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 +1 604 631 4715
Facsimile +1 604 632 4715
cbystrom@fasken.com

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

Attention: Mr. Patrick Wruck,
Commission Secretary and Manager, Regulatory Support

Dear Sirs/ Mesdames:

Re: FortisBC Energy Inc. ("FEI")
Certificate of Public Convenience and Necessity Application for the Inland Gas Upgrade Project
Project No. 1598988 - Final Submission

In accordance with the Regulatory Timetable set out for this proceeding by Order G-219-19, we enclose for filing FEI's Final Submission.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Christopher Bystrom]

Christopher R. Bystrom

CRB/jr
Encl.

British Columbia Utilities Commission

FortisBC Energy Inc.

Certificate of Public Convenience and Necessity Application for the Inland Upgrades Project

BCUC Project No. 1598988

Final Argument

of

FortisBC Energy Inc.

September 27, 2019

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PART ONE: INTRODUCTION

A. Overview of Application and Proceeding

1. FEI filed its Application to the British Columbia Utilities Commission ("BCUC") for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrades Project (the "Application") on December 17, 2018.[1] FEI is seeking a Certificate of Public Convenience and Necessity ("CPCN") for the Inland Gas Upgrades Project (the "Project") pursuant to sections 45 and 46 of the *Utilities Commission Act* (the "UCA"), and a deferral account pursuant to sections 59 and 61 of the UCA to capture the costs of preparing the Application and evaluating the feasibility of and preliminary stage development of the Project.

2. As described in the Application,[2] the Project is a pipeline-integrity project and is concerned in particular with improving how FEI manages external corrosion, which is the leading cause of pipeline failures. The 29 transmission laterals within the scope of the Project (the "29 Transmission Laterals") are the only remaining pipelines on FEI's system[3] that:

(a) are currently not able to be in-line inspected;

(b) operate at a stress level that makes them susceptible to failure by rupture due to corrosion; and

(c) are 6 inches in diameter or greater, which is large enough for in-line inspection tools to run through.[4]

3. The significance of the above is as follows. First, as these pipelines were not constructed to enable in-line inspection, FEI relies on proactive measures (coatings and cathodic protection) and above-ground detection methods, which cannot prevent and detect all occurrences of corrosion.[5] Second, due to the stress levels under which these pipelines

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1 Exhibit B-1 and Confidential Exhibit B-1-1. FEI filed an Evidentiary Update and Errata to the Application on April 5, 2019 (Exhibit B-1-2 and Confidential Exhibit B-1-2-1).

2 Exhibit B-1, Section 3.

3 The single remaining transmission pipeline is the Tilbury LNG Plant 168 mm lateral. Please refer to Exhibit B-2 the response to BCUC IR 1.5.1 for a discussion of why this lateral was excluded from the Project scope.

4 Exhibit B-5, CEC IR 1.1.1.

5 Exhibit B-1, p. 21.

operate, corrosion could cause these pipelines to fail by rupture (as opposed to leak), which can have significant consequences.[6] FEI is required by Canadian Standards Association Oil & Gas Pipeline Systems standard, CSA Z662, which is prescribed by the *Pipeline Regulation* under the *Oil and Gas Activities Act* ("OGAA"), to take measures to monitor, and mitigate or eliminate, hazards that can led to failure of pipelines operating under this stress level.[7] Third, these pipelines are large enough to be in-line inspected using in-line inspection technology. Moreover, industry standard practice has evolved with the development of in-line inspection technology such that pipelines of this size should now be in-line inspected to prevent failure by rupture.[8] Consistent with industry practice, all of FEI's other pipelines of this size or greater that operate at this stress level are already subject to in-line inspection to prevent failure.[9]

4. Therefore, as a prudent operator, FEI must carry out the Project to meet its regulatory requirements under CSA Z662 and bring its integrity management of the 29 Transmission Laterals in line with industry practice, similar to how FEI manages all of its other pipelines of similar size or larger that operate at these stress levels.

5. FEI considered all reasonable alternatives and, using a comprehensive decision matrix, selected the most cost-effective alternative for each of the laterals that will mitigate the potential for failure by rupture due to external corrosion. Specifically, for each lateral, FEI will either: retrofit the lateral to provide in-line inspection capability (the "ILI" alternative"); construct a pressure regulating station to reduce the operating pressure (the "PRS" alternative); or replace the lateral with new pipe designed to operate at lower operating pressure and be capable of ILI in the future if needed (the "PLR" alternative).

6. The public process to review the Application has included three rounds of information requests and an oral presentation and question period ("workshop") as part of the procedural conference held on July 10, 2019. FEI's responses to information requests have been complete and thorough, responding to all issues raised and substantiating FEI's evidence as filed in the

6 Exhibit B-1, p. 19.

7 Exhibit B-2, BCUC IR 1.9.1.

8 Exhibit B-1, pp. 22-25.

9 Transcript, pp. 16-17

Application. To ensure that FEI could provide full and complete responses to the questions asked, FEI retained the services of JANA Corporation (JANA) to provide independent expert opinions on particular engineering matters, particularly as they relate to quantitative risk assessments. Dr. Ken Oliphant and Mr. Wayne Bryce, principals of JANA, are recognized pipeline industry experts, as demonstrated by their curriculum vitae filed as Attachment 62.1A to Exhibit B-10. Dr. Ken Oliphant and Mr. Wayne Bryce are, in particular, experts in quantitative risk assessments, and currently advising FEI on preparing such an assessment.[10]

7. FEI's engineering team and third party experts from JANA appeared at the workshop. FEI's presentation at the workshop addressed the key issues raised in the first two rounds of information requests. FEI's internal experts and those from JANA responded to numerous questions from the BCUC Panel, Staff and interveners on the evidence filed. The answers of FEI and JANA were detailed and complete, demonstrating their expertise in the subject matter, and addressing all issues raised.[11] No evidence has been filed by any party in this proceeding questioning the engineering judgment or expertise of either FEI or JANA.

8. FEI submits that the evidence in this proceeding is compelling and demonstrates that the Project is in the public interest. FEI must carry out the Project to mitigate the potential for the 29 Transmission Laterals to fail by rupture due to external corrosion, consistent with its regulatory obligations set out in CSA Z662 and industry standard practice. FEI has consulted with the British Columbia Oil and Gas Commission ("BC OGC") regarding the Project, and the BC OGC has stated that it "is supportive of FEI taking action to address its known integrity concerns and to ensure that it meets its requirements as a permit holder under the Oil and Gas Activities Act."[12]

9. Therefore, FEI submits that the BCUC should issue the order sought in the Application:

- granting a CPCN for the Project pursuant to sections 45 and 46 of the UCA; and

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10 Exhibit B-10, BCUC IR 2.36.1; Exhibit B-10, Attachment 36.1

11 Workshop Transcript.

12 Exhibit B-18, Attachment 67.1.

- approving a deferral account pursuant to sections 59 and 61 of the UCA to capture the costs of preparing the Application and evaluating the feasibility of and preliminary stage development of the Project.

10. A draft order is included as Appendix T-1 of the Application.

B. Organization of this Submission

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

- Part Two will discuss how the Project is necessary and justified as it is required to the 29 Transmission Laterals failing by rupture due to corrosion, consistent with FEI's regulatory obligations under CSA Z662 and industry standard practice.

- Part Three will describe FEI's careful analysis of the alternatives for the Project, and how FEI's preferred alternative for each of the 29 Transmission Laterals is the most cost-effective feasible alternative.

- Part Four will describe the extensive evidence filed on the scope and cost estimate for the Project, including how FEI's cost estimate is a Class 3 AACE estimate and has appropriately included cost contingency and reserve.

- Part Five will describe how the environmental overview assessment and archaeological overview assessment shows that the IGU Project will have minimal environmental impact and that the majority of the expected Project footprint is considered to have low archaeological potential.

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

- Part Eight concludes this Final Submission.

PART TWO: THE PROJECT IS NECESSARY AND JUSTIFIED

12. This Part discusses how the Project is necessary and justified, as FEI is required by regulation and must adopt industry standard practice to mitigate the potential for rupture of the 29 Transmission due to external corrosion. This part is organized around the following key points:

(a) The 29 Transmission Laterals are susceptible to failure by rupture due to external corrosion that is undetectable using current practices.

(b) FEI is obligated under the OGAA to take to measures to monitor, and to mitigate or eliminate, hazards that can lead to failure of the 29 Transmission Laterals, and as prudent operator must adopt industry standard practices to manage corrosion.

(c) A quantitative risk assessment would not change the need for the Project and cannot relieve FEI of its obligation to undertake the Project.

(d) The Project cannot be safely deferred.

13. FEI submits that the BCUC should determine that the Project is needed and justified to mitigate the potential for the 29 Transmission Laterals to fail by rupture due to corrosion, consistent with FEI's regulatory obligations under CSA Z662 and industry standard practice.

A. The 29 Transmission Laterals Are Susceptible to Failure by Rupture due to External Corrosion

14. FEI's engineering team's assessment is that the 29 Transmission Laterals are susceptible to failure by rupture due to external corrosion that in some cases is undetectable by FEI's current integrity management practices for these pipelines. As discussed below, this assessment is based on industry standard knowledge about the nature of corrosion and its occurrence on pipelines, and the limits of above-ground survey techniques to detect it.

(a) Corrosion Is the Leading Cause of Pipeline Failure

15. Metal loss due to corrosion is the leading cause of pipeline failure.[13] For example, the BC OGC 2016 Annual Report identifies corrosion metal loss as the leading cause of pipeline failures from 2011 to 2016.[14]

16. Corrosion is the gradual deterioration of metal that results from a reaction with the environment, and which changes the iron contained in pipe to iron oxide (rust).[15] FEI's pipelines are subject to the hazard of "external" corrosion, meaning corrosion on the outside of the pipe.[16] If left untreated, the gradual deterioration can continue unabated until the pipeline fails. External corrosion is a "time-dependent" hazard because, once initiated, it can grow over time in extent and depth leading to pipeline failure.[17]

17. External corrosion can occur anywhere on a pipeline for numerous reasons, such that its occurrence is random and site-specific.[18] Corrosion can occur on pipelines of any age,[19] coating,[20] or method of construction.[21] Mr. Balmer explained as follows:[22]

> …the pipeline industry has experienced corrosion failures on lines that have been one-year old, all the way to very old pipelines. So it's the corrosion rate that would dictate when a failure would occur, and corrosion rates can vary over a wide range. So, it doesn't necessarily imply that the oldest pipelines are the ones that are most likely to have a failure.
>
> …we've seen corrosion on a cross-section of our pipelines…through our in-line inspection program. So from pipelines installed in the '50s and '60s all the way to more modern pipelines we have evidence of corrosion on our system.

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[13] Exhibit B-1, p. 18; Evidence of Bryan Balmer, Transcript, p. 50, lines 2-3.

[14] Exhibit B-1, Appendix C.

[15] Exhibit B-5, CEC IR 1.6.1. Evidence of Bryan Balmer, Transcript, pp. 49-50.

[16] Exhibit B-5, CEC IR 1.14.1. Corrosion on the inside of the pipe is not a hazard for FEI's pipelines.

[17] Exhibit B-5, CEC IR 1.6.1.

[18] Evidence of Bryan Balmer, Transcript, pp. 49-50.

[19] Evidence of Bryan Balmer, Transcript p. 47.

[20] Evidence of Bryan Balmer, Transcript, p. 48;

[21] Exhibit B-20, CEC IR 3.44.1.

[22] Evidence of Bryan Balmer, Transcript p. 47 and p. 50.

18. In short, external corrosion is a well-known hazard that can lead to failure of FEI's pipelines.[23]

(b) Techniques to Prevent and Detect Corrosion Are Limited by Cathodic Protection Shielding

19. As required by the CSA Z662 standard,[24] FEI's Integrity Management Program includes the management of the hazard of external corrosion on FEI's pipelines.[25] As described below, FEI has proactive management techniques to prevent corrosion, and strategies for detecting, assessing and monitoring the condition of its pipelines. However, these techniques and strategies have known limitations due to cathodic protection shielding ("CP shielding").

20. FEI's proactive external corrosion management consists of the use of external pipeline coatings and cathodic protection (sometimes referred to as "CP"). Cathodic protection is the application of an electrical current to the pipeline to minimize the natural corrosion tendency of buried steel. Cathodic protection provides a secondary defence where imperfections in the pipeline coating may exist.[26] Mr. Chernikhowsky explained as follows at the workshop:[27]

> So, by Code, the pipeline industry uses two methods to prevent external corrosion. The first is pipeline coatings, and the second is cathodic protection, or CP. Now, coatings are an external barrier on the pipeline, and it is to prevent electrolyte, typically water, from contacting the metal of the pipe wall and causing corrosion. But coatings aren't perfect. Sometimes there is damaged areas, or small holes. The technical term is a "holiday." And so we use CP, cathodic protection, to prevent corrosion from occurring where there are gaps in the coating. We impress a small electric current on the pipeline, and at any location where there is no coating, the electric coating effectively reverses the electrochemical reaction that causes corrosion. Normally we are able to detect defects in that coating by conducting above ground CP surveys, where we detect the electrical current leaking into the surrounding soil. That is part of the practice that we refer to in the application as external corrosion direct assessment, or ECDA.

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[23] Exhibit B-1, p. 18.

[24] FEI is required to have an integrity management program for its pipelines that complies with the CSA Z662 standard pursuant to the *Pipeline Regulation,* under the OGAA.

[25] Exhibit B-1, p. 62.

[26] Exhibit B-1, p. 18.

[27] Transcript, pp. 23-24.

21. As the 29 Transmission Laterals are not currently capable of being in-line inspected, FEI's current strategy for detecting, assessing and monitoring the condition of these pipelines is external corrosion direct assessment (or "ECDA").[28] External corrosion direct assessment employs above-ground cathodic protection surveys and coating evaluations, supplemented with integrity digs where warranted to evaluate asset condition.[29]

22. Even if cathodic protection is applied to a pipeline, corrosion can still occur due to CP shielding. CP shielding is where the cathodic protection current is prevented from reaching the pipeline steel, due to situations such as the presence of disbonded pipe coatings, large rocks, or foreign structures.[30] Furthermore, external corrosion direct assessment cannot detect corrosion in areas of CP shielding.[31] Mr. Chernikhowsky explained:[32]

> Unfortunately, for some of our pipelines, especially older ones, the coating can fail in such a way that the CP current is unable to reach the pipe wall to protect it. And we call this phenomenon CP shielding. But, and this is a very important point, when CP shielding occurs, we are unable to detect both the coating and CP failures, and so external corrosion can continue unabated and persist for an extended period, potentially resulting in a rupture.

23. CP shielding is known to occur on FEI's system. In fact, of the 318 integrity digs conducted on FEI's transmission and lateral pipelines between 2015 and 2018, 232 showed evidence of active corrosion on cathodically protected pipe.[33] As these digs sites were on pipelines with a range of ages and coating types, it is probable that active corrosion is also present on the 29 Transmission Laterals due to CP shielding.

24. Furthermore, conducting random integrity digs - to expose a portion of the pipe and visually inspect it for corrosion - is not a reliable way to detect corrosion over the 400 km of pipeline that are the subject of the Project. As discussed at length at the workshop, corrosion can occur randomly on any spot along the approximately 400 km over which the 29

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28 As described in the Application, Exhibit B-1, p. 21, FEI carries out a modified version of ECDA.

29 Exhibit B-1, p. 20-21.

30 Exhibit B-1, 18. Also see Exhibit B-5, CEC IR 1.4.9 and Exhibit B-13, 2.38.1.

31 Exhibit B-1, p. 21.

32 Evidence of Mr. Chernikhowsky, Transcript, p. 24.

33 Exhibit B-1, p. 18; Exhibit B-2, BCUC IR 1.4.1; Transcript, p. 29.

Transmission Laterals span,[34] and information from an integrity dig at one location cannot be used to predict the occurrence of corrosion on any other location.[35] In the absence of in-line inspection, the only way to determine the extent of corrosion on the 29 Transmission Laterals, would be to dig them all up and visually inspect them, which would have higher impacts and costs than the Project itself.[36]

25. Similarly, the information from the in-line inspection on other pipelines cannot be used to infer where corrosion is occurring on the 29 Transmission Laterals. Mr. Chernikhowsky explained:[37]

> And so the problem is the fact that we found corrosion caused by CP shielding on one pipe tells us nothing about where it could be occurring in another pipeline. So if we go back to our pipeline where we found a location of external corrosion that was detected by ILI but could not be detected using ECDA, for example a rock embedded in the coating, the same scenario could be causing corrosion on another pipeline, but we simply don't know where.
>
> …
>
> And, in other words, the causes of external corrosion on one pipeline can inform us of the nature of corrosion that can occur on another pipeline, but the location of external corrosion on one pipeline tells us nothing about the location or frequency where it could be occurring in another pipeline. The two pipelines might even have a similar design and construction, have been installed at the same time, but all it takes is some gravel or small boulder, for example, in the back fill of one location of pipeline B and an undetectable external corrosion could be occurring.
>
> …
>
> We do know that we've seen undetectable external corrosion on other FEI pipelines of similar construction. And so we have reason to believe that it is also occurring on the 29 transmission laterals. And fortunately, in the case of external corrosion we now have viable industry accepted solutions for the 29 transmission laterals. And those are the three presented in the application.

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[34] Evidence of Mr. Chernikhowsky, Transcript p. 13.

[35] Evidence of Mr. Chernikhowsky, Transcript, pp. 34; Evidence of Mr. Wayne Bryce, Transcript, pp. 51 - 54. Exhibit B-10, BCUC IR 2.36.1

[36] Transcript, Evidence of Mr. Chernikhowsky, p. 13

[37] Transcript, p. 33 and 34.

26. In summary, due to CP shielding FEI is currently unable to detect all instances of external corrosion on the 29 Transmission Laterals.

(c) Transmission Pipelines Operating over 30 Percent of SMYS Can Fail by Rupture

27. As the 29 Transmission Laterals operate at stress levels greater than 30 percent of the specified minimum yield strength (SMYS) of the pipe, they are susceptible to failure by rupture, which would be a sudden and uncontrolled release of natural gas. A failure by rupture is contrasted with a failure by leak, which FEI can manage through other integrity mitigation activities, including odourization which enables early leak detection.[38]

28. As explained in the Application, 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 would have a potential to leak.[39] FEI explained:[40]

> A pipeline's potential to fail by rupture due to corrosion can be determined by comparing the pipeline's operating hoop stress to the SMYS of the pipe. The operating hoop stress of a pipeline is the force per unit area exerted in the circumferential direction of the pipe wall due to the internal pressure of the fluid in the piping. The yield strength of a pipe is the level of stress where the pipe begins to permanently deform (yield). The SMYS of a pipe is the minimum yield strength prescribed by the specification or standard to which a material is manufactured.

29. Most importantly, the threshold of 30 percent for the ratio of a pipeline's operating hoop stress as compared to the SMYS of the pipe has been adopted by the CSA Z662 standard for Oil & Gas Pipeline Systems.[41] Section 3(1)(a) of the *Pipeline Regulation* requires that pipelines in BC be designed, constructed, operated, and maintained in accordance with the CSA Z662 standard. As stated by JANA: "General industry consensus and confirmed by the CSA

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38 Exhibit B-1, p. 19.

39 Exhibit B-1, p. 19.

40 Exhibit B-1, p. 19.

41 Exhibit B-1, p. 19.

Z662-19 Clause 12.1.1 and Clause 12.10.3.3 is that pipelines operating below 30 percent of SMYS will fail by leak rather than rupture..."[42]

30. FEI has filed extensive evidence in its Application[43], IR responses,[44] and the workshop[45] supporting the 30 percent of SMYS threshold. For example, FEI has explained the relationship between failure pressure, failure mode, and has shown that the range of defect lengths and depths on FEI's system would not cause rupture of a pipeline operating under 30 percent of SMYS.[46] FEI has also provided research articles that support the threshold:

(a) The 2004 ASME International Pipeline Conference Paper entitled "A Review of the Time Dependent Behaviour of Line Pipe Steel" indicates that full scale tests on part-wall (e.g., a corrosion defect that has not penetrated through the full thickness of the pipe) and through-wall defects (e.g. a corrosion defect that has penetrated through the full thickness of the pipe) showed that it is very unlikely that a part-wall defect will fail as a rupture at a stress level less than 30 percent.[47]

(b) "Leak versus Rupture Considerations for Steel Low-Stress Pipelines", Gas Research Institute Final Report No-00/0232, 2001, states: "Given the results generated, the leak to rupture transition for corrosion defects in the low-wall-stress pipeline system can be taken as 30 percent of SMYS, a value that is conservative in comparison with in-service incidents."

31. JANA, a recognized industry pipeline expert, has also provided oral and written evidence supporting the threshold, explaining it at length.[48] JANA confirmed that a review of the NEB incident database for incidents from 2009 – 2018 did not reveal any ruptures on pipelines operating below 30 percent of SMYS.[49]

32. As the 30 percent of SMYS threshold for rupture is embedded in CSA Z662, the threshold is not only accepted industry knowledge, but is part of the legal regulations by which

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42 Exhibit B-18, BCUC IR 3.65.2.

43 Exhibit B-1, p. 19.

44 Exhibit B-2, BCUC IR 1.9.1.

45 Transcript, p. 61 and pp. 65-67.

46 Exhibit B-18, BCUC IR 3.63.3.

47 Exhibit B-1, p. 19.

48 Transcript, pp. 61, 63-64; Exhibit B-18, BCUC IR 3.65.1 and 2.36.1.

49 Exhibit B-18, BCUC IR 3.65.2.

FEI must manage the integrity of its pipelines. The threshold is not only supported by substantial and detailed expert evidence in this proceeding, but is enshrined in the law of the Province.

(d) Consequences of Transmission Pipeline Rupture Can Be Significant

33. The rupture of any of the 29 Transmission Laterals could have significant and unacceptable consequences. The potentially significant safety, reliability, environmental and regulatory consequences that could be caused by a rupture were described as follows:[50]

- Safety Consequences: If the gas ignites, there can be significant safety impacts beyond the immediate area surrounding the pipeline. An ignited release can result in potential harm due to the ensuing fire and resulting thermal effects on people and property.

- Reliability Consequences: Many of the 29 Transmission Laterals are single feed supply to many of the municipalities in the interior British Columbia regions collectively comprising approximately 167 thousand FEI customers. A pipeline rupture would result in loss of supply to end-use customers with economic consequences for residential, commercial and industrial customers.

- Environmental Consequences: The environmental consequences 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 BC OGC. In addition, the release of gas by rupture would result in major on-site equipment failure and hence 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, FEI and the BC OGC considers that a failure by rupture of its natural gas pipelines to be a significant incident and not acceptable performance within its integrity management program.[51]

34. To ensure that the gravity of these potential consequences is understood, FEI provided descriptions of actual ruptures experienced in North America,[52] which have resulted in property damage and loss of life. FEI illustrated at the workshop that consequences of this nature could

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[50] Exhibit B-1, pp. 19-20; Exhibit B-4, CEC IR 1.3.2.

[51] Exhibit B-1, pp. 19-20.

[52] Exhibit B-5, CEC IR 1.3.2.

also result from a rupture of the 29 Transmission Laterals.[53] The forest destruction resulting from the recent rupture of the Enbridge pipeline in BC was used to illustrate the potential environmental consequences.[54] Further, as an example of the potential economic impacts to FEI's customers, FEI estimated that an outage of the Kelowna 1 Lateral could result in economic consequences in the range of $20 million.[55]

35. As is clear from these illustrations and examples, pipeline ruptures are for good reason unacceptable to FEI, the BC OGC and the industry in general. The significance of these consequences warrants substantial and meaningful action to prevent them from occurring, which includes undertaking the integrity management solutions proposed by FEI through the Project.

36. In summary, FEI's assessment of the 29 Transmission Laterals is that:[56]

- external corrosion is a known hazard to FEI's pipelines and the leading cause of transmission pipeline failures in BC;
- CP shielding is a known phenomenon and FEI has extensive evidence that it is occurring on its pipelines;
- FEI's status quo method to detect corrosion on the 29 Transmission Laterals will not detect corrosion where CP shielding is occurring;
- there is a potential for transmission pipeline rupture due to external corrosion; and
- rupture could result in significant consequences.

37. Given the nature of the risk, and the potential consequences of a rupture, no further classification of the risk is necessary to justify the Project. The Project is needed to mitigate the potential failure by rupture of the 29 Transmission Laterals.

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53 Exhibit B-16, Slides 4, 5 and 6. Transcript, pp. 10-12.

54 Exhibit B-16, Slides 4, 5 and 6. Transcript, pp. 10-12.

55 Exhibit B-4, CEC IR 1.3.2.

56 Exhibit B-18, BCUC IR 3.64.1.

B. FEI is Obligated by Code to Prevent Failure by Rupture and as a Prudent Operator Must Adopt Industry Standard Practices

38. FEI is obligated to undertake the Project pursuant to the OGAA, *Pipeline Regulation* and CSA Z662, which together comprise the legal requirements for the safe operation of transmission pipelines in BC. The high-level legal requirement in Section 37(1)(a) of the OGAA is to "prevent spillage". Section 3(1)(a) of the *Pipeline Regulation,* issued under the OGAA, requires FEI to follow the CSA Z662 standard, which, in essence, prescribes how FEI can meet its obligation to "prevent spillage". Section 7(1) of the *Pipeline Regulation* also requires FEI to have, and operate in accordance with, a pipeline integrity management program that complies with CSA Z662 and Annex N of CSA Z662.

39. As discussed in Part Two of this Final Submission, CSA Z662 incorporates the threshold of 30 percent of SMYS. In short, the requirements under CSA Z662 are more strict for pipelines that operate at or above 30 percent of SMYS. As described below, for pipelines operating at or greater than 30 percent of SMYS, CSA Z662 requires FEI to take measures to monitor, and to mitigate or eliminate, hazards that can lead to failure. As technology and industry standard practice has evolved, measures are available to monitor, and to mitigate or eliminate, the potential for external corrosion to lead to failure. FEI must therefore adopt these practices, which it is proposing to do through the Project.

40. FEI provided the relevant sections of CSA Z662 that show the stricter requirements for pipelines operating above 30 percent of SMYS.[57] For gas pipelines operating at less than 30 percent of SMYS, Clause 12.10.3.3 of CSA Z662 applies. This clause states:[58]

> Leak management shall be subject to the following requirements: …
>
> (c) Upon discovery, all leaks shall be immediately assessed and documented by competent personnel in accordance with the company's established guidelines to determine if a hazard exists. (…)

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[57] Exhibit B-2, BCUC IR 1.9.1; Exhibit B-4, BCOAPO IR 1.2.1.

[58] Exhibit B-4, BCOAPO IR 1.2.1, Clause 10.3.1, CAN/CSA Z662-15 – Oil and Gas Pipeline Systems. © 2015 Canadian Standard Association.

> (d) Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they are not suitable in service, they shall be replaced, reconditioned, or abandoned."

41. This clause indicates that it is appropriate for an operator of a gas distribution system to wait for an occurrence of leaks on its system prior to implementing a significant condition monitoring program (such as a regular in-line inspection program) or mitigation (replacement, reconditioning, or abandonment).

42. For gas pipelines operating at or greater than 30 percent of SMYS, however, CSA Z662-15 Clause 10.3.1 requires higher integrity management actions, namely, to monitor, and to mitigate or eliminate, hazards that can lead to failure. It states:[59]

> The pipeline system integrity management program required by Clause 3.2 shall include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data.

43. Consistent with the above, FEI's Integrity Management Program – Pipelines (IMP-P) currently follows a hazard management approach, as recognized by Clause N.8.3 (b) of the CSA Z662 standard:

> Where hazards that might lead to failure or damage incidents are identified, the operating company shall…implement and document measures for monitoring conditions that could lead to an incident with significant consequences and eliminate or mitigate such conditions….

44. As indicated above, FEI must monitor, and mitigate or eliminate, conditions that can lead to an incident with significant consequences.

45. As discussed in Part Two, section A above, external corrosion is a known hazard on FEI's pipelines that can lead to failure. Further, given that the 29 Transmission Laterals operate above 30 percent of SMYS, they may fail by rupture, which can have significant consequences.

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59 Exhibit B-4, BCOAPO IR 1.2.1, Clause 3.2, CAN/CSA Z662-15 – Oil and Gas Pipeline Systems. © 2015 Canadian Standard Association.

FEI is therefore obligated by CSA Z662 to adopt strategies that give it the capability to monitor, and mitigate or eliminate, the hazard of external corrosion on the laterals.[60]

46. As also discussed in Part Two, section A above, FEI's current management strategies for the 29 Transmission Laterals, including ECDA, do not provide the capability to monitor, and mitigate or eliminate, external corrosion where CP shielding is occurring. As an alternative to ECDA,[61] in-line inspection has become the accepted industry practice for managing corrosion of transmission pipelines and mitigating their potential for rupture. In-line inspection enables an operator to identify imperfections, and to focus pipeline rehabilitation efforts to specific locations. In-line inspection also provides pipeline wall condition data (including changes over time) that can inform long-term asset planning. For this reason, FEI in-line inspects the majority of its transmission pipelines. It has proven highly effective in detecting and sizing potentially injurious pipe imperfections. Due to asset management practices at the time, the 29 Transmission Laterals were not designed and constructed with in-line inspection capabilities. However, in-line inspection is now technically feasible for natural gas pipelines down to a nominal pipeline size of 6 inches.[62]

47. The diagram below illustrates the progression of FEI's and industry's integrity management practices for different pipe sizes operating above 30 percent of SMYS.

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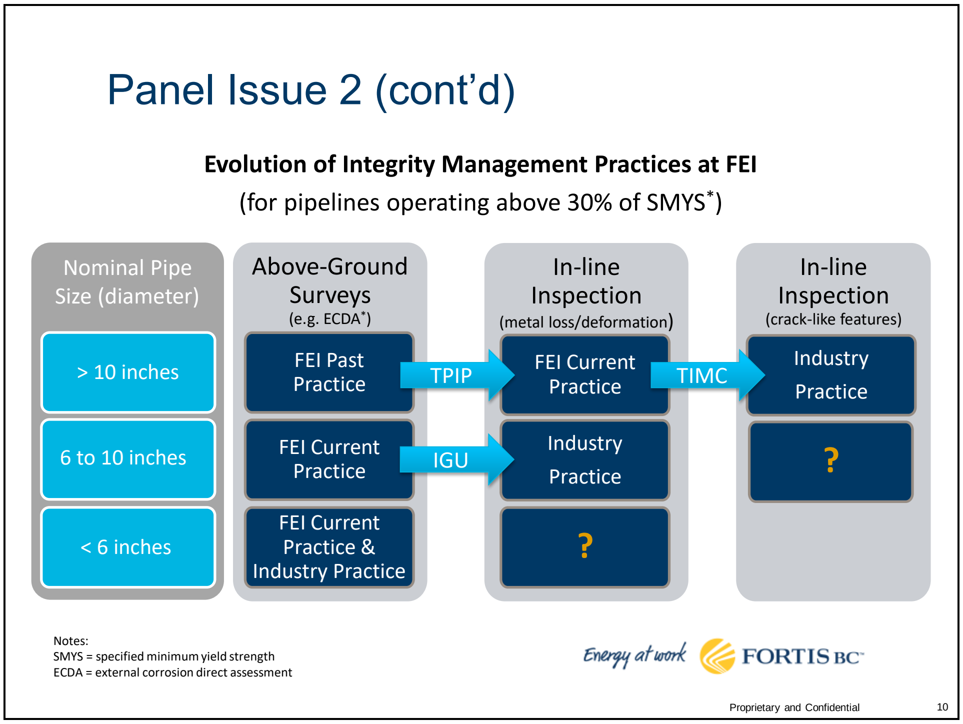
60 Exhibit B-4, BCOAPO IR 1.2.1.

61 As described in the Application, p. 21, FEI carries out a modified version of ECDA.

62 Exhibit B-1, p. 1; Exhibit B-2, BCUC IRs 1.1.1 and 1.6.7; and Exhibit B-10, BCUC IRs 2.35.11 and 2.36.2.



48. Mr. Chernikhowsky explained the above diagram as follows:[63]

> So, for pipelines greater than 10-inches, many years ago we used techniques such as above-ground surveys to manage all of our transmission pipelines. And one of those above-ground survey techniques is referred to as external corrosion direct assessment, or ECDA. Over time, due to concerns we had less confidence in those techniques, and so we moved, transmission pipeline integrity project -- program, or TPIP.
>
> As industry practice continues to evolve, we are also evaluating new tools to detect cracking in our large pipelines, and that will be the subject of a future CPCN application, the TIMC.
>
> Similarly, for 6 to 10-inch pipelines, given our reduced confidence in our above-ground surveys, and changes in industry practice, we are now proposing to move to ILI to remain consistent with other operators. That's the IGU project, and it's a good example of continual improvement that results from the evolution in integrity management practices in the industry. Over time it becomes a regulatory expectation. It is a demonstration of due diligence, adopting a proven, industry accepted practice to decrease the risk of a failure is prudent and reasonable.

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63 Transcript, pp. 16-17.

49. As explained by Mr. Chernikhowsky, FEI's larger diameter pipelines (greater than 10 inches) are already managed through in-line inspection. Now, as in-line inspection technology has become available for smaller diameter pipelines (between 6 and 10 inches), industry has adopted that technology and it has become the expected standard. The Project will bring FEI's 6 to 10 inch pipelines into line with this practice and standard, just as FEI's previously-approved TPIP brought FEI's larger diameter pipelines in-line with this standard.[64]

50. As such, FEI's system-wide corrosion monitoring approach is shown in the table below.[65]

Asset Class	Diameter Range (NPS)	System-Wide Corrosion Monitoring Approach
Transmission pipelines operating at greater than or equal to 30% SMYS	6 and greater	In-line inspection
Transmission pipelines operating at greater than or equal to 30% SMYS	Less than 6	Modified ECDA; however, FEI will continue to monitor technology available for mitigating the potential for rupture failure on these lines
Pipelines operating at less than 30% SMYS	Any	Integrity-related activities such as CP Surveillance, visual observation any time the pipeline may be exposed during its lifecycle, and leak detection are performed. A significant condition monitoring program (such as a regular in-line inspection program) or mitigation (replacement, reconditioning, or abandonment) is only planned upon an occurrence of a relevant leak history.

51. Consistent with the approach above, the Project will make each of the 29 Transmission Laterals either ILI-capable consistent with FEI's other pipelines 6 inches or greater, or reduce the operating stress below 30 percent of SMYS such that they are not subject to the same potential for rupture and regulatory requirements under CSA Z662. As a prudent operator, FEI must undertake the Project to comply with its regulatory obligations and manage the 29 Transmission Laterals consistent with industry standard practice.

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64 Exhibit B-4, BCOAPO IR 1.1.6.

65 Exhibit B-5, CEC IR 1.1.3.

C. A Quantitative Risk Assessment Is Not Required to Assess the Need for the Project

52. A quantitative risk assessment (or "QRA") is not required to justify the Project. Moreover, a quantitative risk assessment could not relieve FEI of its obligation as a prudent operator to take industry standard approaches to mitigate the potential for these pipelines to fail by rupture, consistent with the CSA Z662 standard.

53. JANA, who is currently working with FEI to conduct a quantitative risk assessment, was unequivocal that a quantitative risk assessment would not change the need for the Project:[66]

> JANA's technical opinion is that a QRA would not change the justification for the IGU project as the project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP). As detailed in "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", it is JANA's opinion that a QRA is not required to justify investments required to meet Compliance- and ISP-driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA.

54. In its report entitled "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", JANA recommends a decision making process for managing pipeline assets. The first two steps explain why a quantitative risk assessment is not needed for a project driven by compliance or industry standard practice, as follows:[67]

> Pipeline & Standards *(Compliance)*
>
> - Compliance activities must be completed regardless of the results of any QRA. If AM or IM investments are required by regulation and standards, these must be conducted and a QRA is not required for justification as these are not asset risk-based decisions.
>
> Industry Standard Practice *(ISP)*
>
> - For industries where there are potential hazards that can impact the public, such as the gas pipeline industry, Industry Standard Practice (ISP) becomes a prudent benchmark for pipeline operators and their regulators. Operators are otherwise at risk of being found negligent if lawsuits result from an accident. IM practices should, therefore, be consistent with evolving industry standard practice.

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[66] Exhibit B-10, BCUC IR 2.36.1

[67] Exhibit B-10, Attachment 36.1B.

55. FEI added the following discussion of why a quantitative risk assessment is not required for the Project: [68]

> As risk is equal to the probability of an undesirable event occurring, multiplied by the consequences of that event occurring, a quantitative risk assessment requires reasonable estimates of both the probability and potential consequences of failure. Estimating the probability of a failure is typically more challenging than estimating the potential consequences because the estimated failure rates for transmission pipelines vary depending on the availability of high-quality asset condition data. If only low-quality, less-granular data is available, then assumptions must be made during the risk estimation, which is reflected in larger uncertainty or error bounds around the estimated failure rates.
>
> In the case of the 29 Transmission Laterals within the scope of the IGU Project, the available asset condition data is low quality and not granular. This is due in particular to the absence of ILI data. There is also limited failure history available to differentiate between each of the 29 Transmission Laterals. While the 29 Transmission Laterals represent a range of pipeline ages, the attribute of age, in isolation, is not an accurate method for differentiating failure likelihood.
>
> The estimated failure rates for the 29 Transmission Laterals would therefore likely be based on generic historic failure rates developed from publicly-available failure databases (for pipeline systems that may or may not accurately reflect FEI's operating conditions), and would need to be caveated with large uncertainty or error bounds. For this reason, the failure rates would not have a sufficient level of accuracy to enable a meaningful differentiation of estimated quantitative risk of failure over the 5-year implementation timeline of the IGU Project.

56. As illustrated by the examples of the quantitative risk analysis in response to BCUC IR 3.66.3, the risk profile of a pipeline without ILI data is very limited – it is essentially a flat line, meaning there is virtually no identifiable variation in risk estimation across the entire pipeline. This is because of the lack of high quality granular asset condition data. In comparison, the risk profile for the pipeline with ILI data is varied over the length of the pipeline.[69] This underscores that a quantitative risk assessment of the 29 Transmission Laterals would not be helpful for the Project, and would not be able to relieve FEI of the need to carry out the Project.

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[68] Exhibit B-10, BCUC IR 2.36.1

[69] Exhibit B-18, BCUC IR 3.66.3.

57. At the workshop, Mr. Chernikhowsky explained why a quantitative risk assessment is not needed for the Project, as follows:[70]

> There appears to be a misconception that a quantitative risk assessment is always superior, or perhaps can be used to override decisions. For example, those made for the 29 transmission laterals through a qualitative assessment. This is not the case.
>
> For decades, FEI has relied on professional judgment to determine the need for work such as the IGU project. Our professional engineers consider factors such as equipment condition data, industry practice, current codes and regulations, and many more to determine both the capital and maintenance work that is needed for our system. That is still a valid process, and the BC OGC has not indicated otherwise.
>
> So, where does a QRA fit into this picture? So, fundamentally a QRA is used for two purposes; to prioritize complex work, and activities that could not otherwise be addressed all at the same time, or to identify otherwise unknown risk, which we call "interacting threats" that we might not otherwise have been aware of due to their complexity. ...
>
> As a prudent operator, FEI proposes projects as needed to ensure we meet our legal and regulatory obligations, to maintain consistency with industry standard practice of other pipeline operators in Canada, and to strive for FEI's goal of zero incidents of significant consequences. And so it is for those reasons that we have proposed the IGU project at this time.
>
> And this is why we say that a segment-by-segment risk analysis or quantitative risk assessment is not needed. So, in response to panel issue one, compliance with industry practice and compliance with codes and regulations are the only drivers necessary to support the need for the IGU project.
>
> And to put it another way, the BC OGC has directed FEI to conduct a segment-by-segment risk assessment to assure that we have not missed anything, not to allow us to defer addressing known risks.

58. Further to Mr. Chernikhowsky's point in the quote above, in its letter dated August 26, 2019, the BC OGC confirms that it supports FEI taking action to address its known integrity

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[70] Transcript, pp. 13-16.

concerns and to ensure that it meets its requirements as a permit holder under the OGAA.[71] In its letter, the BC OGC quotes Clause 10.3.2.2 of the CSA Z662 standard, which states:

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

59. Further to the above, FEI's engineering team has assessed that the 29 Transmission Laterals are susceptible to failure due to external corrosion and that current measures to prevent such failure are not acceptable due to CP shielding.[72] As such, FEI is obligated to undertake the Project to implement measures to prevent such failure or operate them under conditions determined by an engineering assessment to be acceptable. A quantitative risk assessment cannot relieve FEI of that obligation.

D. The Project Cannot Be Safely Deferred

60. As set out in the sections above, the Project must be carried out for FEI to be compliant with its regulatory obligations, to be consistent with industry practice, and to mitigate the potential failure by rupture due to the well-known hazard of corrosion, which is the leading cause of pipeline failure in the province. Delaying the ability to detect this hazard on the 29 Transmission Laterals will increase the likelihood of a pipeline rupture.[73]

61. Furthermore, proven and commercialized in-line inspection technology exists for the mitigation of external corrosion on these pipelines, or alternative options are available to reduce the operating stress levels to mitigate the consequences of failure (i.e. leak rather than rupture). These alternatives are the industry standard approach to preventing failure by rupture due to corrosion. As prudent operator, FEI must adopt such industry standard approaches. As the Project is necessary to maintain compliance with FEI's regulatory

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71 Exhibit B-18, Attachment 67.1.

72 Exhibit B-18, BCUC IR 3.64.1, Table 1.

73 Exhibit B-13, CEC IR 2.40.1

obligations and consistency with industry standard practice, FEI submits that there is no safe period of time over which the Project could be deferred. [74]

PART THREE: ALTERNATIVES ANALYSIS IDENTIFIED COST-EFFECTIVE ALTERNATIVES

62. In this Part, FEI describes the alternatives analysis for the Project, as set out in section 4 and Appendix I of the Application. This Part is organized around the following key points:

(a) FEI conducted a careful and detailed analysis of all identified alternatives using a comprehensive decision-making framework;

(b) FEI chose the most cost-effective alternatives for each lateral; and,

(c) A quantitative risk assessment would not change the alternatives analysis.

63. FEI submits that the BCUC should determine that FEI has correctly identified the most cost-effective alternative for each of the laterals within scope of the Project.

A. FEI Analyzed All Identified Alternatives Using a Comprehensive Framework

(a) FEI Considered the Relevant Alternatives

64. FEI analysed seven alternative integrity management solutions that could meet the Project's objective to mitigate the potential for rupture failure due to corrosion on the 29 Transmission Laterals. Each of these alternatives are described in detail in the Application, and are as follows:

- Status Quo: Modified External Corrosion Direct Assessment (Modified ECDA);
- Pipeline exposure and re-coat (PLE);
- Hydrostatic testing program (HSTP);
- Pressure regulating station (PRS);
- In-line inspection (ILI);
- Pipeline replacement (PLR); and
- Robotic Inspection (ROB).

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[74] Exhibit B-2, BCUC IR 1.3.1; Exhibit B-13, CEC IR 2.40.1; and Exhibit B-20, CEC IR 3.45.5.

65. No other alternatives were raised during the course of the proceeding.

(b) FEI Used a Comprehensive Alternatives Evaluation Methodology

66. FEI applied a weighted-scoring methodology to evaluate the performance of each alternative in relation to three sets of evaluation criteria. In some cases, where the laterals and loops were physically interconnected with crossover connections and are operated as a system, the selected alternative was evaluated for compatibility with the whole system. In addition to the weighted-score computed for each alternative, FEI internal subject matter experts validated the highest scoring alternative for each lateral.

67. FEI used the following evaluation criteria to evaluate the alternatives, each of which is described in detail in the Application:

1. Integrity and Asset Management Capability:
    a. Prevention of Ruptures;
    b. Prevention of Leaks;
    c. Proactive Asset Management; and
    d. Technical Certainty.
2. Project Execution and Lifecycle Operation:
    a. Environmental;
    b. Lands & ROW;
    c. Consultation and Engagement Complexity;
    d. Operational Complexity;
    e. System Capacity & Customer Impacts; and
    f. Project Execution Certainty.
3. Financial:
    a. Present Value (PV) of Incremental Annual Revenue Requirement (over 66 years).

68. FEI created a scoring (between 0-5) and weighting system for each of the criteria, which is described in detail in section 4.3.2 and Appendix I of the Application. The weightings applied when scoring the alternatives are detailed in Tables 4-1 to 4-4 of the Application.[75]

69. The financial evaluation for the alternatives analysis compared the present value of the incremental revenue requirement relative to the alternative with the lowest present value of incremental revenue requirement. For a fair comparison, future incremental sustainment capital and operating expenditures over the 66-year analysis period for each alternative was included.[76]

70. FEI also incorporated subject matter expertise where appropriate. Where scores for alternatives were close, FEI's internal subject matter experts met to review and determine the preferred alternative for each lateral, considering factors such as site-specific knowledge of the pipeline environment.

71. FEI's analysis of each alternative is described in the detailed evaluation of each lateral in Appendix I of the Application. FEI submits that its alternatives analysis framework was detailed and robust, and provided a reasonable and appropriate basis on which to analyze the alternatives.

(c) FEI Correctly Considered the Physical Lives of the Pipelines to be Indefinite

72. FEI's financial evaluation of the alternatives correctly considered that the physical lives of the laterals are indefinite, rather than include the cost of pipeline replacement at the end of the pipeline's financial life as suggested in information requests.[77] FEI explained that there is no indication at this time that any of the 29 Transmission Laterals are approaching the end of their useful life.[78] Further, the physical age of the pipeline is not a threat to integrity and age

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[75] FEI provided further discussion of how it determined the weightings in response to BCUC IRs 1.18.1 and 1.18.2, Exhibit B-2.

[76] Exhibit B-1, p. 35.

[77] Exhibit B-2, BCUC IR 1.1.1; Exhibit B-10, BCUC IR 2.45.1.

[78] Exhibit B-10, BCUC IR 2.45.1.

itself does not cause pipeline failure.[79] As stated by Mr. Chernikhowsky, pipelines do not "wear out". The fundamental degradation mechanism of steel pipelines is corrosion. If the utility manages corrosion, the pipeline itself can last indefinitely.[80]

73. JANA confirmed FEI's analysis, stating:[81]

> Based on JANA's awareness of transmission pipeline historical failure data and available industry literature, JANA's opinion is that there is not currently an industry-recognized finite lifetime for a well-maintained and appropriately assessed pipeline. This opinion is based on:
>
> - Industry studies demonstrating that there is no time-dependent degradation of the fundamental properties of the steels used in natural gas pipelines. The strength properties of steel pipelines, provided time-dependent threats such as corrosion are managed, will not degrade over time.
>
> - An industry study, based on analysis of historical transmission pipeline failures, that concluded that "a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely". That is, with proper application of Integrity Management approaches, there is no recognized finite lifetime for a transmission pipeline.
>
> - JANA's analysis of PHMSA historical transmission pipeline failure data that confirms the analysis conducted in the above-referenced study. [Footnotes excluded.]

74. The key findings of the industry study referenced by JANA provide convincing evidence:[82]

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79 Exhibit B-2, BCUC IR 1.1.1.

80 Transcript, p. 46.

81 Exhibit B-10, BCUC IR 2.45.1.

82 Exhibit B-10, BCUC IR 2.45.1.

KEY FINDINGS

Ultimately, the safety of a particular natural gas transmission pipeline is not necessarily related to its age because:

1. 85% of pipeline incidents reported to PHMSA from 2002-2009 occurred irrespective of the age of the pipeline, with just 15% related in some way to the age of the pipeline.
2. The properties of the steels which comprise natural gas pipelines do not change with time; that is, pipe does not "wear out."
3. The fitness of a pipeline for service does not necessarily expire at some point in time.
4. The integrity of those pipelines for which the fitness for service may degrade with the passage of time can be assessed periodically. Timely repairs - and other mitigation efforts - based on those assessments will ensure the pipeline's continued fitness for service.
5. A well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely.

75. The opinion of JANA and the key findings of the report cited above support FEI's view that the common understanding in the industry is that natural gas transmission pipelines can have an indefinite useful life.[83]

B. FEI Appropriately Screened Out Alternatives Based on Technical and Financial Criteria

76. Using the methodology described above, FEI first evaluated the technical merits of the alternatives to screen out those that did not accomplish the objective of the Project to mitigate the potential for rupture due to corrosion. FEI then considered whether the alternatives were proven and commercialized, other technical criteria such as Project execution and lifecycle operation factors, and high level cost estimates to determine alternatives that should be screened out. The outcome of this process resulted in four alternatives being screened out, as well as the PRS being screened out as an alternative for some of the laterals. While discussed in detail in the Application and responses to information requests, the results are summarized in the sections below.

[83] Exhibit B-10, BCUC IR 2.45.1.

(a) Status Quo: Modified ECDA Screened Out Based on Inability to Achieve Project Objective

77. As discussed in detail in Part Two of this Final Submission, where CP shielding is occurring, Modified ECDA will not detect sites that may be experiencing active corrosion. As FEI's inspection of its system has shown that active corrosion has occurred on cathodically-protected pipe due to CP shielding, Modified ECDA is not an acceptable means to manage the potential for corrosion-related rupture to the 29 Transmission Laterals over the long term. This alternative does not achieve the primary objective of the Project which is to mitigate the potential for rupture due to external corrosion. Therefore, the Status Quo was screened out on a technical basis.

(b) Robotic Inspection (ROB) Screened Out Based on Readiness

78. This alternative involves the use of robotic ILI tools that are self-propelled and can be inserted into pipelines through stopple fittings.[84] As discussed in Appendix I of the Application, FEI is monitoring the evolution of ILI tools, and there are potentially feasible application of these tools, such as for the inspection of short pipeline segments.[85] However, robotic ILI tools were ruled out:

- robotic ILI tools are not proven and commercialized;
- the technology is not available for pipe sizes of NPS 6 (168mm) and FEI is only aware of a single vendor providing this service for larger pipe sizes;
- pipeline inspection intervals are limited to 450 meter lengths before requiring a battery recharge; and
- excavations and tool retrieval required at each recharge point every time the robotic tool is run make its use complex and undesirable from a lifecycle operation perspective, in terms of impact to the environment, Indigenous communities, and stakeholders.[86]

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84 Exhibit B-1, p. 32.

85 Exhibit B-1, Appendix I, pp. 2-3; Exhibit B-5, CEC IR 1.21.1.4.

86 Exhibit B-1, p. 32 and 39. Exhibit B-5, CEC IR 1.19 to 1.21. Exhibit B-6, CEC Confidential IR 1.4.1 and 1.4.1.1.

79. As a result, the ROB alternative was screened out as not feasible and was not considered further in the evaluation process.

(c) Pressure Regulating Station (PRS) Screened Out for Some Laterals Based on Capacity Limitations

80. The PRS alternative involves installation of a pressure regulating station to lower the operating stress of pipeline to below 30% of SMYS.[87] PRS was not viable for some laterals due to capacity limitations of some systems. By reducing the operating pressure of the pipeline, the capacity available to customers will change. Laterals where a PRS would impact existing firm customers or interruptible customer operations or prevent additions of new customers to the lateral were not considered candidates for the PRS alternative.[88] FEI provided a detailed discussion of its methodology and calculations for determining the impacts of PRS for each of the laterals,[89] and analysis of potential days of curtailment of customers.[90] FEI's analysis confirms that PRS is not feasible for some laterals, but is feasible for others, as summarized in Table 4-5 of the Application. As a result, the PRS alternative was appropriately screened out for the laterals where there are capacity limitations.

(d) Pipeline Exposure and Re-coat (PLE) Screened based on Technical and Financial Analysis

81. The PLE alternative provides a high confidence method of assessing pipeline condition by exposing the pipe, making necessary repairs, applying a modern coating and utilizing Modified ECDA.[91] However, PLE would not improve proactive asset management.[92] In addition, PLE was rated the lowest for Project execution and lifecycle due to complex Project execution and larger impact to the environment, Indigenous communities and stakeholders as a result of the need to excavate the entire length of the lateral. The exposure of the full length of the pipeline for a detailed inspection, recoating and making any necessary repairs is a

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87 Exhibit B-1, p. 30.

88 Exhibit B-1, pp. 39-40, as updated by Exhibit B-1-1.

89 Exhibit B-2, BCUC IR 1.14.1, 14.2 and 14.3.

90 Exhibit B-13, CEC IR 2.37.6.2.

91 Exhibit B-1, p. 30 and 42.

92 Exhibit B-1, Table 4-6, p. 41.

significant and complex undertaking not commonly employed by transmission pipeline operators.[93] The financial analysis showed that PLE would cost as much as, or more than, other alternatives that had more favourable technical scores.[94] PLE was therefore eliminated as an alternative.

(e) Hydrostatic Testing Program (HSTP) Screened based on Technical and Financial Analysis

82. The HSTP alternative involves periodically taking the pipeline out of service and subjecting it to a hydrostatic test (i.e. filling the line with water to a pressure above the expected maximum operating pressure). In the event of a failed test (i.e. loss of pressure during the test), the leaking section(s) of pipe would be located, excavated, cut-out and replaced, and then the entire test section subjected to a subsequent hydrostatic test.[95] The HSTP alternative would achieve the objective of preventing rupture by subjecting the lateral to a pressure test. However, it suffered from substantial drawbacks, including:[96]

- It does not provide any capability of proactive asset management. It does not provide any pipe condition data and therefore cannot identify defects that have potential to fail, provide any leak prevention capability, or predict failure in between the hydrostatic test intervals,
- Using hydrostatic testing for ongoing management of corrosion results in issues related to water disposal (i.e. environmental-related challenges), required service outages, and LNG supplementation.
- Hydrostatic testing can activate manufacturing flaws in seam welds into time-dependent flaws.
- HSTP requires the line to be shut down, which limits this alternative to laterals with redundant looping or laterals with practical means of supporting downstream customers.
- It is cost prohibitive compared to other alternatives that were either equal or superior in their technical performance.

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93 Exhibit B-1, pp. 40-41.

94 Exhibit B-1, p. 43, as corrected by Exhibit B-1-1.

95 Exhibit B-1, p. 30.

96 Exhibit B-1, pp. 41-43. Exhibit B-2, BCUC IR 1.15.1; Exhibit B-10, BCUC IR 2.47.1.

83. As a result, FEI did not pursue the HSTP alternative further in the evaluation process.

C. FEI Chose the Most Cost-Effective of the Remaining, Feasible Alternative for Each Lateral

84. FEI evaluated each of the remaining three feasible alternatives (PRS, ILI and PLR) for each lateral using the evaluation methodology described above. The detailed scoring is provided in Appendix I of the Application. The following sections summarize the findings of the alternative evaluation process, with a focus on key topics raised in the proceeding.

(a) PRS is the Lowest Cost and was Selected Where Viable

85. The PRS alternative involves the installation of a pressure regulating station to lower the operating pressure, and consequently the operating stress of a pipeline to below 30 percent of SMYS. The PRS alternative has the smallest ground disturbance footprint of all the alternatives given that the impact would be limited to the station site itself, reducing the potential impact to the environment, Indigenous communities and stakeholders. PRS is only feasible for laterals that have sufficient capacity to meet forecast demand when pressure is below 30 percent of SMYS.[97]

86. As PRS meets the objectives of the Project at the lowest cost, with the added benefit of limited ground disturbance and community impacts, it was the preferred alternative where viable in all cases except for two. In the two cases where PRS was viable but not selected as the preferred alternative, PLR was chosen as PLR had a higher overall score, as it was financially comparable or more cost effective, with better integrity and asset management capability benefits.[98]

PRS Is Lower Risk and Considerably less Expensive

87. Where PRS was chosen as the preferred alternative, it had more favourable scores for Project Execution and Lifecycle Operation (PRS scored from 4.3 to 4.6, compared to 2.8 to 3.7 for ILI and PLR). This reflects the more limited scope and ground disturbance of building a

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[97] Exhibit B-1, p. 30.

[98] Exhibit B-1, p. 45, as corrected by Exhibit B-1-1.

single pressure regulating station, compared to replacing the entire pipeline or retrofitting the pipeline for ILI. In the response to BCUC IR 3.73.1, FEI provides a detailed description of the higher construction risk of ILI and PLR for each of the laterals where PRS is the preferred alternative. As shown in Table 1 of that response, where the construction risk for PRS was rated low for 10 laterals and medium for 4, the construction risk for ILI or PLR is medium for 6 laterals, and high for 8.[99]

88. The selection of PRS for the 14 laterals is also considerably less expensive than the next best alternative of ILI or PLR. If PRS was rejected as a preferred alternative, the capital cost of the Project would increase by approximately $140 million, with the present value over 66 years increasing by approximately $152 million (i.e., $420 million with PRS versus $572 million without PRS). Consequently, the estimated delivery rate impact of the Project would increase to 5.83 percent from 4.30 percent. These cost and rate impacts are likely underestimated as the contingency and management reserve percentages for the Project would need to increase due to the increased project construction risk associated with ILI and PLR.[100]

PRS Is the Most Cost-Effective Alternative for the Elkview Lateral

89. FEI selected PRS as the preferred alternative for Elkview since it has a smaller immediate delivery rate impact, a comparable revenue requirement over the 66-year analysis period, less ground disturbance over a smaller construction footprint than PLR, and less archaeological and environmental impacts.[101]

90. There was a very small difference of $46 thousand in the present value of revenue requirement over a 66-year analysis period between PLR and PRS ($5.831 million and $5.877 million, respectively). However, the capital cost of the PLR alternative is $1.239 million more

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[99] Exhibit B-18, BCUC IR 3.73.1.

[100] Exhibit B-18, BCUC IR 3.70.1. As stated in this response, should the BCUC approve ILI or PLR instead of PRS for any of the 14 laterals, FEI would need to perform the necessary development work required to generate revised contingency and management reserve figures that are consistent with the approved project construction risk.

[101] Exhibit B-2, BCUC IR 1.18.4 and 1.18.5.

expensive than PRS ($6.588 million and $5.319 million, respectively). Therefore, PRS has a smaller immediate delivery rate impact in the early years due to a lower initial capital cost.[102]

91. Further, the ground disturbance for the PRS would be significantly less than would be required to replace the 1.5 kilometre Elkview lateral. For this reason, the PRS option also requires less coordination over Teck Coal lands and will have less archaeological and environmental impacts.[103]

92. As a result, PRS is the most cost-effective alternative for the Elkview Lateral considering all of the relevant factors.

PRS is an Effective and Industry Standard Approach to Preventing Failure by Rupture

93. FEI confirmed the validity of PRS as an effective approach to preventing failure by rupture. As discussed in detail above in Part Two of this Final Submission, the rupture threat associated with external corrosion is appropriately mitigated if a pipeline is operating below 30 percent of SMYS. This is reflected in CSA Z662-19 and is consistent with generally accepted industry practice, and is supported by third party studies and JANA's expert opinion.[104]

94. JANA confirmed that operating below 30 percent of SMYS is accepted mitigation regardless of age of the pipeline:[105]

> …Operating below 30 percent SMYS reduces the risk for pre-1970s pipe versus its current risk when operating above 30 percent SMYS and implementation of an operating stress reduction below 30 percent SMYS is an accepted mitigation for all transmission pipelines regardless of their year of installation. While the general industry consensus is that reduction of pressure to below 30 percent SMYS will lead to leak rather rupture is not limited to specific pipeline construction dates, there is the potential that older pipelines could be more susceptible to the rare circumstances that could lead to rupture below 30 percent SMYS .

[102] Exhibit B-2, BCUC IR 1.18.4.

[103] Exhibit B-2, BCUC IR 1.18.4; Exhibit B-10, BCUC IR 2.48.3.

[104] Exhibit B-18, BCUC IR 3.70.1.

[105] Exhibit B-18, BCUC IR 3.70.2.

95. JANA also confirmed that the rupture of a pipeline operating under 30 percent of SMYS is a rare occurrence in the industry, and, where it has occurred, it has not been due to external corrosion:[106]

> An analysis of the NEB incident records for 2008-2018 did not reveal any reported ruptures <30 percent SMYS for Canadian pipelines. A 2013 report by Rosenfeld provides a summary of ruptures on pipelines below 30 percent SMYS for the US. There are 11 reported gas pipeline ruptures. None of these occurred due to external corrosion on the body of the pipe. Four occurred due to selective seam corrosion.
>
> For mitigation of the identified external corrosion threat, a reduction to below 30 percent SMYS is considered an effective approach as it will result in a pinhole leak and not rupture (consistent with industry experience). In the case of selective seam corrosion, a reduction to below 30 percent SMYS will also significantly reduce, though not fully eliminate the potential for rupture. This is because the leak rupture boundary is dependant on the operating pressure and the length and depth of the defect, and only very long and deep selective seam corrosion defects (which are very rare) would provide a situation in which rupture would occur and shorter more shallow defects would lead to leaks. This is why this type of rupture is a rare occurrence below 30 percent SMYS (with only four identified occurrences in the Rosenfeld report).

96. While the residual risk that remains with pipelines that are operated below 30 percent of SMYS can never be zero, operation of a pipeline below 30 percent of SMYS addresses the primary hazard of external corrosion, and other hazards.[107] This is a risk mitigation solution adopted by the pipeline industry and aligns with the CSA Z662 standard as a threshold differentiating between two classifications of assets that warrant substantively different approaches to their life-cycle integrity management.[108]

PRS Is the Most Cost-Effective Alternative for 14 Laterals

97. In summary, PRS is the most cost-effective feasible alternative for 14 of the 29 laterals. If PRS were not chosen as the preferred alternative as proposed, both the total project cost and

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[106] Exhibit B-18, BCUC IR 3.70.3.

[107] Exhibit B-10, BCUC IR 2.41.1.

[108] Exhibit B-18, BCUC IR 3.70.2.

the construction risk for each of the 14 laterals would be considerably higher.[109] These higher risks and costs are not justified as the PRS provides an effective and industry accepted approach to mitigating the potential for failure by rupture.

(b) In-line Inspection (ILI) is More Cost Effective for Longer Pipelines

98. The ILI alternative requires retrofitting an existing pipeline to accommodate its inspection by removing any obstructions that may impede the clear passage of the ILI tool. FEI would install a launcher and receiver barrel and associated valves and piping. Following the retrofit, FEI would verify that obstructions were removed by using a gauge plate or simple caliper tool. ILI inspections involve the insertion of a data collection device (commonly referred to as an ILI tool or pig) inside the operating pipeline to obtain indirect measurement of imperfections that may adversely affect its integrity. ILI data collection occurs on a recurring cycle (typically 5 to 7 years). A detailed description of FEI's ILI process is included within Appendix E. ILI is highly regarded by operators as the data enables rehabilitation efforts to be focused on specific locations. ILI also enables proactive asset management by providing pipeline wall condition data (including changes over time) that can inform long-term asset planning.[110]

99. FEI's alternatives analysis found that ILI was the most cost-effective alternative for longer pipelines, where PRS was not feasible. For most laterals, ILI and PLR both scored comparably under the technical criteria of preventing rupture and leaks; however, ILI has an advantage of providing better proactive asset management capability. The ILI and PLR alternatives also had comparable Project execution and lifecycle operation technical criteria scores, with slight differences depending on the terrain and potential challenges from working on Indigenous community lands, archaeological sites, environmental concerns and crossings. In terms of financial evaluation, the difference in scores between ILI and PLR for each lateral depended mostly on the length of the lateral.[111] Therefore, for the longer laterals, especially those longer than 4 kilometres, the PV of incremental revenue requirement and rate impacts

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109 Exhibit B-18, BCUC IR 3.73.1 and 3.73.1.1.

110 Exhibit B-1, p. 30-31.

111 Exhibit B-1, pp. 45-46.

were much higher for PLR when compared to ILI for the same lateral. ILI was therefore selected for all of the laterals that were longer due to having a lower rate impact along with providing better proactive asset management capability.[112] FEI's choice of ILI as an alternative was generally not questioned during the proceeding.

(c) Pipeline Replacement (PLR) is more Cost Effective for Shorter Pipelines

100. The PLR alternative involves replacing the existing pipeline with a new pipeline constructed to current standards of design, material selection, and construction. The new pipeline would be designed with the needed pipe grade and wall thickness to serve existing and future load at a stress level of less than 30 percent of SMYS, which mitigates the potential for rupture due to corrosion.[113] Pipeline replacement would involve disturbing the ground within FEI's right-of-way ("ROW") to install the new pipe, which could result in disruption to Indigenous communities and surrounding landowners and other stakeholders. FEI would require land acquisition for construction and working space, as the original pipeline will need to remain in-service until the installation of the replacement pipeline is completed.[114]

101. The pipeline would be constructed so that it could accommodate future ILI capability with limited retrofits (namely, the installation of pig launcher and receiver barrels). FEI did not include in this alternative the financial cost of installing the launcher and receiver barrels to enable ILI, or the cost of performing ILI on these new pipelines, because constructing the pipeline to operate below 30 percent of SMYS eliminates the need for a regular in-line inspection program.[115]

102. For the shorter laterals, especially those less than 4 kilometres in length, the PV of incremental revenue requirements and rate impacts were typically less for PLR when compared to ILI for the same lateral. The PLR alternative for the shorter laterals thus achieved the highest financial score. This financial score combined with a comparable technical score, resulted in

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112 Exhibit B-1, p. 46.

113 Exhibit B-1, p. 31. Exhibit B-10, BCUC IR 2.43.1 and 2.43.2.

114 Exhibit B-1, pp. 31-32.

115 Exhibit B-2, BCUC IR 1.17.1, 1. 17.1.1.1, and 1.17.1.1.2.

the highest overall score for the PLR alternative as compared to the ILI alternative and was therefore selected as the preferred alternative.[116]

D. A Quantitative Risk Assessment Would not Change the Alternatives Analysis

103. FEI and JANA both confirm that at quantitative risk analysis would not change the analysis of alternatives for the Project. As explained in Part Two of this Final Submission, the available asset condition data on the 29 Transmission Laterals is low quality and not granular due to the absence of ILI data, limited failure history, and that age is not an accurate method for differentiating failure likelihood. The estimated failure rates for the 29 Transmission Laterals would therefore not have a sufficient level of accuracy to enable a meaningful differentiation of estimated quantitative risk of failure to have any meaningful impact. Therefore, FEI's selection of alternatives for the Project on the basis of the evaluation criteria would not be altered or benefit from the results of a QRA.[117]

104. JANA agreed with FEI's assessment, stating:[118]

> It is JANA's opinion that a QRA would not lead to a different mitigation action for external corrosion. Pipeline replacement, ILI and pressure reduction below 30 percent SMYS are effective mitigations for the external corrosion threat. The factors leading to selection of PRS installation over ILI or PLR would not be changed by a QRA.

105. Therefore, FEI's alternatives analysis could not be changed by a quantitative risk analysis. FEI submits that its alternatives analysis was appropriate and carefully conducted and has resulted in the most cost-effective alternative for each lateral within scope of the Project.

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

106. This Part of this Final Submission addresses topics explored relating to the Project description, costs, accounting treatment and rate impacts. The evidence supporting the Project scope, cost estimate, and schedule is detailed and complete, and demonstrates that FEI has

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[116] Exhibit B-1, p. 46.

[117] Exhibit B-10, BCUC IR 2.36.1.

[118] Exhibit B-18, BCUC IR 3.66.5.

prudently and carefully scoped and estimated the costs for the Project. FEI provided detailed information on the Project in section 5 of the Application, including:

- The basis of design and engineering, basis of the AACE Class 3 cost estimate, and the construction, installation and commissioning plans for the ILI, PRS, and PLR components;
- The Project cost estimate, including risk assessment, contingency and reserve determination;
- Construction verification and commissioning along with a summary schedule;
- Project resourcing requirements;
- Identified Project impacts; and
- Required permits and approvals.

107. In section 6 of the Application, FEI provided a breakdown of the Project cost by lateral, summarized financial analysis and details of accounting treatment and rate impact. FEI also set out its requested approval of deferral account treatment of the Application and Preliminary Stage Development Costs for the Project.

108. Sections 5 and 6 of the Application are supported by extensive reports, including Stantec's Front-End Engineering Design (FEED) reports in Appendix J, the technical description of the proposed work for each lateral in Appendix K, Stantec's Risk Report in Appendix L-1, Bramcon and Validation Estimating Consulting reports supporting the Monte Carlo analysis for the contingency and reserve in Appendices L-2 and L-3, and the detailed schedule in Appendix M.

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

(a) FEI's cost estimate for the Project meets the requirements of the CPCN guidelines, is robust and appropriately includes a contingency and management reserve;

(b) A quantitative risk assessment could not be used to improve the prioritization of the work; and

(c) FEI's proposed amortization period for the requested deferral account is reasonable and appropriate.

A. FEI's Cost Estimate for the Project Meets the Requirements of the CPCN Guidelines, Is Robust and Appropriately Includes a Contingency and Management Reserve

110. The Project capital cost estimate is forecast to be $320.853 million in 2018 dollars or $360.193 million in as-spent dollars (including AFUDC of $15.327 million). FEI, in conjunction with Stantec,[119] developed the Project cost estimate for each lateral in accordance to AACE 18R-97 Class 3 specifications as required by the CPCN Guidelines.[120] The project cost estimate includes contingency of 17 percent as well as a management reserve of 11 percent. The capital cost estimate with the management reserve approximates a P70 confidence level.[121]

111. In addition to the substantial information included in the Application, FEI responded to information requests that provided further detailed information on the Project and cost estimate:

- FEI explained in detailed why, due to the mostly rural setting of the IGU Project, the nature of the work, operating agreements in place with the municipalities, and ongoing efforts to work collaboratively with municipalities, FEI is unlikely to encounter issues similar to those experienced with the City of Coquitlam on the LMIPSU Project.[122]
- FEI explained that the budget for engagement activities is line with industry best practices, and that it considers there to be a high likelihood that the budget for engagement activities will be adequate. FEI's Community and Indigenous Relations group has been supporting operational work similar to the Project in the Interior region for a number of years, and the engagement with Indigenous communities has been positive to date.[123]
- FEI explained that the Project will not trigger any of the criteria for a major environmental assessment.[124]

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[119] See Exhibit B-6, CEC Confidential IR 1.1.2 for a description of Stantec's role in the Project.

[120] Exhibit B-1, pp. 64 and 84.

[121] Exhibit B-1, p. 66, as corrected by Exhibit B-1-1.

[122] Exhibit B-3, BCUC Confidential IR 1.1.8.

[123] Exhibit B-11, BCUC Confidential IR 2.14.3.

[124] Exhibit B-3, BCUC Confidential IR 1.1.2.

- FEI provided further details on the risks identified in the risk register, including how it intends to manage risks such as labour availability[125] and specific risks related to particular laterals.[126]

- FEI explained the technical, design and other challenges which may be encountered if stopple fittings are to be re-used, justifying its assumption that all stopple split tee fittings will be unusable.[127]

- FEI provided a detailed breakdown and description of its estimated Land Rights costs.[128] FEI provided further explanations of the basis for its estimated costs for fee simple acquisition,[129] temporary work space,[130] encroachments,[131] use of third party lands/alternative access,[132] ROW acquisition,[133] surveys,[134] land agent fees,[135] and consultant fees.[136] FEI further provided more detailed information on these estimated costs for particular laterals.[137]

- FEI provided a detailed breakdown and description of the Owners Costs.[138]

- FEI explained how, consistent with AACE 44R guidelines, Validation Consulting developed the contingency fund for the Project as a whole, rather than particular estimates for each of the risks identified in the Stantec Risk Report.[139]

- FEI explained that the Stantec risk adjusted P10, P50 and P90 estimates for the Project do not directly or indirectly consider the variation in the number of elbows and bends. Rather, the variation in quantities of bends is related to a variation in scope and is accounted for by the introduction of a management reserve as discussed in the Application.[140]

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125 Exhibit B-3, BCUC Confidential IR 1.1.1.

126 Exhibit B-3, BCUC Confidential IR 1.4.1 to 11.1.

127 Exhibit B-6, CEC Confidential IR 1.5.1.

128 Exhibit B-3, BCUC Confidential IR 1.2.5.

129 Exhibit B-11, BCUC Confidential IR 2.16.1.

130 Exhibit B-11, BCUC Confidential IR 2.16.2.

131 Exhibit B-11, BCUC Confidential IR 2.16.5.

132 Exhibit B-11, BCUC Confidential IR 2.16.7.

133 Exhibit B-11, BCUC Confidential IR 2.16.11 to 16.12.1.

134 Exhibit B-11, BCUC Confidential IR 2.16.14.

135 Exhibit B-11, BCUC Confidential IR 2.16.15 and 16.16.

136 Exhibit B-11, BCUC Confidential IR 2.16.17.

137 Exhibit B-3, BCUC Confidential IR 1.2.2 and 2.3; Exhibit B-11, BCUC Confidential IR 2.16.3, 2.16.3.1, 16.4, 16.8.1, 16.9, 16.10, 16.13

138 Exhibit B-3, BCUC Confidential IR 1.13.1.

139 Exhibit B-3, BCUC Confidential IR 1.3.5.

140 Exhibit B-6, CEC Confidential IR 1.9.1.

- FEI explained that the ‘Probable Elbows’ in the chart on page 6 of the Bramcon Report is a single point estimate of the number of bends that require replacement based on a representative field sampling of known locations. This estimate was determined using information gathered from the field sampling where some sites were selected, excavated, and the pipe bends were examined. To convert the single point estimate and establish a range of possibilities, a Monte Carlo Simulation (MCS) statistical analysis was run to calculate multiple scenarios. The MCS uses the single point data for each lateral on page 6 of the Bramcon Report to compute a range of possible outcomes, as shown on page 7 of the Bramcon Report, to establish a total number of bends that are likely to require replacement.[141]

- FEI explained that the selection of the 75 percent probability in the Bramcon report is based on Bramcon’s expert judgement and experience in conducting similar types of analysis to arrive at an estimated quantity for estimating purposes.[142] The 75 percent probability recommended is a prediction of the expected number of bends (200) that is likely to be encountered can be considered a “best estimate”, meaning a reasonably accurate estimate based on the knowledge and information available.[143]

112. As details of the above responses are confidential, FEI does not address them further in this submission. FEI submits that in all cases FEI’s responses demonstrate that FEI’s cost estimate is reasonable and FEI has accounted for and is managing project risks carefully and appropriately.

113. FEI’s responses to information requests also demonstrate that FEI’s inclusion of a management reserve is reasonable and appropriate. FEI’s contingency and management reserve is based on the Project’s risk profile and accounts for possible scope changes or unknown future events which cannot be anticipated and which were not quantified in the risk register.[144] For the purposes of its contingency and management reserve, FEI used the output of the Monte Carlo Simulation conducted by Validation Estimating as it was indicative of the

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141 Exhibit B-6, CEC Confidential IR 1.11.1.

142 Exhibit B-6, CEC Confidential IR 1.10.1.

143 Exhibit B-14, Confidential CEC IR 2.12.1.

144 Exhibit B-1, pp. 69-72.

range of risk outcomes for the Project over a multi-year timeframe.[145] FEI summarized its recommend contingency and management reserve as follows:[146]

> As a result, FEI's recommended contingency for the Project is 17 percent at the P50 confidence level. Contingency is typically expected to be spent and is used as an allocation for risks that are known and likely to be encountered during Project execution with a relatively high level of certainty. For a project that is executed over multiple years, however, there are certain risks that can occur but are relatively unknown and have a low likelihood of occurrence but the occurrence of which could have high consequences. To account for these risks, typically called system risks, and based on the analysis conducted by Validation Estimating, the addition of a management reserve of 11 percent (totalling 28 percent together with contingency) is considered prudent. This additional 11 percent approximates the P70 confidence level estimated by Validation Estimating.

114. FEI's inclusion of a management reserve along with contingency in the Project cost estimate is reasonable and necessary:

(a) It accounts for possible scope changes or unknown future events which cannot be anticipated and which were not quantified in the risk register. Due to the vintage of the 29 Transmission Laterals there is uncertainty with the number of restrictive bends. All restrictive bends must be replaced to allow ILI tool passage, even if they exceed the number allowed for in the Project cost estimate. There is no certainty as to location or type of bends but the likelihood of finding more than the estimated quantity is relatively low to medium considering the analysis done to date. Moreover, for a multi-year project implementation schedule, some additional risks in addition to those identified in the risk register, for which the occurrence and/or effect are unknown, could likely occur. The uncertainty and risks associated with the estimated quantity, along with the unknown risks over the multi-year implementation period, are expected to have a low to medium likelihood of occurrence but the consequences could be high.[147]

(b) It is consistent with AACE recommended practices. As per the AACE definitions, contingency is an amount added to an estimate as an allowance for known risks that are likely to occur during the implementation of a project and is the uncertainty associated with an estimate for a defined scope of the Project. Some or all of the contingency amount is expected to be spent during project

[145] Validation Consulting's report is included as Appendix L-3 of the Application.

[146] Exhibit B-1, p. 72.

[147] Exhibit B-10, BCUC IR 2.49.1.

implementation. A management reserve, on the other hand, is an allowance for significant scope changes and/or unknown project related risks that have high consequence but a low likelihood of occurring that may materialize during project implementation.[148]

(c) It is consistent with the BCUC's 2015 CPCN Guidelines. Section 5(vi) of the Guidelines specifically contemplates the inclusion of reserves in addition to a contingency where a Monte Carlo analysis is used to model the amount of contingency included in the cost estimate.[149]

(d) It is consistent with practices used by other utilities in Canada, including BC Hydro,[150] Manitoba Hydro,[151] and FortisBC Inc.[152] In particular, the inclusion of a management reserve for potential additional scope due to work in underground pipelines is similar in principle to FortisBC Inc.'s Cora Linn Dam Spillway Gates CPCN which included a reserve due to potential additional scope for submerged components of the facility.[153]

115. The use of contingency and management reserve is in accordance with AACE recommended practices, and FEI's contingency and management reserve amounts appropriately reflect the project's specific attributes and the uncertainty and risks associated with the Project.

116. FEI submits that the Project cost estimate meets the requirements of the 2015 CPCN Guidelines, and is robust and reasonable.

B. A Quantitative Risk Assessment Could Not Be Used to Improve the Prioritization of the Work

117. FEI has prudently planned for the execution of the Project over a five-year period, using a phased, year-by-year approach where detailed design, planning and procurement activities

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148 Exhibit B-10, BCUC IR 2.49.1.

149 The 2015 CPCN Guidelines are available online at the following: https://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf

150 BC Hydro Ruskin Dam and Powerhouse Upgrade Project CPCN. https://www.bcuc.com/Documents/Proceedings/2011/DOC_27024_B-1_BCH-Ruskin-Dam-CPCN-Application.pdf

151 Manitoba Hydro's Capital Cost Estimate development for the Keeyask and Conawapa project http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/appendix_02_4_developing_the_keeyask_and_conawapa_capital_cost_estimates.pdf

152 FBC Replacement of the Corra Linn Dam Spillway Gates CPCN – page 61 of the Application

153 Exhibit B-2, BCUC IR 1.23.1; Exhibit B-10, BCUC IR 2.49.1.

will occur the year prior to the work being undertaken.[154] Taking into account FEI's obligations under the CSA Z662 standard and need to adopt industry standard practice as discussed above in Part Two of this submission, the planned 5-year implementation timeline for the Project is a reasonable period over which to achieve proactive mitigation of the potential for rupture of the 29 Transmission Laterals. In FEI's judgement, taking into account all the information available to it, and its legal and regulatory obligations, 5 years is a reasonable time over which to execute the IGU Project.[155]

118. FEI has appropriately developed the detailed schedule for the Project based on factors such as the regional distribution of the Project, capacity limitations including industrial customers' requirements, scheduling constraints (such as windows of time where work can be undertaken on the laterals), cost efficiencies by managing as a single project, operational constraints (such as working on an in-service line), and contractor and resource limitations. As discussed above, FEI has no information that indicates that there would be improvement from a safety or reliability perspective by prioritizing the laterals differently than currently planned.[156]

119. FEI does not have condition assessment or other information that would support the need to expedite or delay the project timeline. Based on the information available on the 29 Transmission Laterals, there is not a material difference in the integrity risk level of the laterals. All of the 29 Transmission Laterals are subject to the same potential for rupture due to external corrosion that may go undetected by FEI's current integrity management techniques. The available condition information does not provide any indication of systemic issues on any particular lateral. Given the information available, FEI's assessment is that it is appropriate to implement the proposed scope of the Project for all 29 Transmission Laterals proactively over a reasonable planning horizon.[157]

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[155] Exhibit B-2, BCUC IR 1.2.1 and 3.1.

[156] Exhibit B-2, BCUC IR 1.3.1.

[157] Exhibit B-2, BCUC IR 1.3.1.

120. As stated by FEI, given FEI's limited condition assessment information on the 29 Transmission Laterals due to lack of in-line inspection data, FEI's ability to prioritize amongst the laterals would be limited, even with a quantitative risk assessment.[158]

121. JANA confirmed FEI's views, stating:[159]

> JANA's technical opinion is that, given the short project timeline of five years for the IGU project, a QRA would not materially impact the timeline or scheduling of these activities. First, given that the justification for the IGU project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP), a QRA would not change the requirements for the IGU project. It is JANA's opinion that a QRA is not required to justify investments required to meet Compliance and ISP driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA. Second, given the short timeline of the project, it is JANA's opinion that scheduling and prioritization will be driven by logistical concerns and not risk given the small difference in risk reduction expected for conducting the work, for example, in Year 2 versus Year 3.

122. JANA further clarified that a quantitative risk assessment would not have been of use in assessing the Project had the work been scheduled over a longer period:[160]

> In JANA's opinion, no. The stated FEI need for conducting the IGU project is to meet the regulatory requirements of managing the identified corrosion threat. The need to address this threat and conduct the project would not be changed by a QRA. "The short project timeline" refers to the potential benefit of a QRA in assisting in the decision process for prioritization of the project sub-components. For a considerably longer timeframe project, e.g. 20 years, there could be benefit in a QRA for assessing prioritization of the project sub-components within the overall decision-making process.

123. FEI described why a quantitative risk assessment would not be sufficiently accurate to differentiate the risk of failure of the laterals to have an impact on the Project, as follows:[161]

> In the case of the 29 Transmission Laterals within the scope of the IGU Project, the available asset condition data is low quality and not granular. This is due in

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[158] Exhibit B-2, BCUC IR 1.3.1.

[159] Exhibit B-10, BCUC IR 2.36.1.

[160] Exhibit B-19, BCOAPO IR 3.3.1.

[161] Exhibit B-10, BCUC IR 2.36.1.

> particular to the absence of ILI data. There is also limited failure history available to differentiate between each of the 29 Transmission Laterals. While the 29 Transmission Laterals represent a range of pipeline ages, the attribute of age, in isolation, is not an accurate method for differentiating failure likelihood.
>
> The estimated failure rates for the 29 Transmission Laterals would therefore likely be based on generic historic failure rates developed from publicly-available failure databases (for pipeline systems that may or may not accurately reflect FEI's operating conditions), and would need to be caveated with large uncertainty or error bounds. For this reason, the failure rates would not have a sufficient level of accuracy to enable a meaningful differentiation of estimated quantitative risk of failure over the 5-year implementation timeline of the IGU Project.

124. In short, since the 29 Transmission Laterals are not capable of being in-line inspected, there is insufficient data to quantify the risk of rupture in a manner that would materially distinguish the risk of rupture amongst the laterals. Even if a more granular assessment of risk could be undertaken, a reprioritization of the work for the Project would not have a material benefit. This is because FEI has already planned to proceed with the Project as quickly as reasonably possible to address the risk of rupture due to undetectable external corrosion. Prioritizing the work on one or more of the 29 Transmission Laterals differently as compared to FEI's planned implementation of the IGU Project would not materially reduce the risk.[162]

C. FEI's Proposed Amortization Period for the Requested Deferral Account Is Reasonable and Appropriate

125. FEI is seeking approval of a new non-rate base deferral account, to be called the IGU Application and Preliminary Stage Development Costs Deferral Account. This account will capture the application and preliminary stage development costs of the Project. The Application costs include expenses for legal review, consultant costs, BCUC costs and BCUC-approved intervener costs, which FEI forecast based on a written hearing process with two rounds of information requests. The Preliminary Stage Development costs are related to expenses incurred by FEI internally and also for third-party consultants for feasibility evaluation, preliminary development and assessment of the potential design and alternatives as required to complete the Application. FEI proposes that the account attract FEI's weighted average cost

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[162] Exhibit B-12, BCOAPO IR 2.1.1

of capital until it enters rate base.[163] FEI's forecast balance in the account to the end of 2019 is presented in Table 6-5 of the Application. FEI will update the forecast balance for the account in its application to set rates for 2020.

126. FEI proposes to transfer the balance in the deferral account to rate base on January 1, 2020 and commence amortization over a three-year period.[164] While a 1 or 2 year amortization period may also be appropriate given the projected balance, FEI proposed a three-year amortization period primarily based on similar deferral accounts approved for recent CPCN applications. For example, BCUC Order C-2-14 for FEI's Muskwa River Crossing Project approved a deferral account with a three-year amortization period. As another example, BCUC Order C-11-15 for FEI's Lower Mainland Intermediate Pressure System Upgrade Project approved two separate deferral accounts for the Application and Project Development costs, both with a three-year amortization period.[165] As with these other accounts, a three-year amortization period reasonably spreads the projected balance in the account. FEI submits that its requested deferral account and associated accounting treatment is reasonable and appropriate.

[163] Exhibit B-1, pp. 86-87.

[164] Exhibit B-1, pp. 86-87.

[165] Exhibit B-2, BCUC IR 1.25.2.

PART FIVE: ENVIRONMENT AND ARCHAEOLOGY

127. The Project is expected to have minimal environmental and archaeological impact based on the environmental and archaeological assessments undertaken.[166]

128. The Environmental Overview Assessment of the Project completed by Hemmera Envirochem Inc., which is included as Attachment O of the Application, concludes that the environmental risk of the Project is low. The assessment also concludes that potential impacts can be mitigated through the implementation of standard best management practices. Further, impacts to construction timelines and costs as a result of encountering species at risk, fish habitat, or contaminated soil or groundwater can be minimized through additional pre-construction investigations.[167] These best management practices and mitigation measures, as described in Section 6 of the Environmental Overview Assessment report, will form part of the project's Environmental Management Plans.[168]

129. Stantec completed the Archeological Overview Assessment ("AOA") of the Project included as Appendix P of the Application. The AOA concluded that the majority of the expected Project footprint is considered to have low archaeological potential due to the amount of previous disturbance. The AOA recommended an Archaeological Impact Assessment ("AIA") for ground disturbance activities in areas identified as moderate or high potential.[169] The AIA will provide a detailed assessment to develop site specific mitigation strategies to offset any potential impacts associated with the Project. FEI requires permits under the Heritage Conservation Act to undertake detailed AIA activities, which FEI will obtain during the detailed engineering phase of the Project. Detailed archaeological specifications will be prepared as part of the Project's tendering process to ensure that contractors are aware of the Project's archaeological requirements under those permits.[170]

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166 Exhibit B-1, Section 7.

167 Exhibit B-1, pp. 89-90; Appendix O (included in electronic format only due to its size).

168 Exhibit B-10, BCUC IR 2.50.1.

169 Exhibit B-1, p. 98.

170 Exhibit B-1, p. 100.

130. In summary, based on the assessments undertaken for the Project, the Project is expected to have minimal environmental and archaeological impact.

PART SIX: PUBLIC CONSULTATION AND ENGAGEMENT WITH INDIGENOUS COMMUNITIES

131. This Part of this Final Submission discusses how FEI's public consultation and engagement with Indigenous communities has been sufficient, and that there have not been any significant issues or concerns raised with respect to the Project. FEI will be continuing to consult with the public and engage with Indigenous communities throughout the life of the Project.

A. Public Consultation Has Been Sufficient and Does Not Indicate Significant Concerns

132. As stated in the Application, FEI's main goals for public consultation are to: create a dialogue with interested parties, explain the need for the Project, present FEI's preferred alternatives for the Project, demonstrate the detailed assessment of alternatives, and inform interested parties of the factors that FEI must consider, including environmental impacts, constructability, and rate impacts resulting from the Project.[171]

133. Prior to starting consultation, FEI created a Communications and Consultation Plan to guide its public consultation.[172] The Communication and Consultation Plan outlines potential issues, lists stakeholders, and sets out the general approach to consultation with respect to the work on the 29 Transmission Laterals. FEI identified key issues, risks and impacts for each of the laterals, and then established three tiers (high, moderate and low) to characterize the potential issues and impacts associated with each lateral.[173] FEI then established tailored consultation approaches appropriate for each tier. FEI developed communication materials for consultation, including:[174]

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[171] Exhibit B-1, p. 102.

[172] Exhibit B-1, Appendix Q-1.

[173] Exhibit B-1, p.104.

[174] Exhibit B-1, pp. 106-107.

- A Project webpage on FEI's Talking Energy website platform. The webpage provides a high level overview of the Project, including detailed maps of where the 29 Transmission Laterals are located (Appendix Q-5).

- A list of key messages to help describe the Project in relatable terms. The messages include: the type of work that will be involved, where the work will take place and the proposed timing of the Project (Appendix Q-6).

- A Project email address and direct phone line to help better direct inquiries FEI receives about the Project. Both of the channels went live in June 2018 and will continue to be closely monitored throughout the Project.

- Paid advertisements, including digital advertising distributed Province wide and paid advertisements in local newspapers of impacted communities, published in August and September 2018 (Appendix Q-7).

- A bill insert (Appendix Q-8) was mailed to all customers in September 2018 to provide information about the Project. In the same month, e-billing customers received a link to a soft copy along with their emailed bill. An ad was also placed alongside the e-billing portal that over 360 thousand customers potentially saw when they paid their bills online (Appendix Q-9).

134. As described in detail in section 8.2.4 the Application, FEI's consultation activities included:

- Communication regarding the Project with the pertinent government agencies at the municipal and regional levels;

- Communication regarding the Project with directly impacted land owners, customers and local residents and businesses;

- Meetings, presentations and conversations with stakeholders; and

- Broad-based communications, such as paid media to inform the public where impacts are more substantial, which will occur during the construction phase.

135. FEI's consultation methods were tailored to each group, including residential customers, industrial customers and local governments, and included notifications through letters, bill inserts and advertisements, phone calls, numerous one-on-one meetings with government authorities and responses to requests for further information.

136. FEI has tracked issues or concerns raised and is committed to work with customers and stakeholders to address any outstanding items. Only three concerns have been expressed about the Project to date. The three issues or concerns, and FEI's responses, are as follows:[175]

(a) Public Consultation re Kenna Cartwright Park: The City of Kamloops had raised concerns about the pipeline replacement for KA1 LTL 168 that traverses Kenna Cartwright Park, a regularly used Municipal park in Kamloops. The City of Kamloops has requested public engagement and awareness about the Project.

Response: In addition to notification letters, stakeholder meetings and paid advertisements, FEI proposed an open house session for Kamloops residents prior to submission of the CPCN Application. Through engagement with the municipality, the City of Kamloops determined that it would be more effective to hold a public consultation session once more detailed information about the construction plans and schedule were known. FEI committed to follow up with the City of Kamloops to collaborate on rescheduling the session

(b) Legacies re Kenna Cartwright Park: The City of Kamloops requested proper restoration efforts with the addition of park benches and a gazebo. The City of Kamloops also wishes to be actively involved during the restoration phase.

Response: FEI's objective is to create these legacies as a part of the restoration commitment, and maintain open communication with the City of Kamloops during the restoration phase.

(c) North Star Rails to Trails: The City of Kimberley also expressed concern regarding the North Star Rails to Trails corridor, a 25-kilometre nature trail that connects the City of Kimberley to the City of Cranbrook. The City requested that the trail remain open during construction.

Response: FEI is aware of the concern, and will continue to work with the City of Kimberley through future meetings closer to the construction period. Before the Project begins, FEI will review impacts to the Rail to Trail nature trail and discuss plans to mitigate impacts with the District of Kimberley. It is FEI's preference that the trail remain open during construction.[176] As the Project gets closer to commencing, and detailed design is completed, FEI will have a better understanding of impacts to the trail and will work proactively with the City of Kimberley to minimize any disruptions.[177]

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[175] Exhibit B-1, p. 120-21.

[176] Exhibit B-2, Updated Table 8-2 in BCUC IR 1.32.2.

[177] Exhibit B-2, BCUC IR 1.32.5.

137. An updated Table 8-2 summarizing FEI's consultation with local governments to date is provided in response to BCUC IR 32.2.[178] FEI will continue to work collaboratively with the City of Kamloops, the City of Kimberly, and other municipalities, taking into account the community impact of the Project and, where applicable, in accordance with FEI's rights and obligations under its operating agreements with municipalities.[179]

138. FEI received five emails in response to its notification letters. Three of these emails were from stakeholders that wish to maintain open and active communication during construction to ensure any third party assets and/or business operations are unaffected. The fourth and fifth email were from residential customers inquiring about potential rate impacts of the Project, to which FEI replied with the requested information. [180]

139. FEI believes the low number of issues or concerns expressed is likely due to the overall rural landscape of the Project's intended construction work, low resident and business density on the gas line route, and the preferred alternative selected for each lateral.[181] As a result, the Project will have only minimal impacts to streets and public spaces. FEI explained as follows:[182]

(i) Retrofitting 11 laterals to provide in-line inspection capability (ILI): Short sections of gas line modifications may be required at road crossings and result in impacts to municipal roads at these locations. FEI will finalize at the detailed design stage which segments in road crossings will require modifications.

(ii) Construction of pressure regulating stations (PRS) on 14 laterals: The construction of a PRS requires tie-in locations that in some cases may extend into the road allowance and result in some impacts to the road. FEI will finalize these locations at the detailed design stage and will work collaboratively with the municipalities as the Project proceeds.

(iii) Replacement of 4 laterals with new pipe (PLR): Two of the laterals to be replaced are not located in municipal public spaces. The third lateral parallels an undeveloped road allowance and crosses two roads that will

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[178] Exhibit B-2.

[179] Exhibit B-3, BCUC Confidential IR 1.1.8.

[180] Exhibit B-1, p. 120-21.

[181] Exhibit B-3, BCUC Confidential IR 1.1.8.

[182] Exhibit B-3, BCUC Confidential IR 1.1.8.

> require disturbance of the roadway which may result in some traffic disruption. Approximately 90 percent of the fourth lateral that will be replaced is located in a municipal park (Kamloops 1 Lateral and Loop 168) where FEI has pre-existing statutory rights of way (SRW) for the existing gas lines which were registered on title prior to the lands becoming a municipal park. The remainder of this lateral is located on privately owned parcels. The replacement of this lateral will not involve the disturbance of roadway and result in traffic disruption. FEI is, however, aware of the impact the Project will have on the ability of the public to use certain portions of the municipal park during construction and is working collaboratively with the City of Kamloops to minimize these impacts. …FEI has an operating agreement with the City of Kamloops.

140. FEI submits that its communication plan and the public consultation activities to the time of filing the Application have been sufficient, appropriate and reasonable to meet the requirements of the CPCN Guidelines. FEI will continue to consult with stakeholders regarding construction timelines, construction spaces, plans on mitigating traffic disruptions (where applicable) and public safety. Further consultation will continue prior to and throughout construction to help inform local government and residences about construction activities in their area in an effort to minimize impacts. FEI will comply with all BC OGC permitting requirements, where applicable, which includes further Project notifications to key stakeholders prior to construction. FEI is dedicated to maintaining open dialogue and good relationships with businesses, landowners and local government throughout the various stages of construction and will work with them to minimize the impacts of the Project.[183]

B. Engagement with Indigenous Communities Has Been Sufficient and Does Not Indicate Significant Concerns

141. FEI has engaged Indigenous communities and leadership in the areas potentially impacted by the Project. FEI engaged early with Indigenous communities that may potentially be affected by the Project to provide information about the Project, describe any potential impacts, understand the interests in the area, and provide an opportunity for Indigenous communities to identify additional impacts and to give input on the Project. Engagement was initiated by notification letters, and then followed by face-to-face meetings as requested. In

[183] Exhibit B-2, BCUC IR 1.27.1.

many cases FEI was able to arrange for meetings with the communities. FEI also sent any requested information to the communities if available. For those requests that require greater detail than is currently available, FEI has committed to ongoing engagement through follow up meetings to share relevant information as it becomes available.[184]

142. In response to FEI's early engagement, a number of Indigenous communities expressed interest in working on the Project in some capacity. FEI has or will schedule follow up meetings with these communities as additional information around contracting and procurement becomes available. Some concerns such as those related to sensitive areas require additional, site specific information that is not available. FEI will continue to engage with those communities that have requested additional information with follow up meetings as the Project design becomes more certain.[185]

143. In response to information requests, FEI confirmed that, based on its engagement with Indigenous communities, FEI has not been informed of any issues of law or jurisdiction that could impact the Project or its timing,[186] and is not aware of any material objection to the Project.[187]

144. An updated Table 8-4 summarizing FEI's consultation with Indigenous communities to date was provided as follows:[188]

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184 Exhibit B-1, pp. 122-123.

185 Exhibit B-1, p. 129.

186 Exhibit B-4, BCOAOP IR 1.3.1.

187 Exhibit B-4, BCOAOP IR 1.3.2.

188 Exhibit B-2, BCUC IR 1.33.1

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Splats'in First Nation	In person meeting May 2, 2018 with Director, Title & Rights to discuss Inland Gas Upgrades Project and lateral locations within Splats'in area of interest. Director confirmed they would like to be kept informed about work on SAL LTL and SAL LOP as there is potential for impact to known traditional land use areas and unrecorded archaeological areas; also discussed potential for procurement through Splats'in development corporation business Yucwmenlúcwu, a cultural and natural resource management company.	FEI will continue to provide updates as the Project moves forward, construction timelines are confirmed and procurement opportunities are identified. FEI will continue to meet with the Splats'in First Nation as needed.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	Follow up meeting held on July 17, 2018 with Yucwmenlúcwu of Splats'in Indian Band. Discussed Project scope, areas of interest to the community and procurement/training opportunities.	FEI will continue to meet with Yucwmenlucwu to provide updates on construction timelines and procurement opportunities.	
Westbank First Nation	FEI had an in-person meeting on May 31, 2018 with Westbank First Nation Intergovernmental Affairs, Rights & Title and Referrals Coordinator regarding KEL 1 LOP. FEI advised that proposed work is for pressure regulating stations and additional land around the existing station will be required.	FEI to follow up with Westbank First Nation Archaeology to discuss any concerns regarding land requirements.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Stk'emlupsemc te Secwepemc Nation (SSN)	FEI received an email request on May 10, 2018 from Referral Manager for additional maps. FEI requested an in-person meeting to share more information. The meeting was rescheduled twice by Referrals Manager.	FEI spoke with the Director of Operations (Otis Jasper) in an informal meeting about the Project and he did not seem concerned due to the construction being 3 years out. Detailed meeting on the Project will be called in the future and maps will be shared at that time.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Bonaparte Indian Band	On June 4, 2018, FEI received an email response to notification letter from the Director of Natural Resources, requesting clarification regarding the area of the proposed pipeline.	FEI responded that the proposed work is in the area of Kamloops, outside the area of interest for Bonaparte Indian Band.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Southern Dakelh Nation Alliance	On May 8, 2018, FEI received an email response to the notification letter from the Land and Resource Officer directing FEI to engage with alliance member bands directly.		**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Lheidli T'enneh	On May 9, 2018, FEI received a response to the notification letter regarding the consultation process the band prefers.	FEI followed up with Referrals Officer to determine what other information is required and sent the requested information to the Referrals Officer. FEI is committed to meeting with the Lheidli T'enneh again once more information on the Project is available to share.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	On November 22, 2018, FEI met with Chief Dominique and Band Manager Joe.	FEI provided them with an update on the Project, no concerns raised and no additional follow up is required at this time.	

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Ktunaxa Nation Council	FEI had an in-person meeting at the Ktunaxa Nation Council Office on June 8, 2018. Five representatives of the Lands Sector of the Ktunaxa Nation attended. A follow up meeting was held at the Ktunaxa Nation Council Office on June 28th with the Economic Sector of the Ktunaxa Nation. Attendees discussed ways in which the Ktunaxa Nation and community-owned businesses could participate in the Project. FEI assured the Ktunaxa Nation that there would be ongoing engagement on economic opportunities.	The Ktunaxa Nation has provided FEI a letter (Appendix R-3) outlining details they would like to see included in the Environmental and Archaeological plan for the Project. The letter also outlines their position on how to engage, and provide economic and employment opportunities during the length of the Project.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	FEI had an in-person meeting at the Ktunaxa Nation Council Office on August 29, 2018. Two representatives of the Economic Development attended. FEI provided them with an update on the Project.	FEI will continue to keep the Ktunaxa Nation Council informed as the Project progresses.	
Neskonlith Indian Band	FEI had an in-person meeting with the Tmicw Department on June 19, 2018 to discuss the Project. The Neskonlith Indian Band Chief joined the discussion by phone. Tmicw requested more detailed information regarding each lateral, and expressed interest in procurement opportunities during the archaeological work and construction.	FEI sent shape files for each lateral location and additional detailed Project information on June 26, 2018.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	Follow up meeting with Executive Director was held on July 23, 2018. The discussion focused on potential procurement and training opportunities	FEI will have ongoing meetings as the Project progresses to keep community up to date on developments.	

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Osoyoos Indian Band	FEI had an in-person meeting on July 4, 2018 with Referrals Coordinator to discuss the Project. Request to see the environmental plan once complete and review dig locations for culturally sensitive areas, not just archeological sites	FEI provided digital shape files for the laterals in Osoyoos Indian Band traditional territory, and copy of the archeological and environmental assessments currently underway.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Coldwater, Cook's Ferry and Siska Band	FEI received an email on July 6, 2018 acknowledging receipt of notification letter from FEI.	FEI responded and offered to meet and discuss the Project.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Okanagan Indian Band	FEI received confirmation of receipt of notification letter on May 9, 2018.	FEI responded and offered to set up a meeting to review the Project in more detail.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC

145. In addition, the table provided in response to BCUC IR 33.24 shows Indigenous communities that have responded to FEI's notification letters and those that have not. FEI has taken into consideration any feedback from the First Nations into its project and procurement plans for these laterals, such as modifying the proposed Archeological and Environmental activities for these laterals. FEI expects to do a similar range of engagement, and inclusion of feedback, for the remaining laterals as site-specific details become known.[189]

146. FEI's consultation activities to date are the first part of a multi-stage, multi-year Indigenous engagement plan by lateral that also relies on the BC OGC Indigenous Engagement process. FEI's Indigenous engagement framework can be separated into three phases:[190]

- Phase 1 – pre-application engagement for the BCUC process;

189 Exhibit B-10, BCUC IR 2.60.1.

190 Exhibit B-10, BCUC IR 2.60.1.

- Phase 2 – pre-application engagement for the BC OGC process; and
- Phase 3 – post-application engagement (during construction and beyond permitting).

147. Each phase covers the areas of general engagement, archaeology, and procurement. In order to receive its permit(s) from the BC OGC, FEI is tasked with engaging with First Nations but has not been delegated the duty to consult.

148. FEI's approach with respect to its engagement with Indigenous communities on the Project is consistent with FEI's approach taken on previous projects and has been previously accepted by the BCUC.[191] The BCUC has previously acknowledged in the decision associated with Order C-11-15 the adequacy of this process and the responsibility for reciprocity from First Nations:

> The Panel finds that First Nations engagement efforts to date are acceptable. FEI has identified First Nations who assert rights in the project area, notified them of the projects and has been responsive to those First Nations who engaged with it. The Panel accepts FEI's position that to respect the First Nations administrative capacity, it provided updates to those First Nations who had engaged. The Panel is aware that there is a reciprocal responsibility on First Nations to engage with proponents.
>
> Moreover, FEI has outlined its plans for further engagement in conjunction with the OGC permit application process.
>
> The Panel notes that the OGC is the Crown agency responsible for First Nations consultation and that consultation is ongoing. FEI is only responsible for conducting preliminary discussions with identified First Nations and providing documentation for the OGC review process. The adequacy of First Nations consultation will be addressed by the OGC.

149. FEI considers that its engagement activities with Indigenous communities to date have been sufficient, appropriate and reasonable. FEI has notified each identified Indigenous community about the Project, and FEI has met with and provided information back to these communities as requested. Where requests were made for more detail than is currently available, FEI has committed to ongoing engagement through follow-up meetings to share

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[191] Exhibit B-11, BCUC CONF IR 2.14.1

information as it becomes available. FEI has also provided letters to each Indigenous community advising of the filing of the Application and how to get involved in the process to review the Application. During the BC OGC permitting and consultation process that will occur prior to construction, more detailed Project information will be provided to the Indigenous communities for review and comment.[192]

150. As the Project progresses into later stages, FEI will continue to work with Indigenous communities to keep them apprised of new developments, including all follow up commitments. The identified Indigenous communities will also have a number of additional opportunities to comment on Project-specific impacts including during the BC OGC permitting process. Given the stage of the Project, the information available at this time, and the additional consultation required to occur in the future, FEI's consultation activities to date have been sufficient and reasonable.[193]

PART SEVEN: CONCLUSION

151. FEI's evidence in this proceeding is comprehensive, responding to all issues raised, and conclusively demonstrates that the Project is in the public interest. The need and justification for the Project is clear and FEI's alternatives analysis has been designed to ensure that the most cost-effective feasible alternative has been chosen for each of the 29 Transmission Laterals. FEI's cost estimate is reasonable and robust, appropriately including contingency and management reserve reflecting the attributes and risk of the Project. The Project is expected to have minimal environmental and archeological impacts, and FEI's public consultation and early engagement with Indigenous communities has not indicated any significant concerns.

[192] Exhibit B-2, BCUC IR 1.33.2.1

[193] Exhibit B-1, 129-130.

152. FEI submits that the BCUC should grant a CPCN for the Project and approve FEI's proposed deferral account to capture the costs of preparing the Application and evaluating the feasibility of and preliminary stage development of the Project.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Dated: September 27, 2019

[original signed by Chris Bystrom]
Chris Bystrom
Counsel for FortisBC Energy Inc.