This Part of this Final Submission discusses how FEI's consultation and engagement with the public and Indigenous groups has been sufficient, and that there have not been any significant issues or concerns raised with respect to the Project. FEI's approach to consultation and engagement is guided by a Consultation and Engagement Plan (Appendix M-1 to the Application) which ensures the public and Indigenous groups have a meaningful opportunity to learn about and provide input into the Project. FEI initiated consultation and engagement for the Project in May 2021 and will be continuing to consult with the public and engage with Indigenous groups throughout the life of the Project.[312]

A. <u>Public Consultation Has Been Sufficient and Does Not Indicate Significant Concerns</u>

134. As set out in the Application, FEI identified and adopted a number of objectives to guide public consultation which are consistent with industry best practices:[313]

- Ensure balanced and objective information is provided to all affected and interested stakeholders;
- Communicate the benefits of the Project (e.g., reliability and integrity of FEI's system), and potential positive socio-economic impacts to communities during construction;
- Provide opportunities for stakeholders to give feedback and to understand their concerns through an ongoing dialogue; and
- Consider and, where possible, incorporate stakeholder feedback.

135. These objectives allow FEI to solicit community feedback throughout the Project. As part of its Consultation and Engagement Plan, FEI identified a number of stakeholders, including: 12 municipalities and regional governments, FEI customers, permitting authorities, and residents and businesses along and nearby the Project rights of ways and worksites.[314] Community, social and environmental considerations

---

312 Exhibit B-1, Application, Section 8.

313 Exhibit B-1, Application, pp. 137-138. FEI also considers the International Association of Public Participation (IAP2) spectrum of public participation, and its own experience on other major projects to inform its engagement and consultation planning: Exhibit B-6, BCOAPO IR1 4.1 and 4.2.

314 Exhibit B-1, Application, p. 138.

informed this plan, and as set out in Table 8-1 of the Application, enabled FEI to identify potential impacts to the public and an associated approach to consultation and mitigation.[315]

136. In order to support its consultation activities, FEI developed a number of communication materials, including: (i) project information letters; (ii) a project webpage, email address and phone line; and (iii) information sharing through its Talking Energy newsletter, its various social media channels and to all gas customers through a bill insert.[316] To date, there are no outstanding concerns or further issues raised by stakeholders.

137. As described in detail in Section 8.2.4 of the Application, FEI's consultation methods are tailored to each group, including potentially impacted residents, businesses, and municipalities, through a variety of methods. For example, FEI mailed project-related letters to 14 directly affected landowners along the rights of way, and in direct proximity to worksites, and follow-up with phone calls confirming they received the letter, gathering feedback and addressing any outstanding concerns.[317]

138. FEI submits that its Consultation and Engagement Plan and associated public consultation activities have been sufficient, appropriate, and reasonable to meet the requirements of the CPCN Guidelines. Throughout the consultation process to date, FEI has addressed questions and issues, and is not aware of any outstanding concerns.[318] FEI will continue to consult with stakeholders regarding construction timelines, scope of work, safety, and mitigation plans.[319]

139. Ultimately, FEI is dedicated to maintaining open dialogue and good relationships with its customers, residents and businesses, municipalities and permitting agencies throughout the various stages of construction and will work with them to minimize the impacts of the Project.[320] FEI is not aware of any outstanding concerns and is committed to responding to the feedback received from stakeholders as the Project continues to develop.

---

315 Exhibit B-1, Application, p. 142.
316 Exhibit B-1, Application, pp. 138-140 and 143, Appendices M-3 to M-6.
317 Exhibit B-1, Application, p. 140.
318 Exhibit B-9, BCUC IR2 27.1.
319 Exhibit B-1, Application, p. 143.
320 Exhibit B-1, Application, p. 143.

B. Engagement with Indigenous Groups Has Been Reasonable, Adequate and Meaningful

140. To date, FEI has been able to address all questions and concerns raised by Indigenous groups and considers that its early engagement activities have been successful in understanding the level of interest and the nature of interests of Indigenous groups for the Project, reflecting this stage in the Project lifecycle.[321] Given the stage of the Project, FEI submits that its engagement activities with Indigenous groups to date have been reasonable and adequate, as well as being consistent with the BCUC's CPCN Guidelines.

141. As outlined in Section 8.3 of the Application, FEI began engaging with all Indigenous groups with asserted interests in the Project in May 2021.[322] FEI initiated early engagement activities with 35 Indigenous groups that may potentially be affected by the Project, as well as their representative organizations (as applicable), to: (1) provide information about the Project; (2) describe any potential impacts; (3) understand the interests in the area; and (4) provide an opportunity for these groups to identify additional impacts and to give input on the Project. Through this early engagement process, FEI has established key points of contact with Indigenous groups potentially affected by the Project and their preferred methods of communication, as well as sharing information about the Project and potential opportunities for Indigenous involvement.[323]

142. Engagement was initiated with these groups through a Project information letter, preliminary maps and reports, and has progressed through follow-up calls and meetings when requested by Indigenous groups, including meetings with the Skeetchestn Indian Band and Tk'emlups te Secwepemc.[324] Both the Penticton Indian Band and Westbank First Nation have offered conditional approval for the Project within their respective territories / areas of responsibility. A number of Indigenous groups have also indicated an interest in engaging on future archaeological and environmental reports and plans as they become available and through the BCER permitting process, closer to Project construction.[325] FEI has also provided any requested information to groups as available.[326]

---

321 Exhibit B-1, Application, Table 8-3 (pp. 146-148); Exhibit B-9, BCUC IR2 27.2; Exhibit B-7, CEC IR2 40.1.

322 FEI provides a list of Indigenous groups with asserted identified interests in Table 8-3 of the Application (Exhibit B-1).

323 Exhibit B-1, Application, pp. 146 and 148.

324 Exhibit B-1, Application, p. 145 and Table 8-3 (pp. 146-148); Exhibit B-6, BCOAPO IR1 4.3.

325 Exhibit B-1, Application, Table 8-3 (pp. 146-148); Exhibit B-9, BCUC IR2 27.2.

326 Exhibit B-1, Application, Table 8-3 (pp. 146-148); Exhibit B-9, BCUC IR2 27.2.

143. As the Project progresses into later stages, FEI will continue to work with Indigenous groups to keep them apprised of new developments, including addressing any follow-up commitments. In particular, FEI will engage Indigenous groups during the permitting process and will communicate and solicit feedback regarding construction timelines, scope of work, and safety and mitigation plans.[327] This includes engagement regarding site-specific impacts through the BCER permitting process, which includes sharing the results of environmental and archaeological reports and engagement on site-specific impacts through the BCOGC permitting process.[328]

144. FEI's approach ensures that Indigenous groups can obtain relevant information regarding the Project and its potential impact to their interests (e.g., the above-noted results of environmental and archaeological reports) as it becomes available. FEI also intends to consider, and where appropriate, incorporate feedback from Indigenous groups throughout the Project lifecycle, including Project planning, construction and restoration.[329] This approach is consistent with its Statement of Indigenous Principles,[330] and FEI will continue to include all groups that are potentially affected by the Project.[331] FEI has taken the same approach in relation to previous projects, including the CTS TIMC Project, thus ensuring an open dialogue and long-term relationships with Indigenous groups.

145. FEI is also supporting Indigenous engagement activities by offering capacity funding throughout the project lifecycle, thus facilitating Indigenous engagement regarding the Project's potential impacts on their rights and interests.[332] This funding is typically used for member meetings with FEI staff, public community meetings, and reviewing and providing feedback on the Project – including through participation in environmental and archaeological assessments and subsequent monitoring work.[333] 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.[334] FEI has not received any formal requests to support engagement capacity from Indigenous groups, or any indication that such requests

327 Exhibit B-1, Application, pp. 148-149; Exhibit B-4, BCUC IR1 15.1.
328 Exhibit B-4, BCUC IR1 15.1.
329 Exhibit B-12, BCOAPO IR2 10.2.
330 Exhibit B-1, Application, Appendix N.
331 Exhibit B-9, BCUC IR2 27.2.
332 Exhibit B-4, BCUC IR1 15.2.
333 Exhibit B-9, BCUC IR2 26.1.
334 Exhibit B-4, BCUC IR1 15.2.

will be forthcoming. Due to the locations, nature, scale and scope of the work, FEI anticipates minimal Project interest, and as a result, minimal requests for capacity funding.[335]

146. As outlined above, FEI's engagement activities with Indigenous groups to date have been reasonable and adequate, and are consistent with the BCUC's CPCN Guidelines. FEI has notified each identified Indigenous community about the Project, and where requests were made for more detail than is currently available, FEI has committed to ongoing engagement through follow-up meetings to share information as it becomes available. During the BCER permitting and consultation process, more detailed Project information will be provided to the Indigenous communities for review and comment.

---

[335] Exhibit B-9, BCUC IR2 26.2.

PART SEVEN: THE PROJECT IS CONSISTENT WITH PROVINCIAL ENERGY OBJECTIVES AND LONG TERM RESOURCE PLAN

147. As outlined in Section 9 of the Application, the ITS TIMC Project is consistent with British Columbia's energy objectives and long term gas resource plans, as well as aligning with FEI's decarbonization goals.[336]

A. <u>The Project Will Encourage Economic Development and the Creation and Retention of Jobs</u>

148. The Project will support the British Columbia energy objective in section 2(k) of the *Clean Energy Act* (CEA), "to encourage economic development and the creation and retention of jobs", by creating jobs in BC through FEI's contractors and contributing to the local economy through increased use of local services and the procurement of goods and services from businesses located in, or close to, the municipality and/or the regional district in which the Project is to be located and undertaken.[337]

149. Given the significant economic opportunity the Project would provide for the region, reflecting its construction cost estimate of $50.2 million, 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. While it remains premature for FEI to quantify the Project's potential economic impact, for comparison, approximately 64 percent of the $128 million spent on the IGU Project was sourced to BC based businesses, with a further 22 percent sourced to Indigenous-owned and affiliated vendors.[338] 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, and is developing a metric to track and monitor FEI's engagement with key communities on an annual basis.[339] To date, local and Indigenous vendors have expressed their interest in participating in procurement opportunities related to the Project.[340]

B. <u>The Project Will Support FEI's Decarbonization Goals</u>

150. As explained in Part Two, Section A(c) of this Final Submission, the ITS TIMC Project is driven by risks posed by credible cracking threats on ITS pipelines; however, it will also support and indirectly help

---

336 Exhibit B-1, Application, pp. 150-151.
337 Exhibit B-1, Application, p. 150; Exhibit B-4, BCUC IR1 16.1.
338 Exhibit B-4, BCUC IR1 16.2.
339 Exhibit B-4, BCUC IR1 16.2 and 16.3.1.
340 Exhibit B-4, BCUC IR1 16.3.

to meet FEI's decarbonization goals and to decarbonize BC's industrial sector to meet BC's climate targets, including the measures in the CleanBC Roadmap. This purpose is consistent with FEI's accepted 2017 Long Term Gas Resource Plan (LTGRP) and the utility's most recently filed 2022 LTGRP – both of which contemplate the deployment of EMAT ILI on FEI's system.[341]

151. FEI's existing pipeline infrastructure will play an important role in reducing greenhouse gases by transitioning to delivering an increasing share of renewable and low-carbon energy over time.[342] In particular, as the ITS pipelines are capable of safely transporting a blend of hydrogen, and will continue to be used and useful,[343] FEI is developing a safe and cost-effective plan for transitioning to increased hydrogen distribution with goals over the near, medium and long term in order to meet the provincial energy objectives outlined in the CleanBC Roadmap. For example:[344]

- **Over the next five years**, FEI will be considering a number of approaches to locally displace conventional natural gas in the gas system by incorporating the use of renewable and low carbon gases such as renewable natural gas (RNG), as well as opportunities to distribute hydrogen directly to gas customers through dedicated infrastructure.

- **In the medium term (projected to be by 2030)**, FEI expects to expand blends of hydrogen 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.

152. As material compatibility and pipeline integrity are dominant considerations in assessing the concentration of hydrogen that could be blended into the system,[345] information gathered as part of engineering assessments, including through in-line inspection tools (MFL, C-MFL and EMAT), will factor

---

[341] Exhibit B-1, Application, p. 150.
[342] Exhibit B-4, BCUC IR1 17.3.
[343] Please refer to Exhibit B-7, CEC IR1 33.1 where FEI explains why a 65 years average service life is appropriate.
[344] Exhibit B-4, BCUC IR1 17.2.
[345] Exhibit B-8, RCIA IR1 17.1.

into FEI's analysis regarding the concentration of hydrogen each pipeline can safely accommodate in the future.[346] In particular, where data about a pipeline is unknown, EMAT ILI data will improve FEI's ability to characterize pipe segments (in addition to material testing and review of pipeline records) in order to examine the compatibility of a given steel with hydrogen and the associated risk of hydrogen degradation.[347] Further, once hydrogen is introduced onto the ITS, EMAT ILI tools will assist in managing the integrity of its system.[348]

153. Ultimately, the ITS will support the utility meeting its decarbonization goals and BC's climate targets.

---

346 Exhibit B-1, Application, p. 151; Exhibit B-4, BCUC IR1 17.1 and 17.2.2.
347 Exhibit B-8, RCIA IR1 17.1; Exhibit B-4, BCUC IR1 17.2.2.
348 Exhibit B-10, CEC IR2 50.1.

PART EIGHT: CONCLUSION

154. FEI submits that the BCUC should grant a CPCN for the Project and approve the transfer of the balance of the TIMC Development Cost deferral account related to the ITS TIMC Application from the existing non-rate base deferral account to the existing rate base TIMC Development Cost deferral account.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Dated:	September 19, 2023	***[original signed by Chris Bystrom]***
		Chris Bystrom
		Counsel for FortisBC Energy Inc.
Dated:	September 19, 2023	***[original signed by Niall Rand]***
		Niall Rand
		Counsel for FortisBC Energy Inc.