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October 11, 2019

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

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

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's Final Submissions with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: Registered Interveners
cc: BCH
cc: CEC

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

FINAL SUBMISSIONS

Re: FortisBC Energy Inc.

Application for a Certificate of Public Convenience

and Necessity for the Inland Gas Upgrade Project

INDEX

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

FINAL SUBMISSIONS

FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project

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1. The Commercial Energy Consumers Association of BC (CEC) represents the interests of ratepayers consuming energy under commercial tariffs in applications before the BC Utilities Commission (BCUC or Commission).

2. In December 2018, FortisBC Energy Inc. (FEI or the Company) filed an application for a Certificate of Public Convenience and Necessity (CPCN) for its "Inland Gas Upgrades Project" (the "Project" or the "IGU Project") (the "Application") pursuant to sections 45 and 46 of the Utilities Commission Act (UCA), and for a deferral account pursuant to section 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.[1]

3. The CEC provides the following Submissions and Recommendations for the Commission's review and consideration.

Summary Position and Recommendations

4. The CEC is of the view that FEI's proposal to upgrade the 29 transmission laterals to necessary safety standards is in the public interest, and recommends approval by the Commission.

5. The CEC submits that it may be appropriate for the Commission to condition its approval on having FEI conduct additional work quantifying risk and prioritization activities and providing reporting to the BCUC such that the Commission can ensure that the Project is undertaken in the most cost-effective manner possible.

6. The CEC notes the substantial capital requirements (over $300 million) to upgrade the transmission laterals, which will be included in rate base and result in increases in rates of 4.3%.[2]

7. The CEC acknowledges that FEI has provided significant qualitative evidence as to the need for remedial measures with regard to the issue of corrosion and potential for rupture,

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[1] FEI Final Argument page 1
[2] Exhibit B-1-2 Update to page 2 of the Application

but submits that the urgency for all aspects of the Project has not been as well-established in the evidence as might be appropriate in the context of over $300 million in capital expenditures.

8. FEI has not prioritized the 29 transmission laterals relative to each other, nor has it prioritized the IGU Project relative to other pipeline improvements within the sustainment capital program.[3]

9. The CEC submits that it could potentially be beneficial for the utility to examine the value of a staged option, under which FEI would conduct further quantitative analysis on an ongoing basis to:

   - Assess the condition of the laterals and establish priorities with a quantitative evidentiary base;
   - Examine the potential for deferral of upgrades to certain laterals either to promote cost savings based on timing or enable alternative technologies to advance to commercial viability;
   - Further examine whether or not PRS could be reasonably provided at greater cost-effectiveness in some instances.

10. The CEC would not support a project deferral that could unreasonably increase the risk of significant negative consequences which jeopardize the safety or well-being of any community or individual, create irreversible harm to the environment, or result in customer service disruptions or widespread outages.[4]

11. However, FEI has provided evidence that the pipelines can currently be considered safe[5], and the Company employs an Integrity Management Program for Pipelines using available methods to mitigate the risk.[6]

12. The CEC has not identified any substantive evidence in this proceeding as to when one or more of the 29 transmission laterals may become unsafe.

13. The CEC accepts that the IGU Project, or some version thereof, is necessary to maintain compliance with legal and regulatory obligations.[7]

14. The CEC would also not support a deferral which resulted in FEI failing to meet regulatory standards and best practices in a timely manner.

15. However, CEC also did not find evidence establishing a particular timeframe urgency on the part of regulatory requirements that could not be still be met but allow for some delays

[3] Exhibit B-5, CEC 1.11.2
[4] Transcript page 9
[5] Exhibit B-5, CEC 1.18.1 and 1.18.2
[6] Exhibit B-5, CEC 1.18.1
[7] Exhibit B-5, CEC 1.18.2

to permit additional analysis to be undertaken or possible prioritization of high-risk laterals.

16. The CEC submits that continued work on a Quantitative Risk Analysis with ongoing evaluation of the options and ongoing reconsideration of how deferrals might allow for some improvements in cost-effectiveness could be an appropriate method for proceeding.

17. The CEC notes the sizeable nature of the contingency allowance based on uncertainties, and submits that it would be worthwhile to minimize the uncertainties to the greatest extent possible before committing to certain courses of action.

18. The CEC recommends that the Commission accept the proposed deferral account as proposed by FEI.

Project Application and Commission Evaluation

19. FEI's IGU Project proposes to upgrade 29 of FEI's transmission laterals located in the interior operating region. FEI provides a list of the transmission laterals in Appendix B of the application.

20. The 29 transmission laterals do not have In-Line Inspection capability due to their size[8], and are operating at hoop stress of 30 percent or more of the Specified Maximum Yield Strength (SMYS) of the pipe. Consequently, the laterals have the potential to fail by "rupture", as opposed to by "leak" only.[9]

21. FEI describes the IGU Project as a "pipeline-integrity project" which is concerned in particular with improving how FEI manages external corrosion, which is the leading cause of pipeline failures.[10]

22. The 29 transmission laterals within the scope of the Project (the "29 Transmission Laterals") are the only remaining pipelines on FEI's system 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.[11]

23. For each of the 29 Transmission Laterals, FEI will either:

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[8] Exhibit B-1, page 21
[9] Exhibit B-1, page 19-24
[10] FEI Final Argument page 1
[11] Exhibit B-5, CEC 1.1.1 The single remaining transmission lateral is the Tilbury LNG Plant 168 mm lateral.

- 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).

24. The Project is estimated to have a capital cost of approximately $320 million[12] (AACE Class 3 estimate), and was included in FEI's most recently filed Long Term Resource Plan.[13]

25. FEI has planned to proceed with the IGU Project as quickly as reasonably possible to address the risk of rupture due to undetectable external corrosion.[14]

Certificate of Public Convenience and Necessity

26. FEI applies for approval of its Project pursuant to sections 45 and 46 of the UCA.[15]

27. The 2015 CPCN Guidelines were established by Commission Order G-20-15.

28. The Guidelines require that the Application address:

- The Applicant
- Project Need, Alternatives and Justification
- Consultation
- Project Description
- Project Cost Estimate
- Provincial Government Energy Objectives and Policy Considerations
- New Service Areas

29. The CEC has reviewed the Application with regard to compliance with the CPCN Guidelines and submits that FEI has adequately addressed the key requirements of a CPCN application.

Commission Evaluation

30. The CEC submits that the IGU Project, as submitted, represents a substantial addition to rate base and ratepayer costs, and as such, requires careful consideration by the Commission in weighing the risks and costs to ratepayers against the potential benefits, and evaluating the quality of the Application.

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[12] FEI Final Argument page 39
[13] Exhibit B-1, page 131
[14] Exhibit B-12, BCOAPO 1.1
[15] Exhibit B-1, page 1

31. FEI's Application is justified on the basis of qualitative analysis and does not have a quantitative risk assessment to provide additional comfort as to the Project need, and urgency.

32. The CEC submits that it would have been preferable for the Commission to have had more quantifiable information available to it.

33. The CEC submits that in the determination of the public interest it would be reasonable for the Commission to give significant weight to the interests of safety and the evidence related to risks of rupture associated with the known issue of cathodic protection shielding and corrosion.

34. The CEC recommends that the Commission also give significant weight to the judgement of FEI engineers as to the need for risk mitigation, and the evidence provided by the Oil and Gas Commission supporting the Project.

35. The CEC recommends that the Commission also consider the absence of quantitative risk assessment ("QRA") and whether or not such information could establish an opportunity to limit, or offer cost savings in the construction of the Project.

36. The CEC submits that the evidence presented by FEI with respect to not first developing its QRA and identifying Project priorities is not compelling.

Project Need and Justification

37. FEI's Project need and justification are premised on the risk of external corrosion and the potential for failure by rupture.

38. FEI conducts a comprehensive Integrity Management Program (IMP) as required by BC Oil and Gas Commission. FEI relies on two primary methods to assess and monitor the condition of its pipelines, which includes In-Line Inspection and Modified External Corrosion Direct Assessment (Modified ECDA).[16]

39. The transmission laterals in question do not have the capability for In-Line Inspection and are inspected with the Modified ECDA.

40. FEI currently relies on coatings and cathodic protection (CP) and above-ground detection methods to identify occurrences of corrosion.

41. FEI has provided evidence of CP shielding on its pipeline system[17], and the Modified ECDA methodology does not detect sites that could be experiencing active corrosion in the areas where CP shielding is occurring.[18]

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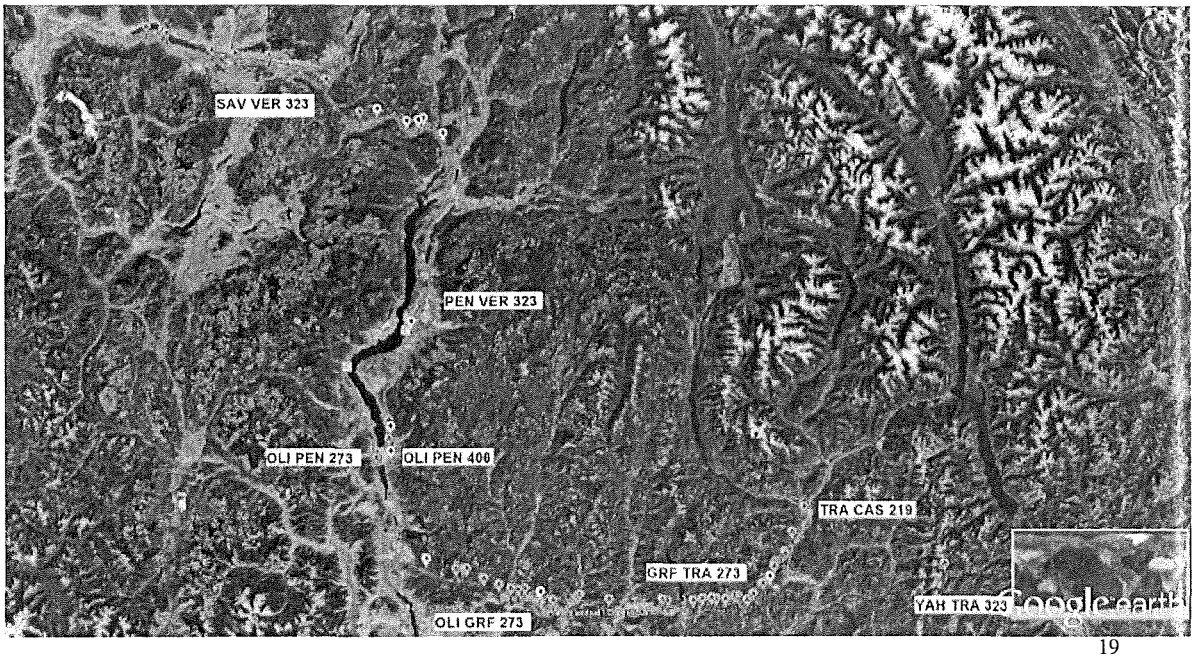
[16] Exhibit B-1, page 5
[17] Exhibit B-5, response to CEC IR 5.2
[18] Exhibit B-1, page 5

42. FEI has also provided evidence of both active and passive corrosion.

43. Figure 2 demonstrates 64 active and 12 passive corrosion sites in the Interior of BC.

Figure 2: Interior Dig Locations (64 active and 12 passive corrosion sites)



[19]

44. FEI does not have a reliable way to detect where corrosion is occurring.[20]

45. 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.[21]

External Corrosion

46. In its Final Argument FEI states that external corrosion is the leading cause of pipeline failures.[22]

47. The CEC does not find evidence to support the statement that "external" corrosion alone is the leading cause of pipeline failure[23], but nevertheless accepts that external corrosion

[19] Exhibit B-5, CEC 1.10.1
[20] Transcript page 13, https://www.bcuc.com/Documents/Transcripts/2019/DOC_54590_2019-07-10-Transcript-V1-Workshop.pdf
[21] FEI Final Argument page 5
[22] FEI Final Argument page 1
[23] The CEC notes that the CAPP report ranks "internal corrosion" rather than external corrosion as the "top failure type", although "metal loss" undifferentiated between internal and external corrosion is a leading cause of pipeline incidents and external metal loss is a leading sub-cause for ruptures. Exhibit B-5, CEC 1.8 and 1.9 series

is one of the most significant causes of failure[24] and that "metal loss due to corrosion" in general (internal and external) is the leading cause of pipeline failure.[25][26]

48. Causes of pipeline incidents in Canada, 2013 – 2017 are shown in the table below.

Product = Gas	
Rupture Sub-cause *	Total
Company Contractor	1
Defective Pipe Body	2
External Metal Loss	5
Fatigue	1
Hydrogen Induced Cracking	1
Stress Corrosion Cracking	6
Grand Total	16

[27]

49. FEI has recorded only one failure on the 29 Transmission Laterals caused by external corrosion, a leak detected by a routine leak survey on the Fording Lateral 219 in 1996.[28]

50. Overall, the CEC is satisfied that corrosion may represent a significant risk to FEI's 29 Transmission Laterals in question and should be addressed in a timely manner.

Risk Assessment

Qualitative Risk Assessment

51. FEI provides a QRA to provide the justification for the Project.

52. FEI states that:

> "Given FEI's demonstration of a risk of failure, and given that a rupture of its NPS 6 and greater transmission pipelines due to external corrosion represents unacceptable performance under FEI's IMP-P, FEI's qualitative risk assessment is that the IGU Project is necessary and should be completed within a 5 year time horizon as proposed in the application."[29]

53. The potential consequences associated with a pipeline failure are significant.[30]

54. In the case of the IGU Project, FEI's qualitative risk assessment utilized an "acceptable / unacceptable" criteria rather than a "high, medium, low" ranking and was performed on

[24] Exhibit B-5, CEC 1.8 and 1.9 series
[25] Exhibit B-1, p. 18; Evidence of Bryan Balmer, Transcript, p. 50, lines 2-3.
[26] Exhibit B-1, Appendix C.
[27] Exhibit B-5, CEC 1.9.3
[28] Exhibit B-10, response to BCUC IR 39.3
[29] Exhibit B-10, BCUC 2.35.11
[30] Exhibit B-5, CEC 1.3.2

all 29 Transmission Laterals instead of on a lateral-by-lateral basis. The assessment found that:

- external corrosion is a relevant hazard (and the leading cause of transmission pipeline failures in British Columbia);
- there is a potential for transmission pipeline rupture due to external corrosion;
- rupture could result in significant consequences; and
- FEI's status quo method to mitigate the potential for external corrosion-related rupture of the 29 Transmission Laterals is now considered by FEI to be unacceptable over the long term.

55. Given the nature of the risk, and the potential consequences of a rupture, no further classification (e.g., high, medium, low) is necessary.[31]

Quantitative Risk Assessment

56. FEI confirms that it has shown no systematic quantitative process to determine risk and no quantitative process to analyse the hazards, their potential interactions and overall impact on risk.[32]

57. FEI has not conducted an explicit estimation of the likelihood of failure resulting from pipeline hazards including external corrosion, third-party damage, geotechnical, seismic and human error for the 29 Transmission Laterals, nor the potential location-specific consequences (safety and security of supply) for each potential failure type (leak and rupture).[33]

58. The BC Oil and Gas Commission (BC OGC) has provided direction to FEI to develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets,[34]

59. FEI has determined that the best response to the OCG direction is to develop a QRA[35] that can be applied to FEI's BC OGC regulated pipeline assets in BC.[36]

60. FEI proposes to conduct a QRA after the implementation of the IGU program.[37]

61. FEI has not yet scheduled an appointment with the BC OGC to review the first iteration of the QRA.[38]

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[31] Exhibit B-18, BCUC IR 64.1
[32] Exhibit B-10, BCUC 2.35.2
[33] Exhibit B-10, BCUC 2.35.7
[34] Exhibit B-20, CEC 3.45.4
[35] Exhibit B-2, CEC 1.3.1
[36] Exhibit B-17, page 1
[37]
[38] Exhibit B-20, CEC 3.45.3

62. FEI states that a QRA was not considered necessary by FEI to justify or inform the IGU Project. FEI has proposed the IGU Project on the basis of the identified potential for failure by rupture due to corrosion on the 29 Transmission Laterals. FEI has also considered inputs such as its legal and regulatory obligations, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as FEI's knowledge of evolving technology available for assessing and managing pipeline condition.[39]

63. In its Final Argument FEI is explicit in its views that:

> "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."

64. FEI provides evidence from JANA that a QRA would not change the need for the Project.[40]

> "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." [41]

65. FEI devotes more than three pages of its Final Argument as to why a QRA is not required to justify the Project.

66. In particular, Mr. Chernikhowsky is quoted at length.[42]

67. In the Transcript, Mr. Chernikhowsky explains that a QRA is used to prioritize complex work or to identify otherwise unknown risks called "interacting threats"; and he points out that projects to address specific known hazards or required to maintain compliance with regulations and industry practice continue to be prioritized first.[43]

68. Additionally, Mr. Chernikhowsky points out that a utility relies upon its professional judgement for many factors.[44]

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[39] Exhibit B-5, response to CEC IR 3.4
[40] FEI Final Argument page 19
[41] FEI Final Argument page 19
[42] Transcript page 14
[43] Transcript page 15
[44] Transcript page 15

69. The CEC accepts the importance of relying on professional judgement for utility safety and reliability, as well as other factors.

70. Similarly, the CEC accepts that projects to address known hazards and maintain compliance with regulations and industry practice are also significant priorities.

71. Nevertheless, the CEC does not find the documentation of risk and urgency of the Project to be compelling.

72. FEI did not engage a risk assessment professional to assess the extent of the risk,[45] and did not complete a detailed analysis of the economic consequences of a pipeline rupture causing a gas supply loss for the IGU laterals.[46]

73. The CEC notes that for the Huntingdon Station Bypass CPCN the utility engaged Dynamic Risk Assessment Systems to complete a QRA which was available in the CPCN though the capital cost was in the order of only $7.6 million, and the potential impacts included multiple hospitals, emergency facilities, care homes, schools and public assembly facilities.[47]

74. The CEC notes that the capital cost of the IGU Project is over $300 million and some of the transmission lines are in rural and relatively unpopulated areas.[48]

75. The CEC accepts and supports FEI's need to comply with regulation and industry standards, and most importantly agrees with the requirement to ensure the safe delivery of natural gas.

76. The CEC notes the OGC's support of FEI taking action to address its known integrity concerns.[49]

77. The CEC also accepts that a QRA would likely not have made any change to the overall need for a Project to mitigate the risks of rupture and to be compliant with regulations and industry best practices.

78. Nevertheless, the CEC is of the view that a QRA prior to the implementation of the Project could have been worthwhile and potentially offered quantitative support for a decision to proceed in a different manner.

79. The CEC submits that it could have been prudent for the utility have conducted the QRA prior to the commencement of the Project, as the availability of the QRA could have provided additional comfort to the Commission for Project justification given the

[45] Exhibit B-5, CEC 1.3.7
[46] Exhibit B-5, CEC 1.11.1
[47] Exhibit B-5, CEC 1.3.8
[48] Workshop Transcript page 12
[49] FEI Final Argument page 22

significant magnitude of the Project, as well as safety priorities in approving the application.

Risk Prioritization

80. The 29 subject Transmission Laterals range in age from approximately 24 years to 62 years since construction.[50]

81. FEI's assessment is that there is no material difference in the overall integrity risk level of the laterals as they are subject to the same potential for rupture due to external corrosion that may go undetected by FEI's current integrity management techniques. FEI's integrity assessments do not provide information to suggest there would be material improvement from a safety or reliability perspective by prioritizing the laterals differently from currently planned. [51]

82. FEI states that it has limited ability to prioritize amongst the laterals based on risk levels because the condition information on these laterals does not provide any indication of localized issues on any particular lateral.[52]

83. FEI also states that "Even if a more granular assessment of risk could be undertaken, a reprioritization of the work for the IGU Project would not have a material benefit…..Prioritizing the work on one or more of the 29 Transmission Laterals compared to FEI's planned implementation of the IGU Project would not materially reduce the risk".

84. FEI states that in the absence of an in-line inspection program it is not feasible to pinpoint areas in FEI's pipelines that may be experiencing cathodic protection (CP) shielding.[53]

85. In BCUC 1.35.2, FEI confirms that the risk associated with FEI's pipelines can vary according to location, material, pressure, current, age and condition.[54]

86. On July 10, 2019, Mr. Chernickhowsky provided evidence related to the identifying potential impact radii that could occur from a pipeline rupture, and used an example in the Kelowna Loop 1 that would encompass much of one of the buildings in a condominium complex.

87. The CEC submits that such information is valuable in understanding risk and prioritizing mitigation.

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[50] Exhibit B-2, BCUC 1.1.1 and 1.3.1
[51] Exhibit B-20, CEC 3.46.2
[52] Exhibit B-20, CEC 3.46.2
[53] Exhibit B-13, CEC 2.38.1
[54] Exhibit B-10, BCUC 2.35.2

88. However, in response to CEC 3.46.1 FEI states that it has not conducted any explicit assessments of the highest potential impacts from ruptures at this time.[55]

89. The CEC submits that the dearth of such information diminishes the Commission and interveners' ability to fully understand the risks FEI proposes to mitigate with over $300 million in spending.

Project Costs

Project Costing

90. The estimated total cost for the IGU Project will be $360.193 million in as-spent dollars including AFUDC, contingency and management reserve.[56]

91. The IGU Project has a total delivery rate impact over six years of 4.30% and a levelized delivery rate impact of 3.05% over 66 years.[57]

92. The average rate impact over the first 5 years is approximately 0.71% per year, or $0.029 per GJ from 2020 to 2025. For residential customers this equates to an annual increase of approximately $2.63/year.[58]

93. The CEC submits that these do represent a significant rate impact and should be provided with significant consideration by the Commission.

94. The Project is developed to a Class 3 cost estimate for each lateral, in accordance with AACE specifications and as required by CPCN Guidelines.[59]

95. FEI responded to multiple information requests including confidential information requests with regard to the costing of the Project.[60]

96. The CEC has reviewed the evidence related to the cost estimate and is largely satisfied with the costing, subject to comments below.

97. The CEC notes that the cost estimates provided in the Application are for the proposed Project in its entirety. The CEC submits that the Project as proposed is a large capital expenditure with a substantial contingency and management allowance due to uncertainty. The CEC further submits that the impact to ratepayers might be mitigated through data gathering and QRA to reduce uncertainty and potentially reduce cost impacts to ratepayers.

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[55] Exhibit B-20, CEC 3.46.1
[56] FEI Final Argument, page 39 NB $361.184 million Exhibit B-1-2
[57] Exhibit B-1, page 85 with modification in Exhibit B-1-2
[58] Exhibit B-1 page 87
[59] Exhibit B-1, page 64
[60] Exhibit B-18 BCUC 3.71.1, B-18 BCUC 3.73.1.1, B-5 CEC 1.2.3.1, B-5 CEC 1.24

Capital Spending Management

98. The CEC notes that in the Project capital budget, over 70% of the total cost is attributed to the 11 laterals in which the selected method is In-Line Inspection (ILI).[61]

99. The CEC notes that a breakdown of the Project costs indicates that these ILI projects will be conducted over 5 years and that approximately $51 million is planned to be spent on ILI project(s) the first year, and $76 million the second year,[62] representing over $127 million in spending.

100. The CEC submits that the ILI project(s) undertaken in the first year could potentially provide an opportunity to reassess the risks, timing and the overall IGU Project.

101. The CEC is of the view that the ILI projects mentioned above could potentially provide valuable data as to the condition of the lateral pipes. Information gathered as to the condition of the laterals examined in year 1 may possibly be extrapolated to provide the basis for a quantitative risk assessment of the remainder of the 29 laterals.

102. The CEC considers that this might be a prudent way to invest in risk mitigation, without compromising safety.

103. The CEC notes that Pipeline Replacement (PLR) project(s) in the second year total approximately 11 million dollars.[63] These projects would also provide an opportunity to evaluate not only the pipeline integrity, but also the coating and exterior condition of the pipe.

104. The CEC notes that pipeline inspection technologies, such as Robotic Inspection or others, continue to develop and could potentially become proven and commercialized over the next few years. Such technologies could potentially present cost-effective alternatives in the future.[64]

105. The CEC recommends that the Project be approved, but submits that it could be reasonable for the Commission to condition its approval on ongoing analysis and reporting, with the expectation that information from the first one or two years of the Project be used to evaluate the need for the rest of the Project to proceed as proposed.

106. The CEC submits that approving the IGU Project with such conditions could potentially protect ratepayers from expenditures that may be deferred or redeployed, and might

[61] Exhibit B-1, Table 6-2, page 84
[62] Exhibit B-1, Table 6-4, page 86
[63] Exhibit B-1, Table 6-4, page 86
[64] Exhibit B-5, CEC 21.1

effectively provide a service to the public that is adequate, safe, efficient, just and reasonable.[65]

Contingency

107. FEI states that the Project cost estimate includes contingency of 17 percent as well as a management reserve of 11 percent.[66]

108. FEI stated it has not previously included a management reserve in addition to contingency.[67]

109. The CEC notes that the contingency and management allowance of 28% represents approximately $100 million.

110. The CEC submits that this contingency is very large and should be carefully managed to ensure it is minimized to the extent possible.

111. FEI states that the low-quality, less-granular data available for the 29 laterals results in assumptions being made during the risk estimation, which is reflected in larger uncertainty or error bounds around the estimated failure rates.[68]

112. The CEC submits that improving the quality of data available as to the condition of some laterals may be representative of the condition of the remainder of the 29 laterals. This information could reduce risk and reduce the amount required for contingency.

113. The CEC submits that the contingency amount represents a potential source of cost savings and which might benefit from greater information. This could be gleaned from staging the Project using information from the first year or two to inform the work on the remaining laterals.

114. FEI considered that its use of the word "cost-effectiveness" for this Project is "the best overall outcome of expected impacts and risks for ratepayers over the long run."[69]

115. The CEC submits that the IGU Project as submitted could potentially result in higher costs than may be necessary if better information were available.

116. FEI states that a segment-by-segment risk analysis or QRA is not needed for the Project, as compliance with codes and regulations are the only drivers necessary to support the need for the IGU Project.[70]

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[65] Utilities Commission Act, clause 38
[66] FEI Final Argument, page 39, paragraph 110
[67] Exhibit B-2, response to BCUC IR 23.1
[68] FEI Final Argument, page 20, clause 55
[69] Exhibit B-5, response to CEC IR 2.2
[70] FEI Final Argument, page 22, clause 57

117. FEI states it does not have condition assessment or other information that would support the need to expedite or delay the Project timeline, and notes that information available on the 29 Transmission Laterals indicates there is not a material difference in the integrity risk level of the laterals or systemic issues.[71]

118. The CEC reiterates its view that a QRA would have been desirable for a project having such a sizable impact on ratepayers.

119. The CEC submits that it could be in the best interest of the public for FEI to gather more information on the 29 laterals before proceeding on a comprehensive project as described in this proceeding.

120. The CEC further submits that acquiring detailed information on a few laterals may provide representative data that can increase certainty, reduce the amount required for contingency and management reserve, lowering overall Project costs and protect ratepayers from rate impacts that may be unnecessary.

Alternatives Analysis

121. FEI states that they analysed 7 alternative integrity management alternatives to mitigate the potential for rupture failure due to corrosion on the 29 Transmission Laterals. [72]

122. These included:

- Modified External Corrosion Direct Assessment (modified ECDA) (status quo)
- Pipeline Exposure and recoat (PLE)
- Hydrostatic testing program (HSTP)
- Pressure Regulating Stations (PRS)
- In-line Inspection (ILI)
- Pipeline replacement (PLR)
- Robotic Inspection (ROB) [73]

123. The CEC submits that FEI's Alternative Assessment was potentially lacking in that it focused only on the technological response to the issue rather than potentially examining all options available, such as deferrals or a staged approach.

124. Consequently, the evidence available for review is premised on the determination that the Project must be addressed in full at this time.

[71] FEI Final Argument, page 44, paragraph 119
[72] Exhibit B-1, page 27
[73] Exhibit B-1, page 27

125. The CEC submits that it could have been appropriate for FEI to have considered, and provided more and quantifiable evidence regarding options such as project deferral, partial deferrals or a staged approach.

Project Deferral or Partial Deferral

126. FEI is explicit in their view that Project deferral is not an adequate option for consideration.

127. The CEC inquired if the Project could be safely deferred for a period of 2 or 5 years or longer in CEC 2.40.1, which was denied by FEI.

128. FEI noted that:

    a. The 29 Transmission Laterals are subject to failure by rupture (refer to section 3.3.3 of the Application);

    b. Pipeline ruptures can result in significant consequences, including serious injuries or worse to employees or the public (CEC IR 1.3.2);

    c. Most transmission pipeline failures are due to external corrosion (section 3.3.1 of the Application and CEC IR 1.9.3);

    d. CP shielding is a known industry issue which can interfere with CP in preventing corrosion, and can also prevent detection of external corrosion (section 3.3.2 of the Application and CEC IR 1.6.3);

    e. Undetectable external corrosion (due to CP shielding) has previously been observed on 22 FEI pipelines and FEI considers it probable that it is occurring throughout the 29 Transmission Laterals (BCUC IR 1.4.1 and CEC 1.10.2); and

    f. Corrosion is a time-dependent hazard; consequently, unreasonably delaying the ability to detect this hazard on the 29 Transmission Laterals will increase the likelihood of a pipeline rupture (BCUC IR 1.3.1).[74]

129. In its Final Argument, under the heading "The Project Cannot Be Safely Deferred", FEI states:

> "…the Project must be carried out 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

[74] Exhibit B-13, CEC 2.40.1

ability to detect (potential failure by rupture) will increase the likelihood of a pipeline rupture."

130. 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 obligations and consistency with industry standard practice, FEI submits that there is no safe period of time over which the Project could be deferred[75].

131. The CEC submits that FEI has clearly made a case justifying the requirement for a project overall, but has not provided significant and quantified evidence to support the urgency of the Project overall, nor it has made a compelling case for not prioritizing the upgrades to laterals based on the riskiest sites.

132. FEI has provided evidence that its pipelines can currently be considered safe[76], and the Company employs an Integrity Management Program for Pipelines using available methods to mitigate the risk[77].

133. The CEC notes that leaks have not been identified since 1966.[78]

134. FEI states that

> "Although (they) have not noted changes to its field operations that would have impacted the occurrence or detection of corrosion leaks on the 29 Transmission Laterals, the absence of leaks could be partially attributable to FEI's development and implementation of an Integrity Management Program through the 2000s. These management systems, which incorporate a plan-do-check-act cycle intended to promote continual improvement, have been adopted by many industries with goals of improving asset performance and reducing failures.
>
> To manage external corrosion on its non-piggable transmission pipelines, FEI was (i.e. in 1996 and before) applying cathodic protection (CP) and periodically monitoring CP systems to ensure their proper function. FEI continues this practice. FEI has also continued to monitor for leaks on its transmission pipelines over this period."[79]

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[75] FEI Final Argument page 22
[76] Exhibit B-5, CEC 1.18.1 and 1.18.2
[77] Exhibit B-5, CEC 1.18.1
[78] Exhibit B-5, CEC 1.30.2 and Exhibit B-13, CEC 2.42.1
[79] Exhibit B-13, CEC 2.42.1

135. The CEC is of the view that this evidence would provide some support for a conclusion that there may not be significant urgency for every aspect of the Project.

136. Overall, the CEC has not identified any substantive evidence in this proceeding as to when one or more of the 29 Transmission Laterals may become unsafe.

137. The CEC submits that the current safety of the pipelines could suggest the opportunity for pursuing the project on a staged basis, allowing for improved information to further inform the decision-making around the urgency of the need and best forms of mitigation.

138. In CEC 3.45.5 the CEC requested quantification of the likely increases in risks that could accrue if the Commission decision were to be deferred.

139. FEI provided a generic answer as to exposure for regulatory, safety, reliability and environmental consequences in the event of a pipeline rupture due to external corrosion.[80]

140. The CEC notes that there could potentially be savings for a 5-year Project deferral assuming no additional capital expenditures or other incremental costs in the near-term because of deferral of the project and assuming the discount rate in the NPV analysis is greater than the rate of Project cost inflation.[81]

141. However, FEI has not conducted the financial analysis of potential savings from deferral "as it would be speculative and would not provide any benefit to address the underlying need of the IGU Project."[82]

142. In response to CEC 3.46.2, FEI states that:

> "FEI is unable to identify any cost savings by conducting the Project over a period of time five years longer than is currently planned. The current Project schedule was developed based on regional distributions of the 29 Transmission Laterals, cost efficiency, and other constraints as discussed in the response to BCUC IR 1.3.1. Therefore, if the Project were to be completed over a longer period of time, FEI expects the project capital costs to be higher taking into account lost efficiencies and cost inflation. Since Project capital cost savings are not expected under this scenario, FEI did not develop a cost estimate or conduct a financial analysis to determine the actual change in the present value (PV) of incremental revenue requirements over the 66-year analysis period."[83]

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[80] Exhibit B-20, CEC 3.45.5
[81] Exhibit B-13, CEC 2.40.2
[82] Exhibit B-13, CEC 2.40.2
[83] Exhibit B-20, CEC 3.46.2

143. FEI also stated it is unable to identify any likely cost savings that could accrue if the Project was to be deferred, and may result in higher capital costs when taking into account inflation.[84]

144. The CEC submits that it is difficult for interveners and the Commission to assess the urgency of the Project or the value of conducting even portions of the Project over a longer period of time given the lack of analysis provided as to the actual risk levels from each lateral over time, and the benefits of any deferral that might accrue from prioritizing risky sites over less risky sites.

145. The CEC considers that it could be possible that a staged option including further analysis and review of additional options while proceeding with the initial stages might potentially identify cost savings from the employment of different technologies or prioritization of the work plan and/or to provide prioritization based on risk.

146. The CEC notes that there is significant variation in the instances of corrosion between the three regions; and also apparent differences in the corrosion geographically within the interior region.[85]

147. The CEC is of the view that it might be possible that FEI could refine its assessment of where corrosion is taking place through increased integrity digs and control digs enabling the utility to address the key concerns while addressing the lower risked laterals more slowly.

148. The CEC notes that FEI would expect that random control digs and integrity digs would cost approximately the same.[86]

149. The CEC submits that an understanding of the corrosion patterns could assist in providing comfort as to the appropriateness of treating all laterals as being equally risky.

150. Notwithstanding the comments above, the CEC submits that there is not sufficient evidence in the proceeding to suggest that FEI has unacceptably brought forward a Project that could be safely deferred, or even staged.

151. The CEC therefore does not oppose the Project approval, but would accept the Commission conditioning its approval on the receipt of information going forward as to possible options for safely deferring or prioritizing segments to improve cost-effectiveness.

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[84] Exhibit B-20, CEC 3.45.6
[85] Exhibit B-5, CEC 1.10.1
[86] Exhibit B-13, CEC 2.36.1

FEI's Alternatives

152. As noted above FEI examined several technological options in addressing the issue of corrosion.

- Modified External Corrosion Direct Assessment
- Pipeline Exposure and recoat (PLE)
- Hydrostatic testing program (HSTP)
- Pressure Regulating Stations (PRS)
- In-line Inspection (ILI)
- Pipeline replacement (PLR)
- Robotic Inspection (ROB) [87]

153. FEI provides an overview of its analysis in section 4 of the Application.

154. FEI considered an analysis period of 66 years in its assessment, which includes six years during the Project for project execution, and 60 years post-Project for lifecycle operation.[88]

155. The CEC submits that the analysis period is reasonable.

156. FEI conducted a Net Present Value (NPV) analysis including estimated capital cost and operating costs, as well as future incremental sustainment capital and operating expenditures.

157. The CEC submits that this is an appropriate financial analysis to undertake for the various alternatives.

158. FEI also provided a Scoring and Weighting system which is outlined in the Application.

159. The CEC has reviewed the evidence and does not object to FEI's analysis and weightings.

160. FEI provides the following chart identifying key characteristics of the alternatives.

[87] Exhibit B-1, page 27
[88] Exhibit B-1, page 34

Activity/ Option	ILI	PLR	PRS	PLE	ECDA	HSTP
Ecological Damage	Low impact during construction and ILI digs	Moderate impact during construction	Low impact during construction	Moderate impact during construction	Low impact during assessment and digs	High impact during testing and repairs
Longevity	Significant increase	Significant increase	No increase (refer to BCUC IR 1.13.2)	Significant increase	Limited increase but not acceptable over the long term	Limited increase
Lifecycle Costs	Moderate Cost for Long Laterals (>5km)	Moderate Cost for Short Laterals (<5km)	Low Cost when feasible	High Cost	Low cost	High Cost when feasible
Benefits	High level of Integrity and Asset Management capabilities; Meets Project Objectives	High level of Integrity and Asset Management capabilities; Meets Project Objectives	Low level of Integrity and Asset Management capabilities; Meets Project Objectives	Moderate level of Integrity and Asset Management capabilities; Meets Project Objectives	Low level of Integrity and Asset Management capabilities; Doesn't meet Project Objectives	Low level of Integrity and Asset Management capabilities; Meets Project Objectives
Other Considerations	High level of project certainty and execution	High level of project certainty and execution	High level of project certainty and execution	Moderate level of project certainty and execution	Moderate level of project certainty and execution	Low level of project certainty and execution

[89]

161. FEI's financial evaluation of the alternatives assumes that the physical lives of the laterals are indefinite.[90] FEI notes that there is no indication at this time that any of the transmission laterals are approaching the end of their useful life.[91]

162. The CEC agrees that it is appropriate to assess the alternatives assuming the physical lives of the laterals are indefinite.

163. However, the CEC submits that it could also be appropriate for the utility to assess the useful life of the pipelines in terms of customer benefit.

164. To the extent that certain laterals may be experiencing decreased use, and lower forecast load, it could be appropriate to adapt the analysis accordingly.

[89] Exhibit B-5, CEC 1.22.1
[90] Exhibit B-10, BCUC 2.45
[91] FEI Final Argument page 25

Maintain Status Quo: Modified External Corrosion Direct Assessment

165. ECDA is a process for managing external corrosion, published as standard ANSI/NACE SP0502-2010.

166. An ECDA is completed in four steps – pre-assessment, indirect inspection, direct examination and post-assessment. Pre-assessment collects and considers available information. Indirect inspection implements above-ground surveys over the pipeline. During direct examination, dig sites are selected and the pipeline is exposed sites for detailed inspection. Control digs are also conducted at random sites to verify the validity and applicability of the methodology. In post-assessment, data from all preceding steps is analyzed and determination is made regarding possible further investigation.

167. The Modified ECDA employed by FEI is less prescriptive than the ANSI standard and allows for variation in the number of digs performed based on FEI's assessment of the value of the dig. ECDA and Modified ECDA are not capable of detecting corrosion in areas of CP shielding due to technical limitations of ECDA methods.[92]

168. FEI determined that the Modified ECDA will not detect sites that may be experiencing corrosion where CP shielding is occurring.

169. FEI therefore screened out this alternative as it does not achieve the primary purpose of the application.

170. The CEC is satisfied that the Status Quo option is not appropriate as a long term option given the circumstances outlined by FEI.

Pipeline Exposure and Recoat (PLE)

171. This alternative involves exposing the entire length of a pipeline, performing a detailed inspection of the pipeline surface and assessing any imperfections, conducting required pipeline repairs, and completing a recoat of the entire pipe surface. The full length of the pipeline would then be re-buried and subject to site rehabilitation and future Modified ECDA. Large-scale in ditch recoating of pipelines is a complex undertaking, and is not typically performed by operators due to high costs relative to other available solutions.[93]

172. FEI rejected this alternative because of the high costs of doing this work and the high degree of site disturbance.

[92] Exhibit B-1 page 28
[93] Exhibit B-1 page 30

Hydrostatic Testing Program

173. A hydrostatic testing program to verify the integrity of a transmission pipeline over its lifecycle involves periodic removal from service, and subjecting it to hydrostatic tests.

174. As the pipelines are required to be out of service for a period of at least a week to implement this alternative on a recurring frequency of 5-10 years it is only appropriate for pipelines that are looped or where customers could be temporarily supplied by another energy source.[94]

175. FEI rejected this alternative because of the disruption to customers resulting from the removal of the pipeline from service.

In-Line Inspection (ILI)

176. In-line inspection includes the insertion of a data device (ILI or pig) inside an operating line to obtain a direct measurement of imperfections such as metal loss, dents, and mechanical damage that may adversely affect the pipeline's integrity.

177. The ILI alternative requires retrofitting an existing pipeline to accommodate inspection tools, and launcher and receiver barrels are also required to be installed.[95]

178. ILI is highly regarded by operators as the data enables rehabilitation to be focused on specific locations and can inform long term asset planning. [96]

179. FEI chose ILI as the preferred alternative for 11 laterals as FEI deemed that a reduction in pipeline pressure was not feasible for these laterals because of customer load forecasts.

180. The CEC notes that once the retrofit of a pipeline has been completed, that will permit ILI to be used on an ongoing basis to monitor the condition of the pipeline over time. The CEC supports the use of ILI for this reason, where feasible and cost effective.

Pipeline Replacement (PLR)

181. PLR involves replacing the existing pipeline with a new pipeline constructed to current standards including accommodations for future ILI capability. This option allows for rupture potential to be mitigated by designing the pipe with an operating stress of less than 30 percent SMYS. As PLR would involve disturbing the ground within the ROW to install the new pipe, there could be more disruption to Indigenous communities, landowners and other stakeholders. The original pipeline remains in-service until the

[94] Exhibit B-1, page 30
[95] Exhibit B-1, page 30
[96] Exhibit B-1, page 30-31

installation of the replacement pipeline is completed, resulting in a requirement for land acquisition.[97]

182. FEI chose to replace four laterals as this alternative was deemed to be more cost effective than ILI or PRS, or a reduction of pipeline pressure was not feasible due to forecast customer loads.

183. The PLR alternative provides an opportunity to gather comprehensive data on the condition of the pipeline under various in-situ conditions. The CEC supports the gathering of this data for use in developing QRA that may inform the work on other laterals.

Pressure Regulating Stations (PRS)

184. PRS involves installation of a pressure regulating station to lower the operating stress of a pipeline to below 30% SMYS. Below 30% SMYS, it is generally accepted that pipeline failures due to pressure-dependent hazards (e.g. corrosion) will have the potential to leak rather than rupture, significantly reducing the potential consequences of failure. The PRS alternative also has the smallest ground disturbance footprint of all the alternatives.[98]

185. Pressure Regulating Stations can represent a very cost effective solution to the issue of corrosion as illustrated below.

[97] Exhibit B-1 page 31
[98] Exhibit B-1, page 30

Table 4-9: High Level Cost Comparisons of PLR to Other Alternatives for Longer Laterals (2018$)

Lateral	ILI ($ millions)	PRS ($ millions)	PLR ($ millions)
Mackenzie Lateral 168	27.6	N/A*	71.7
Mackenzie Loop 168	15.4	N/A*	35.6
Prince George 3 Lateral 219	8.2	1.2	20.9
Northwood Pulp Lateral 168	8.5	1.2	23.4
Northwood Pulp Loop 219	8.0	1.2	22.8
Prince George 1 Lateral 168	8.2	N/A*	18.4
Prince George 2 Lateral 219	8.6	3.5	27.1
Williams Lake Loop 1 168	3.8	1.7	13.2
Williams Lake Loop 2 168	5.4	1.7	9.8
Salmon Arm Loop 168	19.7	N/A*	105.4
Coldstream Loop 168	8.3	3.4	14.7
Kelowna 1 Loop 219	8.3	4.0	8.2
Celgar Lateral 168	6.7	3.5	22.6
Castlegar Nelson 168	36.0	5.3	109.6
Trail Lateral 168	12.3	3.6	20.7
Fording Lateral 219/168	64.0	N/A*	186.8
Cranbrook Lateral 168	10.6	N/A*	79.8
Cranbrook Loop 219	9.1	N/A*	79.8
Cranbrook Kimberley Loop 219	4.8	N/A*	15.7
Cranbrook Kimberley Loop 273	5.3	N/A*	27.6
Kimberley Lateral 168	13.2	N/A*	48.3
Skookumchuck Lateral 219	4.7	N/A*	84.3

PRS was not technically feasible for these laterals and as a result, no cost estimate was developed.
[99]

186. For virtually all options where PRS was not screened out, PRS represents a significant savings relative to the other options, ranging between $2.1 million for the Williams Lake Loop and $30.7 million for Castlegar Nelson 168.

187. The CEC submits that including Pressure Regulating Stations in certain instances could potentially have resulted in significant cost reductions.

188. However, laterals determined to have insufficient capacity to meet the forecasted demand when pressure is regulated to below 30% SMYS were deemed to be not suitable for PRS[100] and were given no further consideration.[101]

[99] Exhibit B-1, page 44
[100] Exhibit B-1, page 30
[101] Exhibit B-1, page40

189. The CEC submits that this potential saving is worth very significant consideration and could be worth revisiting

190. Assuming a $5 million saving per lateral screened out would result in a significant saving.

191. The CEC notes that this demand includes customer demand from interruptible customers.

192. Additionally, the CEC notes that FEI may at times be at or near the maximum operating pressure of each lateral, but will most often be operating at pressures below the maximum operating pressure, and in some cases and the minimum contractual pressure.[102]

193. The CEC submits that it could be very cost-effective to reconsider the potential for PRS under certain circumstances.

194. In CEC 2.37.6 the CEC requested information in order to understand how often interruptible customers experienced interruptions and how this would change if PRS were implemented.

195. PRS was screened out due to capacity issues on approximately 12 laterals covering the MacKenzie system, the Prince George 1 System, the Kamloops System, the Salmon Arm System, the Cranbrook Kimberly System and the Fording System.[103]

196. The Salmon Arm System and the Cranbrook Lateral and Loop 2019 in the Cranbrook Kimberley System could not meet the current and forecasted firm demand on the system if PRS was installed.

197. FEI states that customers could consider alternative fuels such as coal, oil, wood/biomass and electricity if they were curtailed too often.[104]

198. FEI conducted the analysis examining the four-month period November to February over 5 years, 2014-2018.

199. The CEC notes that the analysis does not consider the remaining 8 month period between March and October inclusive.

200. The CEC has reviewed the evidence related to customer impacts and submits that there are cases where the customer impacts may not be significant.

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[102] Exhibit B-13, CEC 2.37.2
[103] Exhibit B-13, CEC 2.37.6
[104] Exhibit B-13, CEC 2.41.3

MacKenzie System

201. With a PRS in place there were 35 more days of potential curtailment than without a PRS[105] over a five year period (2014-2018) (November to February), which represents an approximate 6% increase.[106]

202. Additionally, there would also have been greater curtailment within the periods of curtailment for most days. Based on a review of the recorded tap pressure, there were 2 days when interruptible customers would be required to curtail to a greater degree with PRS and an additional 5 days where curtailment could only be required because a PRS was in place.[107]

203. FEI states that this analysis confirms that the PRS alternative for this lateral would result in more curtailment to the 18 interruptible customers that are currently being served by the system.[108]

204. FEI did not consider the PRS alternative as viable in any system where the peak demand of customers currently served by the system could not be met within the forecast period to the same degree as that provided by the lateral system without PRS. As a result, PRS was not considered a viable alternative for the MacKenzie Lateral.[109]

205. The CEC submits that the MacKenzie Lateral costs of $27 million re significant and it could be worthwhile to further consider a PRS option and alternative means of addressing customer curtailment issues.

Prince George System

206. For the Prince George System 1 Lateral interruptible customers have curtailment potential with or without PRS, but would have a greater degree of curtailment required. Based on the five-year period there were 2 days based on recorded flows where customers would be curtailed to a greater degree with PRS and an additional 41 days were curtailment could have been required only because a PRS was in place.

207. FEI states that "This analysis confirms that the PRS alternative for this lateral would result in more curtailment to the interruptible customers that are currently being served by the system. As a result PRS was not considered viable for the Prince George 1 Lateral."[110]

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[105] Exhibit B-13, CEC 2.37.6.2
[106] Increase = 601/566
[107] Exhibit B-13, CEC 2.37.6.2
[108] Exhibit B-13, CEC 2.37.6.2
[109] Exhibit B-13, CEC 2.37.6.2
[110] Exhibit B-13, CEC 2.37.6.2

208. The CEC submits that and it could be worthwhile to consider a PRS option and alternative means of addressing customer curtailment issues.

Kamloops 1 System

209. For the five-year period there would be an approximate 45% increase in the days where curtailment potential.[111] However, based on the five year period, there no days where customers would be curtailed to a greater degree with a PRS in place.[112]

210. FEI states that "Although the current measured industrial flow may not have triggered additional curtailment with PRS in the 5-year period, their historical demand preceding this period would have. As a result, PRS was not considered viable for the Kamloops 1 Lateral as it could interfere with existing customers returning to historic consumption levels."[113]

211. The CEC submits that there is limited evidence of likely curtailment and a PRS alternative could potentially be reasonably reconsidered.

Cranbrook Kimberley

212. A PRS installed at the common tap to the Cranbrook Lateral 168 and Cranbrook Loop 219 does not provide sufficient capacity to serve Firm customers. As a result no additional review of impacts to interruptible capacity was conducted.

213. However, tap locations further downstream do not impact capacity to serve Firm customers. These include Loop 273, Loop219/Lateral 168 and Skookumchuck Tap.

214. For each location there was an increase of 8 days or a 1.3%[114] increase in the number of days of curtailment potential with PRS versus without PRS.[115]

215. For Loop 273 there were 151 days of 601, where the potential could be higher with PRS.[116]

216. For Loop 219/Lateral 168 there were 363 days of 601 where the potential could be higher with PRS.[117]

217. For Skookumchuck Tap there were 5 days of 601 where the potential could be higher with PRS.[118]

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[111] Increase = 601/412
[112] Exhibit B-13, CEC 2.37.6.2
[113] Exhibit B-13, CEC 2.37.6.2
[114] Increase = 601/593
[115] Exhibit B-13, CEC 2.37.6.2
[116] Exhibit B-13, CEC 2.37.6.2
[117] Exhibit B-13, CEC 2.37.6.2
[118] Exhibit B-13, CEC 2.37.6.2

218. Based on a review of the recorded tap pressure there were no days where the interruptible customers would be curtailed to a greater degree with PRS.

219. FEI states that "This is a result of one of the larger customers not operating at their full capacity within the November to February time period (during) recent years".[119]

220. FEI goes on to state that:

> "Although the current measured industrial flow of customers within the winter period may not have triggered curtailment additional curtailment with PRS in the 5-year period, their measure demand in other period of the year would have. As a result PRS was not considered viable for these Laterals as it could interfere with existing customers consumption should their peak demand coincide with the winter period."

221. The CEC agrees that there is likely no benefit to reviewing a PRS option where firm customers cannot be served.

Fording Lateral

222. For the five-year period there would be an approximate 27% increase in the days where curtailment potential.[120] However, based on the five-year period, there 473 days where customers could be curtailed to a greater degree with a PRS in place.[121]

223. Based on a review of the recorded tap pressure there were 465 days where interruptible customers would have experienced greater curtailment. This analysis confirms that the PRS alternative would result in more curtailment.[122]

224. The CEC agrees that a PRS alternative would likely result in significant issues for interruptible customers.

225. However the costs associated with the Fording Lateral are significant and the CEC considers that all efforts to significantly reduce costs should be reviewed.

226. The CEC submits that the evidence is that the potential for customer curtailment due to PRS varies quite considerably by lateral; and that it is possible that the threshold of meeting all forecasted demand of current and future customers[123] including interruptible customers could result in unnecessary costs.

227. The CEC is of the view that it could be reasonable for FEI to conduct further inquiries with the interruptible customers whose curtailment may not be especially significant to

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[119] Exhibit B-13, CEC 2.37.6.2
[120] Increase = 601/4473
[121] Exhibit B-13, CEC 2.37.6.2
[122] Exhibit B-13, CEC 2.37.6.2
[123] Exhibit B-1, page 30

determine the potential for using other methodologies to mitigate the customer interruptions if savings can be made through the implementation of PRS.

Robotic Inspection (ROB)

228. FEI states that it is monitoring the evolution of ILI tools, and there are potentially feasible applications of these tools, such as for the inspection of short pipeline inspections.

229. However, FEI ruled out the use of robotic ILI tools as being not feasible primarily because they are not deemed to be technologically ready.[124] These are outlined in FEI's Final Argument at page 28.

230. The CEC is of the view that the use of robotic ILI tools could potentially offer a cost-effective option for certain laterals in the future.

231. The CEC inquired in CEC 1.21.1.5 if it could be worthwhile for FEI to postpone certain activities in order to employ robotic ILI in the future. FEI does not consider that it would be worthwhile to postpone the start of the IGU project because the technology time frames for commercialization are unknown and uncertain at this time.

232. However, if FEI identifies a commercially feasible and industry accepted alternative to ILI during implementation of the IGU Project, FEI would evaluate the alternative and advise the BCUC of the results of any changes.[125]

233. FEI considered using robotic inspection technology as a pilot (sample) test in parallel with ILI technology to determine its potential efficacy, but found that at this time the technology is not sufficiently proven and commercialized such that FEI cannot ensure with reasonable certainty that there would be financial and informational value in such an undertaking. FEI's future evaluation of robotic inspection technology may involve pilot testing.[126]

234. The CEC submits that FEI's approach to monitoring the status of robotic tools during the implementation of the Project is reasonable to the extent that the Project is approved and commences as planned in the application.

235. The CEC would not object to the Commission conditioning its approval on FEI simultaneously evaluating the use of robotic tools during project implementation with the view to implementation if proven to be cost effective.

[124] FEI Final Argument page 28
[125] Exhibit B-5, CEC 1.21.1.5
[126] Exhibit B-5, CEC 1.21.2

Environment and Archaeological Impacts

236. In its Final Argument FEI states that the Project is expected to have minimal environmental and archaeological impact.[127]

237. Hemmera Envirochem Inc. completed an Environmental Overview Assessment (Appendix O) which determined that the environmental risk is low.

238. Stantec completed an Archaeological Overview Assessment (Appendix P) which identified areas of low, moderate or high potential impact areas.

239. FEI has committed to managing the environmental and archaeological issues according to the professional specifications recommended in the reports.

240. The CEC has reviewed the evidence related to the Environmental and Archaeological impacts and submits that there are no significant concerns that should jeopardize the Project plan.

241. The CEC recommends that the Commission accept FEI's project plan related to environmental and archaeological impact activities as proposed by FEI.

Public Consultation and Engagement with Indigenous Communities

Public Consultation

242. FEI's approach to public consultation was presented in its application and is outlined in FEI's Final Argument in Part 6A.

243. FEI tailored its consultation to each stakeholder group including residential customers, industrial customers and local governments.

244. FEI has identified only three major concerns.

245. The CEC has reviewed the evidence related to public consultation and is satisfied with the depth and breadth of this engagement.

246. The CEC recommends that the Commission find the public consultation to be adequate.

247. FEI's approach to Engagement with Indigenous Communities was presented in its application and is outlined in FEI's Final Argument in Part 6B.

[127] FEI Final Argument

Deferral Account

248. FEI is requesting approval of deferral treatment of the Application and Preliminary Stage Development Costs for the Project.[128]

249. FEI is seeking approval of a new non-rate base deferral account, to capture the application and preliminary stage development costs of the Project, including legal review, consultant costs, BCUC costs and BCUC-approved intervener costs.[129]

250. FEI proposes that the account attract FEI's weighted average cost of capital until it enters rate base.[130]

251. 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.[131]

252. FEI forecasts the December 31, 2019 net-of-tax balance for the Application cost and the Preliminary Stage Development cost are to be $0.293 million and $0.698 million, respectively.[132]

253. The proposed three-year amortization period for the Application and Preliminary Stage Development Costs deferral is primarily based on recent similar deferral accounts approved for recent CPCN applications. FEI believes either a one or two-17 year amortization period would also be appropriate.[133]

254. FEI states the amortization of the deferral costs will begin in 2020, will be combined with project delivery costs and will impact customer delivery rates incrementally in each year from 2020 to 2025,[134] with an increase to the approved RRA averaging .71% annually.[135]

255. The CEC notes that the proposed Application and Preliminary Stage Development Costs deferral is consistent with other recent CPCN applications.

256. The CEC submits that when combined with the project delivery costs that deferral will have a minimal effect on rates.

257. The CEC recommends that the Commission accept the proposed deferral account as proposed by FEI.

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[128] Exhibit B-1, page 83
[129] FEI Final Argument, page 46
[130] FEI Final Argument, page 46
[131] FEI Final Argument, page 47
[132] Exhibit B-1, page 86
[133] Exhibit B-2, response to BCUC IR 25.2
[134] Exhibit B-1, page 87
[135] Exhibit B-1 page 87

Recommendations

258. The CEC finds FEI's proposal to upgrade the 29 Transmission Laterals to necessary safety standards is in the public interest, and recommends approval by the Commission.

259. The CEC recommends that the Commission consider the option of conditioning its approval on having FEI conduct additional work quantifying risk and prioritization activities and reporting to the BCUC such that the Commission can ensure that the project is undertaken in the most cost-effective manner possible.

260. The CEC submits that it could potentially be beneficial for the utility to examine the value of a staged option, under which FEI would conduct further quantitative analysis on an ongoing basis to:

- Assess the condition of the laterals and establish priorities with a quantitative evidentiary base;
- Examine the potential for deferral of upgrades to certain laterals either to promote cost savings based on timing or enable alternative technologies to advance to commercial viability;
- Further examine whether or not PRS could be reasonably provided at greater cost-effectiveness in some instances.

261. The CEC would not support a project deferral that could unreasonably increase the risk of significant negative consequences which jeopardize the safety or well-being of any community or individual, create irreversible harm to the environment, or result in customer service disruptions or widespread outages.[136]

262. However, FEI has provided evidence that the pipelines can currently be considered safe[137], and the Company employs an Integrity Management Program for Pipelines using available methods to mitigate the risk.[138]

263. The CEC accepts that the IGU project, or some version thereof, is necessary to maintain compliance with legal and regulatory obligations.[139]

264. The CEC would also not support a deferral which resulted in FEI failing to meet regulatory standards and best practices in a timely manner.

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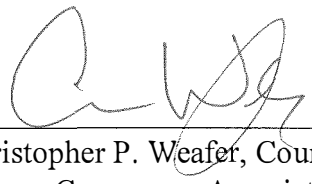
[136] Transcript page 9
[137] Exhibit B-5, CEC 1.18.1 and 1.18.2
[138] Exhibit B-5, CEC 1.18.1
[139] Exhibit B-5, CEC 1.18.2

265. The CEC recommends that the Commission accept the proposed deferral account as proposed by FEI.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

David Craig

David Craig, Consultant for the Commercial Energy Consumers Association of British Columbia



Christopher P. Weafer, Counsel for the Commercial Energy Consumers Association of British Columbia