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June 7, 2019

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598988

Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project (the Application)

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

On December 17, 2018, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-79-19 setting out a further Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

34. Reference: Exhibit B 5, CEC 1.1.3 and 1.3.2 and 1.3.4

As such, FEI's approach to system-wide corrosion monitoring for its pipelines is as follows. Taken as a whole, this approach addresses all FEI pipelines.

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.

1.3.2 If yes, please identify the areas in which FEI expects to see similar concerns.

Response:

Please refer to the response to CEC IR 1.1.3. FEI has identified external corrosion as a potential hazard to its entire buried steel pipeline system. Please also refer to BCUC IR 1.4.1 for FEI's assessment of the potential for active corrosion on cathodically protected pipelines in its system.

1.3.4 If FEI is expecting to experience similar issues in significant portions of its remaining transmission pipelines, is the current CPCN application part of a larger overall project that is not yet before the Commission? Please explain.

Response:

No, this Application is not part of a larger overall project that is not yet before the BCUC. Please refer to the responses to CEC IRs 1.1.2 and 1.1.3. It is possible in the future, however, that FEI may prioritize investment for providing ILI capability or other integrity management solutions for transmission pipelines operating at 30 percent SMYS or greater that are less than NPS 6 if the appropriate technology were to become proven and commercialized and industry standard practice were to include these smaller diameter pipelines.

34.1 Please provide the number of pipelines lower than NP6 and operating at greater than 30% SMYS.

Response:

FEI has 71 pipelines smaller than NPS 6 and operating at greater than 30 percent of SMYS, as listed in the response to BCUC IR 1.8.2, Table 5.

34.2 What, if any, technologies has FEI identified to date that are expected to be available for pipelines smaller than 6 NPS in the future, if any?

Response:

At this time, FEI has not identified any proven and commercialized technology for external corrosion monitoring on pipelines smaller than NPS 6.

As stated in the response to BCOAPO IR 1.1.1, for laterals that are less than NPS 6 and above 30 percent of SMYS, FEI currently employs Modified ECDA and will continue to monitor available technology and industry practice for mitigating the potential for rupture due to corrosion. FEI considers this approach as appropriate considering the technology available and current industry practice.

34.3 Does FEI intend to introduce some form of in-line inspection or other technology in all its pipelines operating at greater than or equal to 30% SMYS, including NPS less than 6, when such technologies becomes available?

Response:

FEI intends to continue to monitor available technology and industry practice for mitigating the potential for rupture due to external corrosion. If proven and commercialized technology becomes available and adopted by industry, FEI would be obligated to evaluate the use of such technology to mitigate identified hazards to its pipeline system and would make a decision at that time whether to introduce the in-line inspection or other technology for its pipelines.

34.3.1 If no, please quantify the number of pipelines that FEI expects to fit with ILI or other technology.

Response:

FEI has no current expectations regarding the number of pipelines that may be fitted with ILI or other technology in the future. Please refer to the response to CEC IR 2.34.3.

34.4 Please provide a ballpark cost of installing ILI or other technology in the remainder of pipelines that FEI expects to modify for corrosion monitoring.

Response:

FEI is not aware at this time of any other proven, commercialized technology being adopted by Canadian natural gas transmission pipeline operators for external corrosion monitoring on pipelines sized less than NPS 6, nor is it apparent when such technology may become available, proven, commercialized, and adopted. Therefore, FEI is unable to speculate on the system modifications that may be required for a hypothetical, future external corrosion monitoring program and is unable to provide a ballpark estimate or a quantitative cost/benefit analysis.

34.5 Does FEI intend to conduct a quantitative cost/benefit analysis for doing so?

Response:

Please refer to the response to CEC IR 2.34.4.

34.5.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 2.34.4.

34.5.2 If yes, would FEI conduct the assessment itself or utilize specialized risk assessment professionals? Please explain.

Response:

Please refer to the response to CEC IR 2.34.4.

35. Reference: Exhibit B-5, CEC 1.3.2

> 3.2 Please discuss the potential consequences of a rupture.
>
> **Response:**
>
> As discussed in Section 3.3.4 of the Application, a natural gas pipeline rupture has the potential to result in significant safety, reliability, environmental and regulatory consequences. The following discusses these consequences.
>
> - Safety Consequences: As noted in Section 3.3.4 of the Application, 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. The following is an excerpt from a Gas Research Institute Report GRI-00/0189, A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines, 2001, prepared by C-FER Technologies:
>
>   "The rupture of a high-pressure natural gas pipeline can lead to outcomes that can pose a significant threat to people and property in the immediate vicinity of the failure location. The dominant hazard is thermal radiation from a sustained fire (…)."

35.1 What pressures are considered to be 'high pressure' pipelines?

Response:

The referenced report (GRI-00/0189) does not contain an explicit definition of "high pressure"; however, Table 3.1 "Summary of relevant North American pipeline failure incident reports" includes incidents ranging from 497 psi (approximately 3430 kPa) to 1207 psi (approximately 8320 kPa). The operating pressures of the 29 Transmission Laterals fall within this range.

36. Reference: Exhibit B-2, BCUC 1.4.2 and 1.12.6

> 4.2 For each of the 29 Transmission Laterals, please identify any control digs (i.e. digs where there has been no indication of potential corrosion from the above-ground surveys).
>
> **Response:**
>
> FEI has not performed control digs on any of the 29 Transmission Laterals. FEI does not consider that random control digs provide sufficient value as they are not targeted to a specific site for the purposes of addressing any particular integrity concern.
>
> As such, FEI has characterized many of its estimates in the table below as "minimums". Additionally, future recurring digs required by the ANSI/NACE ECDA standard are not included in this table.
>
> The table below also includes the percentage of the integrity digs prescribed under the ANSI/NACE ECDA standard that would be control digs, as requested by BCUC IR 1.12.6.1. It also includes the number of digs identified by FEI's application of its Modified ECDA standard, as requested by BCUC IR 1.12.7.

36.1 Please confirm that a random control dig would cost approximately the same as an 'integrity' dig.

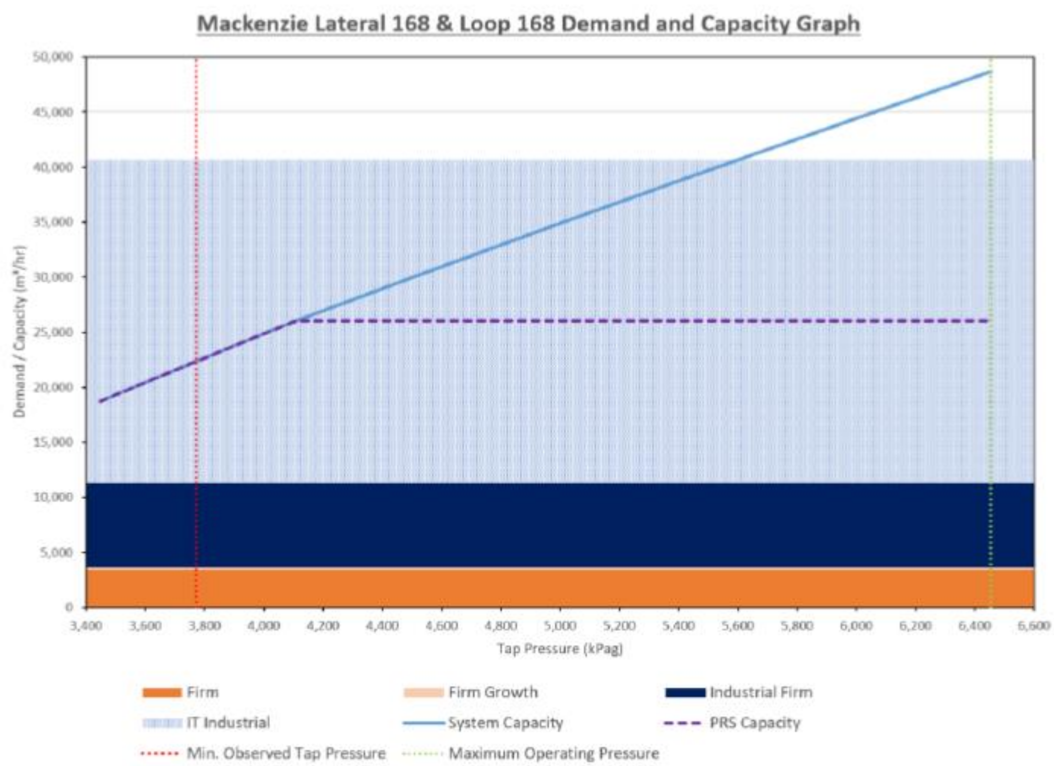
Response:

Confirmed. FEI would expect both random control digs and integrity digs to cost approximately the same assuming similar variables such as local conditions (soil type, land slope, access constraints, etc.) and dig site location.

37. Reference: Exhibit B-2, BCUC 1.14.3

The graphs below expand on the information provided in the table in the response to BCUC IR 1.14.2, and separate out current firm customers' demand, forecasted growth in firm demand, industrial firm, and industrial interruptible (IT) in a stacked bar format that illustrates the cumulative demand. The information is grouped by lateral system. Note that in the lower pressure ranges in the capacity graphs below, the PRS capacity and the system capacity (without PRS) intersect and then at all lower pressures the PRS capacity and the system capacity follow the same declining capacity curve. The region of the graph where the two curves coincide indicates the operating conditions where the control valve would be fully open due to upstream pressures less than the set point (29.9 percent SMYS) of the PRS. In this operating area, the PRS is not limiting the capacity of the system. For the same reasons (because the control valve is fully open), any capacity upgrades that might be required to increase capacity to serve future increases in firm demand for tap pressures in this range would be no different in scale or scope with or without PRS and could not be addressed, for example, by removing the PRS.

MacKenzie System:



37.1 Please explain the causes of tap pressure changes.

Response:

The tap pressure experienced at the tap location supplying any FEI lateral is primarily determined by the operation of the upstream transmission system. The upstream pipeline operator operates their pipeline under a range of conditions to meet delivery volume and delivery pressure requirements at all critical points and customer receipt locations along their pipeline system. This is achieved while also optimizing their delivery costs and meeting the operations and maintenance requirements on their own system. Tap pressures vary when there are changes in the upstream transmission system such as changes in customer demand on a daily or seasonal basis, whether upstream compressor stations are operating or not to maintain required pressures, and whether portions of the upstream system are undergoing inspection or maintenance. Tap pressures are expected to be variable, but under normal circumstances on a day-to-day or seasonal basis, they vary in a predictable way and in a narrower range than the maximum or minimum values indicated on the Demand and Capacity Graph in the preamble to this information request.

37.2 Does FEI normally operate at maximum operating pressure on each lateral, or does that change from time to time? Please explain.

Response:

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 at the minimum contractual pressure). Please refer to the response to CEC IR 2.37.1 for an explanation of the causes for the changes in operating pressure.

37.3 Does the stacked bar chart represent the maximum demand experienced by the transmission lateral, average value, or other value? Please clarify.

Response:

The stacked bar charts represent the maximum demand experienced by the transmission system and includes demand of customers forecast to be connected to the system in the forecast period (Firm Growth). In the MacKenzie System example above, the Firm Growth is very small relative to the existing Firm and Industrial demands and is not clearly distinguishable in the chart.

37.4 The CEC notes that in the Mackenzie system, the demand exceeds the system capacity line at all tap pressures below 5,600kPag. Does the Mackenzie system or other lateral ever operate below 5,600 kPag?

Response:

Yes. At times, the MacKenzie lateral will operate below 5600 kPag. The pressure in the system varies for reasons such as those outlined in the response to CEC IR 2.37.1. Other lateral systems may operate below 5600 kPag as well, but they operate independently of the MacKenzie System.

37.4.1 If yes, please comment on how the system capacity line exceeding the demand affects customer experience, if at all.

Response:

The system capacity line exceeding the demand indicates that the maximum demand of all customers can be met and that customers would experience no constraints on their ability to consume gas. Conversely, when the demand exceeds the system capacity line, this indicates not all customers can take their maximum demand. In this circumstance, the demand of customers with interruptible rate schedules may need to be managed to ensure their consumption added to the consumption of existing firm customers does not exceed the lateral system capacity. Under this system condition, interruptible customers may experience curtailment to achieve the required demand management.

37.5 Does FEI always operate at tap pressures which exceed its demand on the 29 laterals? Please explain.

Response:

Tap pressures vary within a range. When the lateral system is served by an upstream transmission pipeline company, the tap pressure within that range may be determined by factors outside of the direct control of FEI as described in the response to CEC IR 2.37.1. FEI therefore ensures that each of the 29 Transmission Laterals has the capacity, even at a minimum tap pressure, to meet the forecast firm demand of its downstream customers. For lateral systems supplied by companies other than FEI, this minimum pressure will often be a contractual lower value that the upstream operator is obligated to meet or exceed. For lateral systems fed from FEI's Interior Transmission System, the minimum pressure is determined by the design constraints in place on that larger system. Should the firm demand forecasted exceed the lateral system's capacity (at the minimum tap pressure) at any point within the forecast, FEI will identify system capacity upgrades to be designed and installed before the demand exceeds the available capacity. This ensures FEI maintains, at all times, the capacity to meet the delivery requirements of all firm customers served by the system.

37.6 The CEC would like to understand how often interruptible customers currently experience interruptions on the laterals and how this would change if PRS were implemented. For each transmission lateral in which the PRS option has been screened out due to capacity issues, please provide the historic demand by month for the last five years in graph format for each year.

Response:

The lateral systems where PRS was screened out due to capacity issues include the following:

- The MacKenzie System
  - MacKenzie Lateral 168
  - MacKenzie Loop 168
  - Feeds the downstream BC Forest Products Lateral 168
- The Prince George 1 System
  - Prince George 1 Lateral 168
  - Feeds the downstream Prince George Pulp Lateral 168 and the Husky Oil Lateral 168

- The Kamloops 1 System
  - Kamloops 1 Lateral 168
  - Kamloops 1 Loop 168
- The Salmon Arm System
  - Salmon Arm Loop 168
  - Feeds the downstream Salmon Arm 3 Lateral 168
- The Cranbrook Kimberly System
  - Cranbrook Lateral 168 and Cranbrook Loop 219
  - Cranbrook Kimberley Loop 273
  - Cranbrook Kimberley Loop 219 and Kimberley Lateral 168
  - Skookumchuck Lateral 219
- The Fording System
  - Fording Lateral 219
  - Fording Lateral 168
  - Feeds the downstream Elkview Lateral 168

The historic demand by month would not be helpful in understanding of the frequency of interruption or curtailment of interruptible capacity on a lateral as historical demand on these systems is more a function of the tap pressure and flows on a daily and even hourly basis. As FEI does not maintain records which provide the dates and durations of historic calls for curtailment of interruptible customers associated with insufficient capacity on the lateral, it cannot provide the requested historic demand by month identifying the date and duration of interruptions.

Of the six lateral systems identified, two systems, the Salmon Arm system and the Cranbrook Lateral 168 and Loop 219 in the Cranbrook Kimberly system, could not meet the current and forecasted firm demand on the system if a PRS was installed. Consequently, a PRS installation was excluded in these cases as it would not allow FEI to meet its firm demand obligations within the forecast period and is not related to service provided to interruptible customers. The impacts to interruptible customers on the remaining four laterals for the five years from January 31, 2014 to December 31, 2018 is discussed in detail in the response to CEC IR 2.37.6.2.

37.6.1 Please identify when interruptions were experienced and the duration of interruptions on the above graphs or other format if appropriate.

Response:

Please refer to the response to CEC IR 2.37.6.

37.6.2 Using an average of the last five years for demand, please plot the interruptions that would occur under a PRS option.

Response:

As described in the response to CEC IR 2.37.6, FEI does not have records that detail historical interruptions. To provide an understanding of the potential impact a PRS could have on the lateral systems identified in the response to CEC IR 2.37.6, FEI reviewed the tap pressure and Interruptible customer flow rates in the period between January 1, 2014 and December 31, 2018. Although there is no record of instances of curtailment, these lateral systems are actively managed to stay within the current available capacity. Therefore, the actual customer flows reviewed may already have been lower than typical in many instances due to curtailment that may have been in place.

The following provides a summary for each lateral system describing the change in the number or days these customers may be subject to curtailment using the pressures that were experienced over the 5 year history if the Firm customers served by the lateral system had been at peak demand and a PRS had been installed operating at 29.9 percent SMYS. As the potential for the Firm customers on the system to be at peak is only expected to occur during the months of November through the end of February, only the data for that period was included in the review. This summed to 601 winter days in that 5-year period.

The MacKenzie System:

PRS at MacKenzie Lateral System Tap	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment Potential (tap pressure <5599 kPa)	566
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (tap pressure between 4110 and 5599 kPa)	472

Over this period there would be 566 days where curtailment potential would have existed had all customers been at peak demand. With a PRS in place, all 601 days would have had curtailment potential, 35 days more than without a PRS. Of the 566 days that had some curtailment potential without PRS, 472 of those days would have required a greater degree of curtailment with a PRS. Based on a review of the recorded tap pressure during this 5-year period, there were 92 days when the tap pressure was below the PRS set point of 4110 kPa and could require the same degree of curtailment with or without a PRS. Based on the recorded industrial demand during the same 5 year period there were 2 days where the interruptible customers would be curtailed to a greater degree with PRS (tap pressures were between 4110 kPa and 5599 kPa and the measure industrial flow was higher than the current lateral capacity, and much higher than the capacity with PRS) and an additional 5 days where curtailment could have been required only because a PRS was in place (tap pressures were >5599 kPa, where the current lateral has capacity for all customers peak demand, but the measured industrial flow was higher than the capacity available with PRS). 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. 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 option for the MacKenzie Lateral.

The Prince George 1 System:

PRS at Prince George 1 Lateral 168 Tap	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment Potential	601
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (tap pressure > 4110 kPa)	600

For the Prince George 1 Lateral, the Interruptible customers have curtailment potential for the entire period with or without PRS, but would have had a greater degree of curtailment required with a PRS for all but 1 of the 601 days. Reviewing the recorded tap pressure and industrial flow during this 5 year period, there were 52 days when the tap pressure was below the PRS set point of 4110 kPa and could require the same degree of curtailment with or without a PRS. There were 2 days based on recorded flows of interruptible customers where those customers would be curtailed to a greater degree with PRS (tap pressures were lower and the measured industrial flow was higher than the current lateral capacity, and much higher than the capacity with PRS) and an additional 41 days where curtailment could have been required only because a PRS was in place (the tap pressures were high enough that the current lateral had capacity for the measured industrial flow, but would not have had sufficient capacity with PRS). 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.

The Kamloops 1 System:

PRS at Kamloops 1 Tap	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment Potential (tap pressure < 4257 kPa)	412
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (tap pressure between 4122 kPa and 4257 kPa)	0

Over this period, there would be 412 days where curtailment potential existed had all customers been at peak demand. With a PRS in place, all 601 days would have had curtailment potential, 189 days more than without a PRS. Based on a review of the recorded tap pressure and industrial flow during this 5-year period, there were 353 days when the tap pressure was below the PRS set point of 4122 kPa and could require the same degree of curtailment with or without a PRS. There were no days based on recorded flows of interruptible customers where those customers would be curtailed to a greater degree with a PRS. This is a result of one of the larger customers not operating at their full capacity in recent years. 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.

The Cranbrook Kimberley System:

As discussed in the response to CEC IR 2.37.6 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. The tap locations further downstream do not impact capacity to serve Firm customers, but do impact interruptible customers so the discussion for those laterals in the Cranbrook Kimberley system follows.

For the 3 locations that follow, the difference in curtailment potential with or without PRS is the same; however, the number of days in the third row of each table varies, because of the location of the PRS relative to the TCPL and the associated pressure drop between the tap and PRS under peak demand, and the differences in the set point of each PRS.

PRS at Cranbrook Kimberly Loop 273	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment potential (TCPL tap pressure <5713 kPa)	593
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (TCPL tap pressure between 4874 and 5713 kPa)	151

PRS at Cranbrook Kimberly Loop 219/Lateral 168	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment potential (TCPL tap pressure <5713 kPa)	593
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (TCPL tap pressure between 4549 kPa and 5713 kPa)	363

PRS at Skookumchuck Tap	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment Potential (TCPL tap pressure <5713 kPa)	593
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (TCPL tap pressure between 5414 kPa and 5713 kPag)	5

Over this period there would be 593 days where curtailment potential existed had all customers been at peak demand. With a PRS in place, all 601 days would have had curtailment potential, 8 days more than without a PRS. Of the 593 days that had some curtailment potential, without PRS between 5 and 363 of those days, dependent on location and station set point requirements, could have required a greater degree of curtailment required with a PRS. Based on a review of the recorded tap pressure and industrial flow during this 5-year period, were no days based on recorded flows where the interruptible customers would be curtailed to a greater degree with PRS. This is a result of one of the larger customers not operating at their full capacity within the November to February time period recent years. 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 there peak demand coincide with the winter period.

The Fording Lateral System:

PRS at Fording Lateral Tap	
Nov 1 to Feb 28 2014-2018	
Days with Curtailment Potential (TCPL tap pressure <5500 kPa)	473
Days with Curtailment Potential with PRS (all days)	601
Days with some Curtailment Potential with or without PRS but Potential is greater with PRS (TCPL tap pressure <5500 kPa)	473

Over this period, there would be 473 days where curtailment potential existed had all customers been at peak demand. With a PRS in place, all 601 days would have had curtailment potential, 128 days more than without PRS. Of the 473 days that had some curtailment potential without PRS, all 473 days could have required a much greater degree of curtailment required with PRS. Based on a review of the recorded tap pressure and industrial flow during this 5-year period, there were 465 days based on recorded flows of interruptible customers where those customers would be curtailed to a greater degree with PRS (tap pressures were lower and the measured industrial flow was higher than the current lateral capacity, and much higher than the capacity with PRS) and an additional 125 days where curtailment could have been required only because a PRS was in place (the tap pressures were high enough that the current lateral had capacity for the measured industrial flow, but would not have had sufficient capacity with PRS). 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 Fording Lateral.

38. Reference: Exhibit B-5, CEC 1.5.2

5.2 What is causing the CP shielding on FEI's system? Please explain.

Response:

FEI believes that the quality of coating application and type of coatings applied in the past has resulted in observed coating disbondment, which has contributed to CP shielding on FEI's pipeline system. FEI has also found CP shielding due to the presence of rocks and foreign structures in the backfill adjacent to the pipeline, which can both damage the coating and/or prevent CP current from reaching the pipeline.

38.1 Does FEI undertake to pinpoint areas that its pipelines might be expected to have CP shielding either because of the timing of the pipeline coating application, the geographic characteristics of the terrain, or other circumstances that lead to shielding?

Response:

No, 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.

The situations where CP shielding can occur, such as where coating has disbonded or where rocks are near or in contact with the buried pipeline, may either be systemic or occur randomly along the length of a pipeline.

As demonstrated by the integrity dig data included in FEI's response to BCUC IR 1.4.1, evidence of CP shielding on FEI's transmission pipelines exists across a range of pipeline ages and coating types. As discussed in the Application, the indirect inspection surveys of an ECDA or Modified ECDA are not capable of detecting corrosion in areas where CP shielding occurs.

38.1.1 If yes, please explain when and how often this effort is undertaken.

Response:

Please refer to the response to CEC 2.38.1.

38.1.2 If yes, please comment on how FEI uses this information.

Response:

Please refer to the response to CEC 2.38.1.

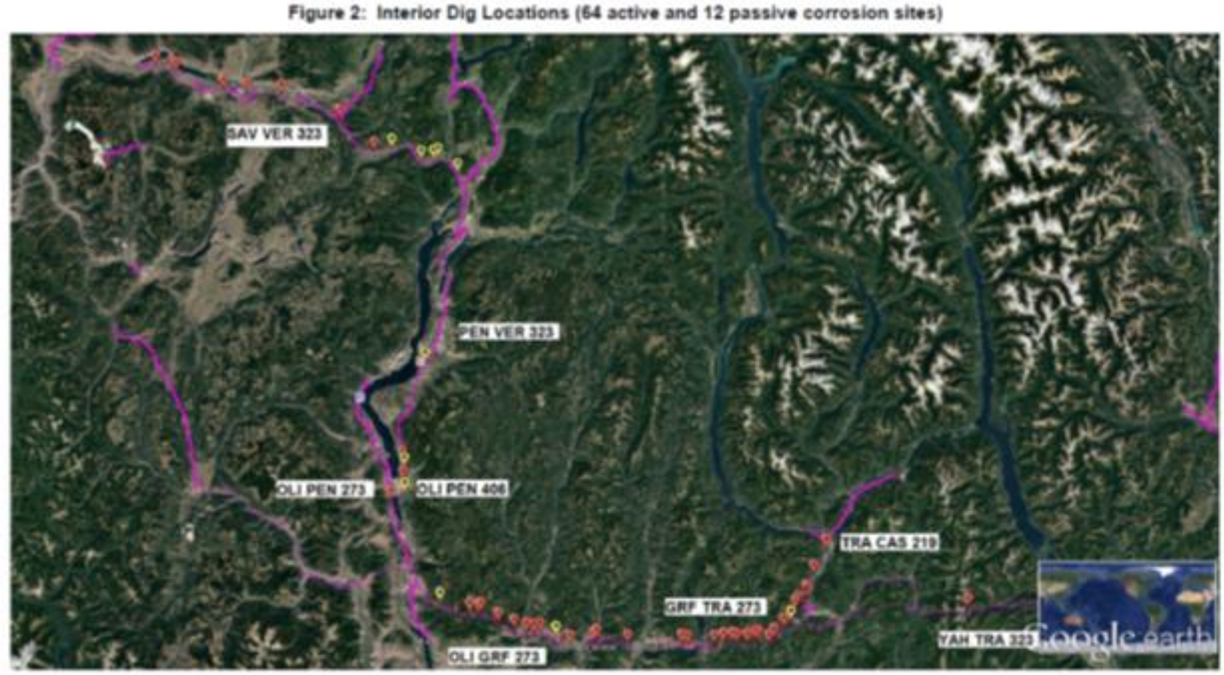
38.1.3 If no, please explain why not.

Response:

Please refer to the response to CEC IR 2.38.1.

39. Reference: Exhibit B-5, CEC 1.10.1

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



39.1 Please explain the difference between passive corrosion and active corrosion.

Response:

The term passive corrosion is used to describe corrosion (e.g. rust) on a pipeline that, based on the observations of a qualified analyst during an integrity dig, is considered to have occurred at some time in the past and is no longer actively progressing. The term active corrosion is used to describe corrosion that is considered to be growing at the time of observation.

Factors that could contribute to active corrosion becoming passive include changes to groundwater conditions or improvements to a previously sub-optimally performing cathodic protection system.

39.2 Were any integrity digs conducted on the Fording Lateral?

Response:

Please refer to the response to BCUC IR 2.39.3.2.

39.2.1 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.39.3.2.

40. Reference: Exhibit B-5, CEC 1.18.1

> 18.1 Is it FEI's contention that the transmission laterals are currently unsafe?
>
> <u>Response:</u>
>
> No, it is not FEI's contention that the 29 Transmission Laterals are currently unsafe. As part of its Integrity Management Program for Pipelines, FEI uses a number of available methods including, but not limited to, recurring operational activities such as leak survey and pipeline patrol as well as integrity monitoring through Modified ECDA to mitigate the risk of failure on the 29 Transmission Laterals. However, given the known limitations of these methods to detect external corrosion where there is cathodic protection shielding, the identified potential for pipeline rupture, the availability of mitigation solutions and, in particular, the common use of ILI for smaller diameter pipelines in the industry, FEI has concluded that steps should be taken to mitigate the potential for rupture due to external corrosion.

40.1 Could the project be safely deferred for a period of time such as 2 years, 5 years or longer?

<u>Response:</u>

No. For FEI to be compliant with its legal and regulatory obligations, to be consistent with industry practice, and to address identified time-dependent risks to its pipeline system, the IGU Project could not be safely deferred for a period of time such as 2 years, 5 years or longer. FEI has proposed the IGU Project to proactively address the potential for rupture of the 29 Transmission Laterals. FEI proposed the Project on the basis of:

1. The 29 Transmission Laterals are subject to failure by rupture (refer to section 3.3.3 of the Application);
2. Pipeline ruptures can result in significant consequences, including serious injuries or worse to employees or the public (CEC IR 1.3.2);
3. Most transmission pipeline failures are due to external corrosion (section 3.3.1 of the Application and CEC IR 1.9.3);
4. 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);
5. Undetectable external corrosion (due to CP shielding) has previously been observed on 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

6. 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).

Proven and commercialized in-line inspection technology exists for the mitigation of external corrosion on these pipelines, and alternative options are available to mitigate the consequences of failure where these have been demonstrated to provide more value (e.g. technically feasible, cost-effective compared to other alternatives).

Lastly, the IGU Project is necessary to maintain compliance with FEI's legal and regulatory obligations (CEC IR 1.18.2). As such, FEI has no basis upon which to determine a safe period of time for deferring the IGU Project.

40.1.1 If yes, over what period of time could the project be safely deferred? Please explain why.

Response:

Please refer to the response to CEC IR 2.40.1.

40.1.2 If no, please explain why not.

Response:

Please refer to the response to CEC IR 2.40.1.

40.2 Please calculate the potential savings for deferring the capital expenditures for a period of 5 years.

Response:

As stated in the response to CEC IR 2.40.1, for FEI to be compliant with its legal and regulatory obligations, to be consistent with industry practice, and to address identified time-dependent risks to its pipeline system, the IGU Project could not be safely deferred for a period of time such as 2 years, 5 years or longer.

When taking into account inflation of project costs and assuming no additional capital expenditures or other incremental costs in the near-term because of deferral of the project, FEI customers would experience some savings on a net present value (NPV) basis. <u>This conclusion is based on the assumption that the discount rate in the NPV analysis is greater than the rate of project cost inflation.</u> However, FEI has not conducted this financial analysis as it would be speculative and would not provide any benefit to address the underlying need of the IGU Project.

41. Reference: Exhibit B-5, CEC 1.23.3

> 23.3 What are FEI's responsibilities to its interruptible customers, and how would this be impacted by reducing operating pressure?
>
> <u>Response:</u>
>
> As per its BCUC approved tariff, FEI is permitted to curtail or restrict gas supply to interruptible customers, for example, under colder weather conditions when core customers' demand increases. At the same time, interruptible customers expect FEI to provide a reasonable level of reliable service for the majority of the year. If these customers were curtailed or restricted too frequently, they would seek alternate fuels that they may view as more reliable and FEI could lose the customer and the load permanently.
>
> PRS was not determined as a feasible solution for some laterals as the PRS would cause a reduction in capacity on those laterals and would result in a year round requirement for more frequent curtailment of customer loads such that FEI not would not be providing a reasonable level of reliable service. In some instances, a PRS would mean FEI could not meet supply needs for forecasted growth in the region served by those laterals. In those instances, PRS could not be done without also requiring a pipeline expansion to restore capacity on that lateral as it could no longer handle expected customer loads. Please refer to the customer impacts summarized in the response to CEC IR 1.23.1 for additional information.

41.1 Does FEI have a contracted threshold with its customers defining whether or not it can restrict or curtail gas supply to interruptible customers? Please explain.

<u>**Response:**</u>

FEI's rate schedules offer different levels of service to its customers. FEI offers firm, interruptible, and a combination of firm and interruptible service. Most contracted industrial customers that are served directly off the FEI transmission system receive a combination of firm and interruptible service. Therefore, there is usually some amount of contracted firm capacity for these industrial customers.

FEI's obligation to interruptible customers is that if at anytime FEI, acting reasonably, determines there is insufficient capacity on the system to accommodate the customer's request for interruptible capacity, FEI may for any length of time, interrupt or curtail transportation service.

If interruptible customers perceived that they were not receiving a reasonable level of reliable service for the majority of the year, then they could switch some or all of their load to alternate fuels, or request firm service. If an interruptible customer switched its load to alternative fuels, other firm customers would no longer receive the benefits of interruptible revenue (i.e., reduced costs from the increased utilization of a pipeline that was generally designed for firm load under peak conditions). Similarly, if an interruptible customer switched to firm service, this may require FEI to invest in upgrades to its system to provide firm service.

41.2 Please briefly elaborate on customers' expectation of a 'reasonable level of reliable service for the majority of the year'.

Response:

FEI's interpretation of its interruptible customers' expectation of a reasonable level of reliable service for the majority of the year is that they expect interruptions or restrictions to be limited to the amount of interruptible capacity available to them under peak weather conditions or during times of maintenance work.

41.3 What alternative fuels might the customers migrate to if they were curtailed or restricted too often?

Response:

Customers might consider alternative fuels such as coal, oil, wood/biomass, and electricity.

42. Reference: Exhibit B-5, CEC 1.30.2

30.2 Has the natural gas system had reliability issues in the affected laterals? Please explain and provide evidence of the reliability issues.

Response:

FEI has identified the following recorded incidents involving release of gas from its operating history of the 29 Transmission Laterals that may have impacted their reliability. Beyond what is provided in the table below, FEI has not located further details of the reliability impacts for these occurrences.

Year	Pipeline	Cause of Failure	Failure Type	Notes from Available Documents
1973	Fording Lateral 168/219	Third party damage	Leak	A bulldozer hit the pipeline
1976	Castlegar Nelson 168	Natural hazard	Leak (assumed)	Mud and rock slide damaged NPS 6 transmission line. "A line break 6" Inland Natural Gas line in the vicinity of Roson near Selkirk College occurred April 7. Will lose 150 customers at Robson and will lose Selkirk College, and feed Nelson by line pack supplemented by propane storage line."
1977	Castlegar Nelson 168	Third party damage	Leak	A grader hit the pipeline. The pipeline failure was repaired with a plidco high pressure sleeve and continued in operation at reduced pressure.
1982	Fording Lateral 168/219	Third party damage	Leak	A road grader dug a hole into the NPS 6 pipeline buried on the road right-of-way. No one was injured. No damages. 6 to 7 feet of NPS 6 pipe was welded in and x-rayed.
1983	Prince George 1 Lateral 168	Third party damage	Rupture	Rupture of NPS 6 TP Lateral caused by caterpillar tractor Tractor operator thrown clear by rupture. No fatalities.
1984	Castlegar Nelson 168	Natural hazard	Leak (assumed)	Mud slide hit the pipeline
1986	Kamloops 1 Loop 168	Human error	Leak	Faulty weld
1988	Trail Lateral 168	Human error	Leak	Back-hoe hit (hired by Inland Natural Gas)
1992	Salmon Arm Loop 168	Third party damage	Leak	BC Hydro auger punctured pipeline Section of pipeline was cut-out
1996	Fording Lateral 168/219	External corrosion	Leak	Leak detected during routine leak survey.

42.1 The CEC notes that leaks have not been identified since 1996. Please explain what changes occurred that leaks have not been detected after this period.

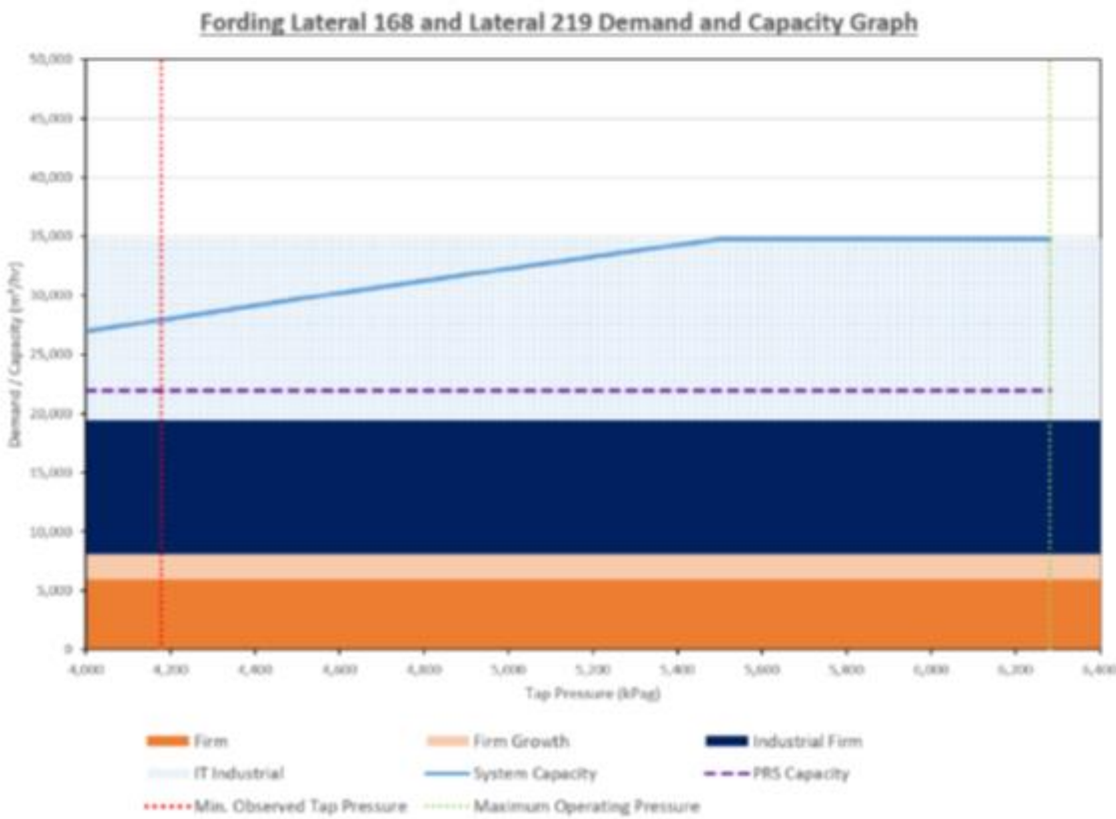
Response:

Although FEI has not noted changes to its field operational practices 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.

43. Reference: Exhibit B-2, BCUC 1.14.3

Fording System:



The Fording Lateral System is comprised of the Fording Lateral 219 which is partly looped by the Fording Loop 114 from the tap location to a location south of the community of Sparwood. At the end of the Fording Lateral 219 north of Sparwood, the Fording Lateral 168 continues on northward past the community of Elkford to serve large industrial mine sites. The Fording system feeds Gate Stations serving the communities of Sparwood and Elkford and several large industrial sites located at various points along the length of the system. The large industrial customers (mostly mining sites) have large firm industrial and interruptible loads and are currently actively managed year round to keep the interruptible demand within the available capacity of the system. The capacity graph above shows that the installation of a PRS at the TransCanada Pipeline (TCPL) Tap to the system would severely diminish the capacity available for these existing large volume customers. As a result of a PRS impacting the established operations of existing FEI customers, PRS was considered not viable for the Fording Lateral 219 and Fording Lateral 168.

43.1 The CEC notes that the Fording Lateral System capacity just meets its load at maximum operating pressure. Does FEI expect to increase the capacity of the lateral within the next 10 years? Please explain why or why not.

Response:

FEI has no current plans to increase the capacity of the lateral within the next 10 years.

FEI is in discussions with a large industrial customer about their longer-term needs regarding natural gas use and the capacity of the Fording Lateral. The customer has not increased their firm contracted capacity; however, they continue to add load to the system and are currently relying on available interruptible capacity. Any upgrades to accommodate firm load increases for this customer if they were to occur, would likely involve loops of the existing pipeline at various locations for small portions of the total length of the pipeline and therefore would not impact ILI being the preferred alternative for the Fording lateral system.

43.2 Please provide a discussion of FEI's obligation to serve interruptible customers.

Response:

Please refer to the response to CEC IR 2.41.1 for a discussion of FEI's obligation to serve interruptible customers.