Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604)576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
www.fortisbc.com

May 13, 2021

Residential Consumer Intervener Association
c/o Midgard Consulting Inc.
Suite 828 – 1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Mr. Peter Helland, Director

Dear Mr. Helland:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599152

Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project (Application)

Response to the Residential Consumer Intervener Association (RCIA) Information Request (IR) No. 2

On November 16, 2020, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-97-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to RCIA IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

Table of Contents **Page no.**

A. Project Need and Justification

27. Reference: Exhibit B-2, FEI Response to BCUC IR1, IR 6.2

"FEI notes that the LHA HHF growth rates were applied to all residential customers equally and that this approach does not account for the differences between single and multi-family housing starts that is captured in the CBOC method."

27.1 Explain how the CBOC and LHA HHF forecasts address single and multi-family housing starts and why their approaches are different.

27.1.1. Explain how these different approaches affect the residential customer forecasts.

Response:

Please refer to the response to BCUC IR2 45.1.

27.2 Is FEI of the view that the CBOC forecast is superior, based on the decision to true-up the LHA HHF forecast to the CBOC forecast? If not, provide additional rationale for the improvement to the forecast that is achieved by trueing up to the CBOC forecast.

Response:

Please refer to the response to BCUC IR2 45.1.

"Consistency in forecast methods is important to ensure efficiency and transparency in the development of the forecast and reduce the potential for unreasonable or conflicting results."

27.3 What conflicting results could arise if the forecasts are not trued up?

Response:

FEI prepares a short-term customer forecast for rate-setting purposes using only the CBOC forecast because municipal disaggregation is not required in the short-term forecast. The short-term forecast uses the single and multi-family splits from the CBOC data and is calculated at the regional level. The long-term forecast for system planning purposes requires municipal granularity and is developed using the method described in the Updated Application.

If the long-term forecast was developed only with HHF data two things would happen:

- The forecast would not have the benefit of the single family dwelling and multi family dwelling trends contained in the CBOC forecast; and
- Once the municipal forecasts were rolled up to the LHAs, and then the LHAs were rolled up to the region, is it unlikely the regional forecast would match the short-term forecast. If not reconciled ("trued up") to the short term, then it is conceivable that FEI could publish two different forecasts for a particular region and year. This is what FEI referred to as "conflicting results".

27.4 Explain the impact that eliminating the true-up on the demand forecast would have on the year that ITS capacity becomes insufficient (with implementation of short term mitigation measures). Does elimination of the true-up affect the year (2029) when additional compression in the East Kootenay region is expected to be required?

27.4.1. Graphically show FEI's forecasted ITS peak demand along with a forecast of ITS peak demand that does not true up to the CBOC forecast.

Response:

Please refer to the response to BCUC IR2 45.3.

28. Reference: Exhibit B-2, FEI Response to BCUC IR1, IR 7.1

"The system capacity is therefore designed to support the maximum hourly load and industrial customer load is assessed to determine their maximum hourly loads. These loads are applied to the distribution system models and roll up into the Transmission system models. The metered data for industrial customers does not have a high degree of consistency as customers can have daily periods of extended high flow, daily periods of extend low flow, or daily periods of intermittent high flow and low flow. Due to the inconsistent nature of industrial customers' daily demand, FEI models the capacity of the ITS assuming that the industrial customers are capable of sustaining their highest observed flow rate (as used in the peak hour distribution model) throughout the daily period. This also means FEI assumes that the periods of low consumption that an industrial customer might have on a typical day, that would contribute to rebuilding line pack in the system, will therefore not occur on a peak day."

28.1 Explain why the lack of line pack in the distribution system (which may justify using the peak hourly demand in capacity modeling of the distribution system) justifies the use of industrial customer peak hourly demand in each hour of the day when modeling the capacity of the transmission system.

<u>Response:</u>

Industrial demand can be sustained at high rates for daily periods, and can also occur at any time during the day. FEI also has no ability or physical means to directly control or curtail firm industrial demand. Therefore, FEI assumes that, on a peak day, industrial customer demand is sustained at the customer's highest rates throughout the day.

FEI was not implying that the lack of line pack in the distribution system is a justification for assuming industrial demand at sustained peak hour levels on the transmission system. Rather, in the response to BCUC IR1 7.1 cited above, FEI was describing that the daily demand in the transmission model happens to be "as used in the peak hour distribution model" (i.e. FEI's assumption is that the daily industrial demand is equivalent to 24 times the maximum hourly industrial demand).

28.1.1. Provide the proportions of total industrial customers in the areas served by the ITS that are connected to i) the distribution system, ii) the intermediate pressure system, and iii) the transmission system.

Response:

The following table provides the proportion of industrial customer accounts and industrial peak demand currently served by FEI's Interior transmission pressure (TP), intermediate pressure (IP), and distribution pressure (DP) systems.

Location and Demand of Industrial Customers Within the ITS		
System Pressure Designation	Number of Industrial Accounts	Peak Demand of Industrial Accounts
TP	2%	17%
IP	1%	5%
DP	97%	78%

28.1.2. Provide the proportions of total industrial customers in the areas served by the ITS that are connected to i) the distribution system, ii) the intermediate pressure system, and iii) the transmission system, but weighted by their peak demand.

Response:

Please refer to the response to RCIA IR2 28.1.1.

The data in the response to BCUC IR1 7.2.2 show that the load factor for the 2018 flows is approximately 88%. Likewise, the load factors for 2019 and 2020 are approximately 91% and 94% (subject to the inaccuracies of reading off the graph).

28.2 Explain why FEI does not apply a load factor to the peak hourly demand for industrial customers in the calculation of the peak day loads, as it appears these data are readily available.

Response:

RCIA's own calculations in the preamble show a six percent variation in the calculated load factor over the three coldest days in each of the most recent winters, with the highest load factor being approximately 94 percent. Further, the industrial load on the warmest day of the three load profiles was higher than colder days in following winters. These results show that there is enough variability in the data and a lack of temperature correlation such that arbitrarily adjusting industrial peak demands downward by applying an assumed load factor could risk underrepresenting the possible industrial load on a peak day. There could be significant consequences for all customers in the Okanagan region should this arbitrary load factor under-predict industrial demand on a peak day when determining the need for capacity upgrades.

29. Reference: Exhibit B-6, FEI Response to RCIA IR1, IR 3.1

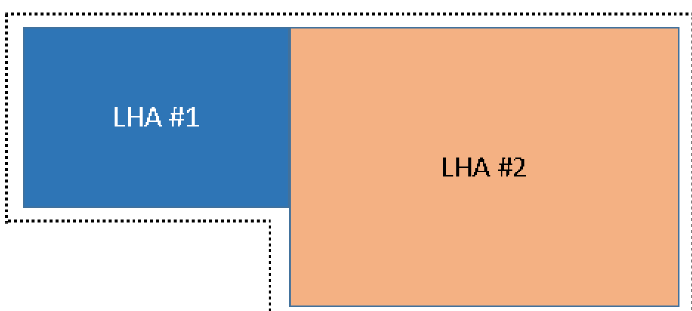
"Because many underlying drivers affect the level of FEI net customer additions in a given year, FEI is unable to confirm the extent or impact from any one of these intrinsic drivers (such as the proportion of households taking gas service) on an individual basis on the residential customer forecast."

29.1 RCIG IR1 3.1 did not ask FEI to confirm the extent or impact of any drivers that affect the proportion of residential customers that take gas service. RCIG IR1 3.1 requested FEI to confirm the mathematical observation that applying the LHA growth rate, which is based on overall household formations (i.e. all residential households), to its existing number of residential gas accounts (i.e. a subset of all residential households) results in the same proportion of residential gas accounts to residential households, which in turn means that the proportion of new residential households taking gas service is the same as the existing proportion of gas accounts to total residential households. Does FEI agree that this is implicit in its methodology?

Response:

Not confirmed. The proposition stated in the question only describes part of the residential forecast method. The following example illustrates why the mathematical observation described in the question cannot be confirmed once the full method, including the CBOC forecast data, is considered.

First, assume a hypothetical region with two local health areas.



Next, assume the following characteristics for LHA #1. The calculations are described in the table.

	LHA #1	
1	Year 1 Households	1,000.0
2	Year 1 Gas customers	800.0
3	HHF growth rate	1.20%
4	Proportion of households that are gas customers	80.0%
5	Year 2 Households	1,012.0
6	Year 2 Gas Customers	809.6
7	Proportion of households that are gas customers in Year 2	80.0%
8	New households	12.0
9	New gas customers	9.6
10	Proportion of new households that are new gas customers	80.0%

Row(s)	Discussion
1-3	For the purposes of this example, assume there are 1,000 existing households and 800 existing gas customers in a local health area. Assume that in the first year of the forecast the BC Stats growth rate for household formations in the LHA is 1.2%. Note: the data used here is for demonstration purposes only and is not intended to represent an actual LHA or FEI data set.
4	The actual proportion of existing customers to existing households is 80%.
5-6	In year 2, the growth rate from row 3 (1.2%) is applied to the existing households (1000) and the existing gas customers (800) to arrive at the year 2 totals of 1,012 and 809.6 respectively.
7	In this forecast, the proportion of Year 2 gas customers to households remains at 80% because both households and gas customers were grown by the same growth rate.
8-9	The new households and new gas customers are simply the additions. The additions are calculated by subtracting the Year 1 totals from the Year 2 totals. The LHA added 12 households and 9.6 gas customers.
10	The ratio of new gas customers to new households is 9.6/12 or 80%.

FEI notes that the ratio shown on row 10 does match the ratio on row four and if this was the extent of the method then the mathematical proposition in the question would be confirmed. However, the forecast of new gas customers shown on row nine has not been trued up to the CBOC forecast and there are additional steps that must be considered.

Assume the following characteristics for LHA #2. Note that the HHF growth rate on row 13 for this LHA is different from the growth rate for LHA #1 above (1 percent in this instance versus 1.2 percent above).

LHA #2		
11	Year 1 Households	2,000.0
12	Year 1 Gas customers	1,800.0
13	HHF growth rate	1.00%
14	Proportion of households that are gas customers	90.0%
15	Year 2 Households	2,020.0
16	Year 2 Gas Customers	1,818.0
17	Proportion of households that are gas customers in Year 2	90.0%
18	New households	20.0
19	New gas customers	18.0
20	Proportion of new households that are new gas customers	90.0%

The calculations for LHA #2 are the same as those described for LHA #1 in the table above. The final step is to introduce the regional CBOC forecast and to “true up” the forecast, as follows. Assume the following regional characteristics:

21	Simplified CBOC Regional Growth Rate	0.50%
22	Total regional gas customers	2,600
23	Year 1 new gas customers	13.0
24	Regional HHF New Gas Customers	27.6
25	True Up Factor	47%
26	Final LHA #1 new gas customers	4.5
27	Final LHA #2 new gas customers	8.5
28	LHA #1 proportion of new gas customers to new household formations	38%
29	LHA #2 proportion of new gas customers to new household formations	42%

Row(s)	Discussion
21	Assume the CBOC housing starts growth rate for the region is different from the LHA growth rates at 0.5%. As a simplification, this example does not use the single family dwelling/multi-family dwelling feature of the CBOC forecast. The mathematical proposition in the question can be demonstrated without the dwelling type split but FEI notes the dwelling type is an important feature of the CBOC growth rate forecast and is used by FEI for developing forecasts.
22	The CBOC growth rate is applied to the regional gas customer total (the sum of rows 2 and 12 i.e., 800 + 1800).
23	The CBOC regional forecast of new gas customers is row 21 multiplied by row 22, or 13 customers.
24	The forecast regional total of new gas customers from the HHF method is the sum of rows 9 and 19, and is greater than the regional sum calculated by the CBOC method.
25	The HHF forecast has the correct proportion, but not the correct regional total and must now be “trued up” against the CBOC result. The true-up factor is simply the ratio of the CBOC forecasted regional additions to the HHF forecast and in this example is 47%. The HHF forecasts all need to be brought down by 47% such that their sum matches the CBOC forecast of 13 customers.
26-27	The HHF new gas customer forecasts have been trued up to the CBOC forecast.
28	Finally, the trued up new gas customer forecast for LHA #1 can be compared to the HHF forecast of new households from row 8. The ratio is now 38% and does not match the original proportion of 80% for LHA #1.
29	The trued up new gas customer forecast for LHA #2 can be compared to the HHF forecast of new households from row 18. The ratio is now 42% and does not match the original proportion of 90% for LHA #2.

As shown in rows 28 and 29 of the preceding table the proportion of new residential households taking gas service is not the same as the existing proportion of gas accounts to residential households. In this instance, the mathematical proposition in the question is not confirmed. FEI notes that if the percentage growth rates on rows three, 13 and 21 all matched, then the mathematical proposition would be confirmed, however in general the various growth rates are never consistent between the LHAs or the CBOC.

“FEI does not determine the proportion of new households that take gas service for the purposes of the residential customer forecast. Rather, FEI applies the relevant LHA growth rates to the customer counts in each municipality to develop a 20-year customer forecast for each municipality as described in Section 3.3.1.2 of the Updated Application.”

29.2 If FEI has data on the proportions of new households who elect gas service in recent years, please provide.

Response:

Please refer to the response to BCUC IR2 44.1.

29.3 If FEI has data on the proportions of the total number of households who elect gas service (for example by comparing the number of residential gas accounts with the number of residential electricity accounts), please provide.

Response:

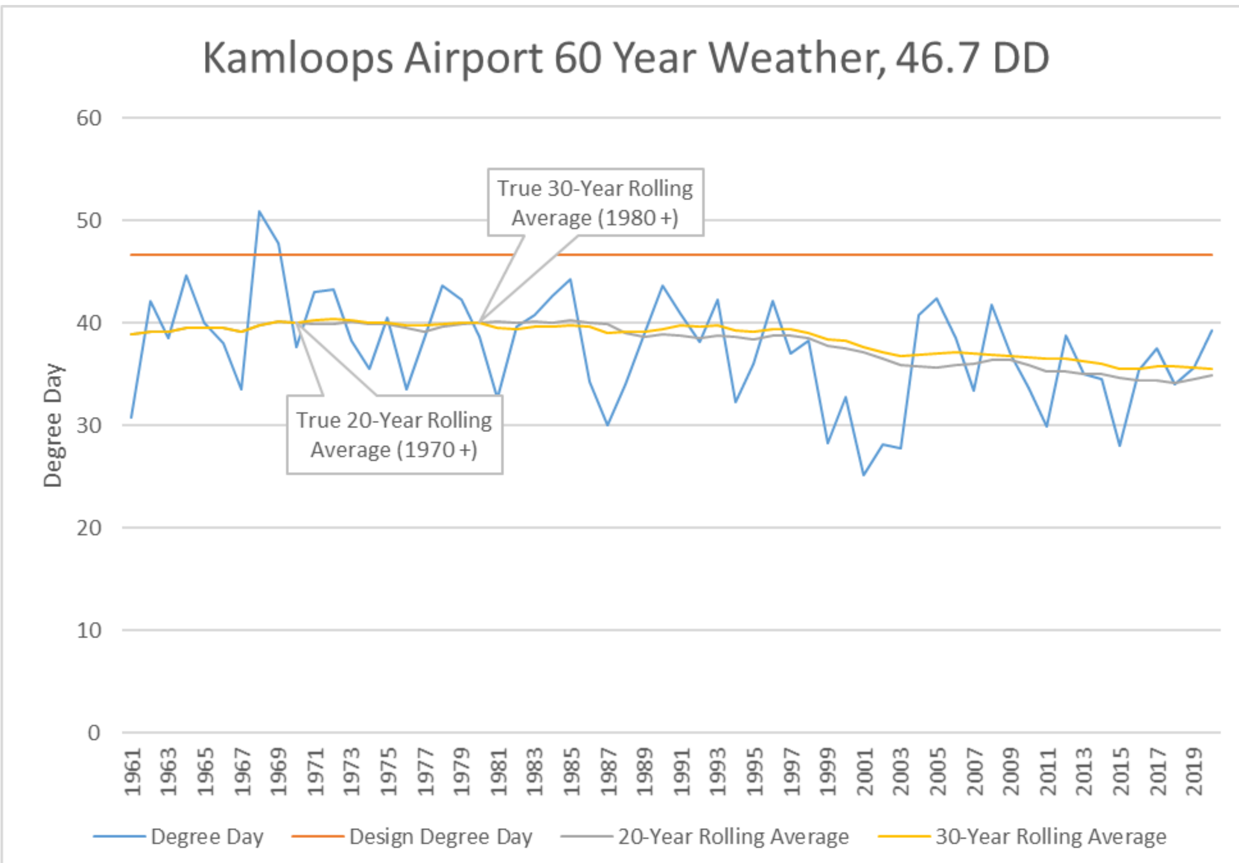
Please refer to the response to BCUC IR2 44.1.

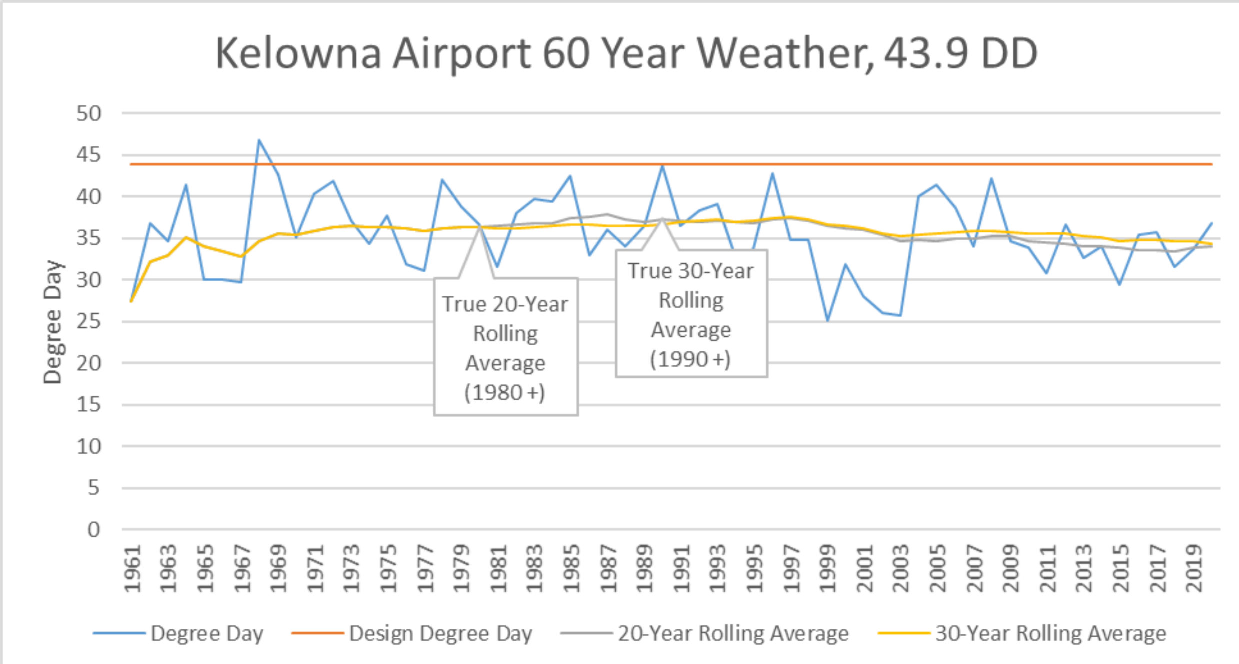
30. Reference: Exhibit B-2, FEI Response to BCUC IR1, IR 8.3

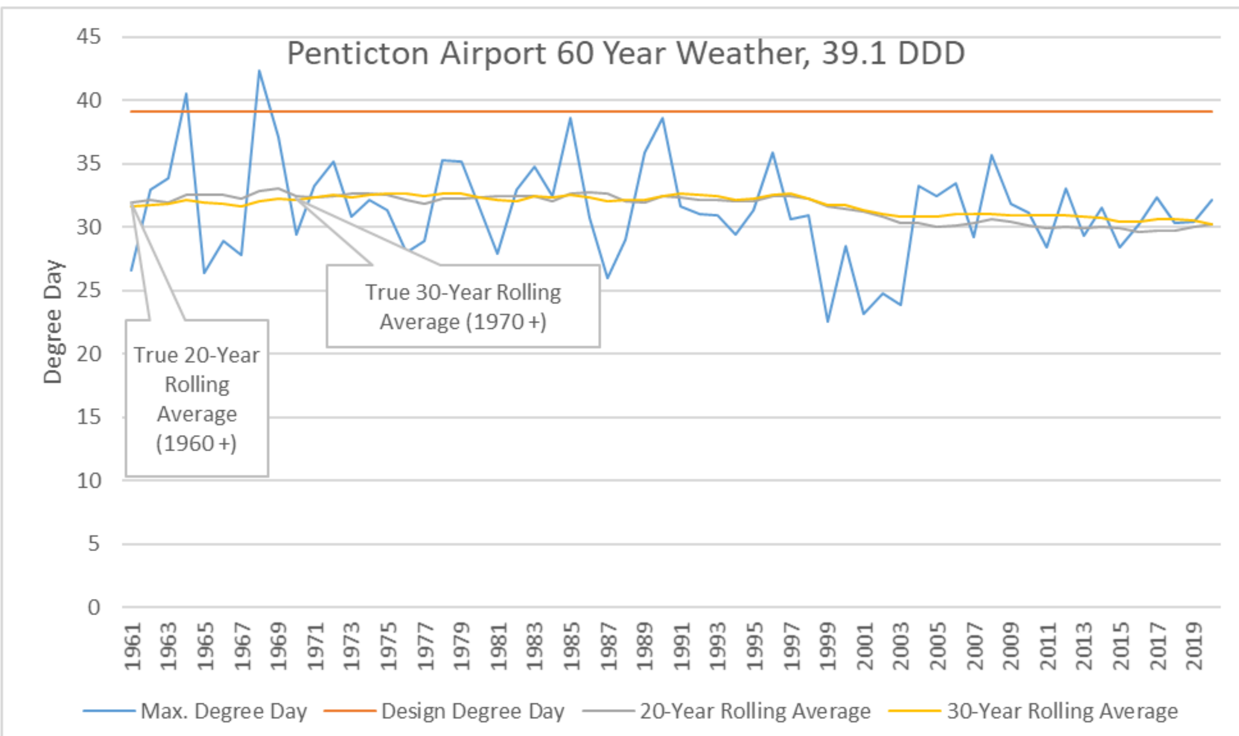
30.1 Please re-file the degree day graphs showing only the highest degree day each year. Overlay 20- and 30-year moving averages on the resulting data sets.

<u>Response:</u>

FEI provides graphs below to show the requested information. By definition, calculating a rolling average requires sufficient historical data. For example, a 20-year rolling average only becomes a true 20-year average when 20 years of data are available; similarly 30-year rolling averages only become valid when 30 years of data are available. This varies for each weather zone based on the amount of reliable historical data available. The point at which each 20- and 30-year rolling average becomes a true 20- or 30-year average is indicated on each graph.







30.1.1. Provide FEI's comments on any observed trends in the above graph.

Response:

In all weather zones, the rolling averages indicate a slight warming trend over the 60 year period. Each weather zone experienced a five year period between 1999 and 2003 where a lack of extreme temperature occurrences persisted. That five year period has a more noticeable warming effect on the rolling averages than any other period. In the most recent 15 year history, from 2004 onward, warming of the rolling averages appears to slow, but is influenced by that relatively warm period. In the period just prior to 1999, between 1980 and 1998, the rolling averages both warmed about 1°C in the Thompson Region (Kamloops), cooled about 0.9°C in the North and Central Okanagan (Kelowna) and remained reasonably constant warming very slightly by 0.2°C in the South Okanagan (Penticton).

31. Reference: Exhibit B-2, FEI Response to BCUC IR1, IRs 1.7, 6, 8.3; Exhibit B-6 FEI Response to RCIA IR1, IR 3.1; Exhibit B-1-2 Figure 4-1 p.37

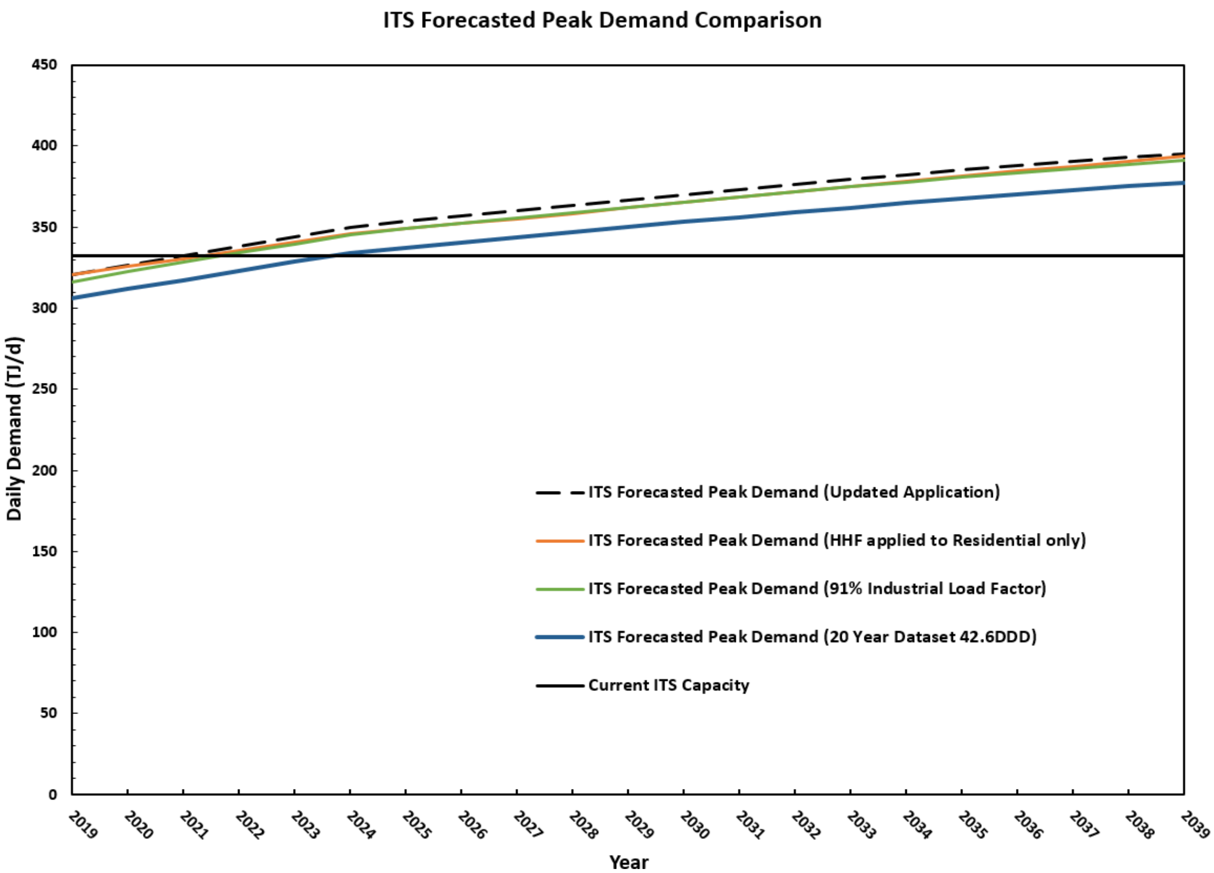
A number of assumptions and methodology decisions that support the peak demand forecast are conservative in that they result in a higher peak day forecast.

31.1 Recalculate the forecasted ITS peak demand with the following adjustments and graphically show the peak demand forecast along with ITS capacity (similar to Figure 4-1). Show the effect of each adjustment separately.

1. Do not true-up the residential customer forecast with the CBOC forecast data and instead use the LHA forecast of housing starts.
2. Apply a load factor, such as an average of the past three years, to the industrial peak hourly demand when calculating the peak daily demand.
3. Use a more recent data set of 30 years for the design degree day calculations.

Response:

The figure below presents the peak demand forecasts adjusted as requested. In BCUC IR2 43.3 FEI was asked to calculate the peak demand using a dataset of 40 and 20 years. In this response, FEI has presented the lowest forecast from the 20 year dataset (the lowest forecast) rather than generate another forecast using a 30 year dataset as it would be very similar to the forecasts using the 20 and 40 year datasets. FEI believes its established forecast method is an appropriate and prudent approach to ensuring reliable service to FEI's customers under peak demand conditions.



31.2 Explain how the above adjustments affect the timing of the need for the Okanagan Capacity Upgrade.

Response:

None of the variations in the forecasts described in the response to RCIA IR2 31.1 avoid the need for short-term mitigation in the winters prior to 2023/2024 in order to meet peak demand requirements in the Okanagan region. Please also refer to the responses to BCUC IR2 43.3 and 45.3 for additional discussion of the Project timing resulting from the adjusted forecasts.

B. Short-Term Mitigation Measures

32. Reference: Exhibit B-6, FEI Response to RCIA IR1, IR 6; Exhibit B-2, FEI Response to BCUC IR1, IR 2

"The minimum contractual delivery pressure at the East Kootenay Exchange (Yahk) by TC Energy is 5512 kPag (800 psig)."

"FEI has ongoing engagements with TC Energy regarding contractual delivery pressures and will continue to do so. However, changes in the Yahk delivery pressure would only impact the timing and sizing of a future compression expansion at FEI's Kitchener Compressor station and would not address the capacity constraint driver for the OCU Project."

32.1 Explain why it is acceptable that TC Energy delivers to the East Kootenay Exchange at 650 psig which is below the minimum contractual pressure.

Response:

FEI has engaged with TC Energy to reaffirm that the contract delivery will be met at the East Kootenay Exchange when required going forward. It was acceptable in the past because using 650 psig as an expected low value at Yahk has not resulted in any short-term capacity deficits in the ITS.

32.2 How would TC Energy delivering at the minimum contractual pressure of 800 psig affect the timing of the compression upgrade currently expected on FEI's ITS in 2029?

Response:

FEI clarifies that it inadvertently misstated the minimum contractual delivery pressure from TC Energy at Yakh. The actual figure is 750 psig, not 800 psig. This correction would not change the previous responses to RCIA IR1 6.7 and 6.8 other than the revised pressure.

TC Energy delivering at the minimum contractual pressure of 750 psig to Yahk would defer the compression upgrade requirements beyond the end of the forecast period.

C. Description and Evaluation of Alternatives

33. Reference: Exhibit B-6, FEI Response to RCIA IR1, IRs 8.3, 14.1

"FEI is unable to speculate about the location or extent of any further changes to class location that may occur during the forecast period."

33.1 Please discuss the differences between Alternatives 1, 2, and 3 in how future (and more restrictive) class location changes in the area between Penticton and Vernon could affect the ability of Alternatives 1, 2, and 3 to meet the project objective of providing sufficient transmission system capacity for the twenty-year planning period. That is, which alternative is likely to be the least affected by future class location changes?

Response:

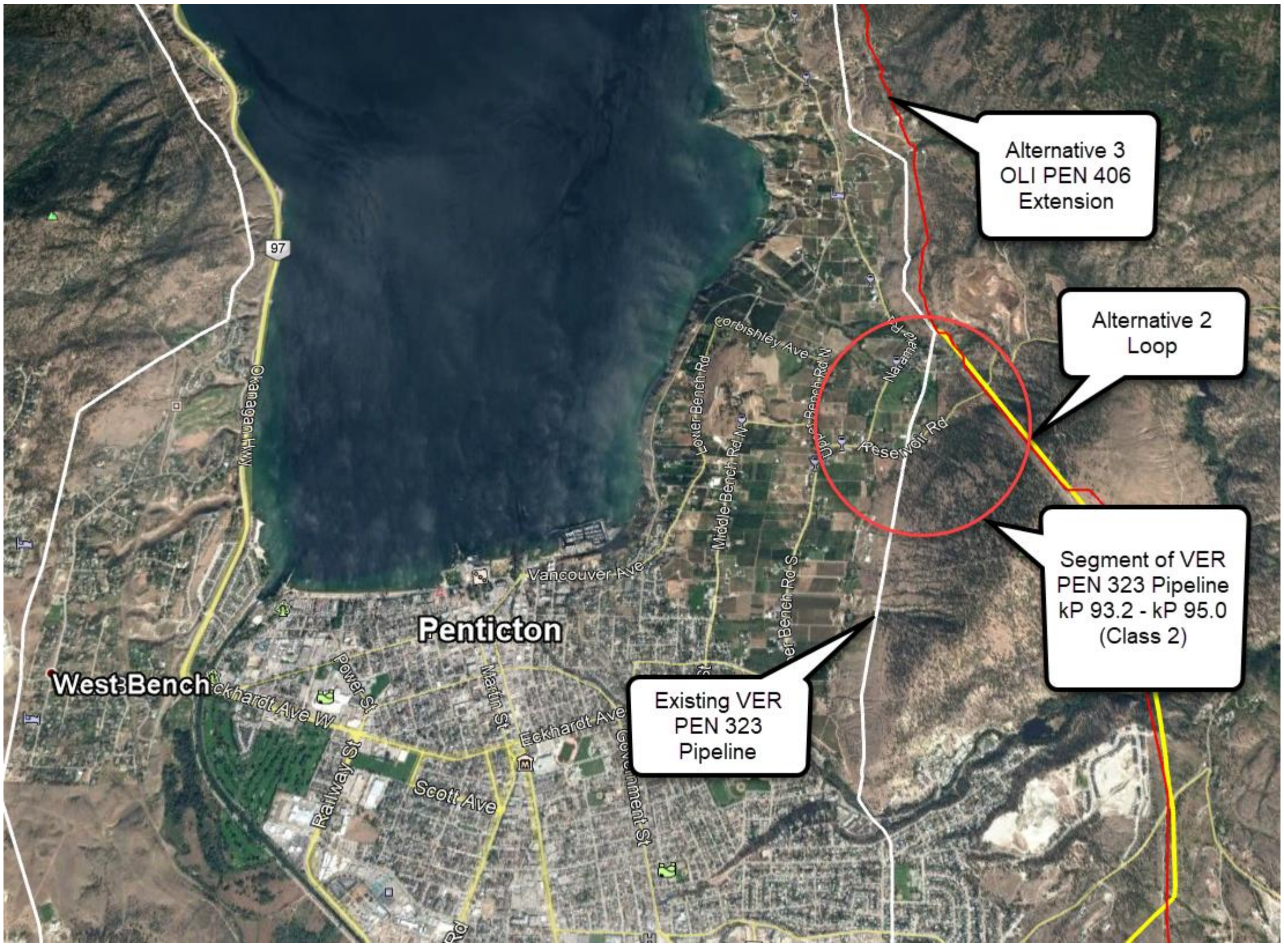
Alternative 3 (the proposed OLI PEN 406 Extension) is the alternative least susceptible to changes in class location leading to future pressure derating resulting in a corresponding ITS capacity reduction. Though the entirety of Alternative 3 currently runs through Class 1 and 2 locations, it will be constructed and pressure tested such that it is acceptable for operation in a Class 3 location. This pipeline will therefore not be susceptible to pressure reduction requirements should the surrounding area become more densely populated. Additionally, Alternative 3 runs through mountainous, unpopulated terrain which is less likely to see increasing density than the area surrounding the VER PEN 323 pipeline.

The short loop of new pipeline north of Penticton, which would be included in the scope of Alternative 2, would be designed to meet Class 3 location criteria. This alternative would be slightly preferable to Alternative 1 in this regard, as the Class 3 design of the new pipeline would allow for increasing density north of Penticton without requiring a future pressure derating. Alternative 1 would be the least preferable option from a class location standpoint, as it leaves the entire transmission corridor between Penticton and Kelowna susceptible to future class location changes.

33.2 Confirm whether a class location change from class 2 to class 3 in the area of kilometer post 93.2 to kp 95 would cause FEI to derate the MOP of the VER PEN 323 line from its current MOP of 5171 kPa.

Response:

No derating would be required. In the case that this segment changes to a Class 3 location in the future, the current MOP would be sufficient. An image of this region is provided below.



33.2.1 If Alternative 1 was implemented and the VER PEN 323 MOP was re-established to 6619 kPa, confirm whether a class location change from 2 to 3 in this segment (kp 93.2 to 95) would cause the MOP to be derated. To what MOP would the pipeline be derated? How would this affect the ITS capacity?

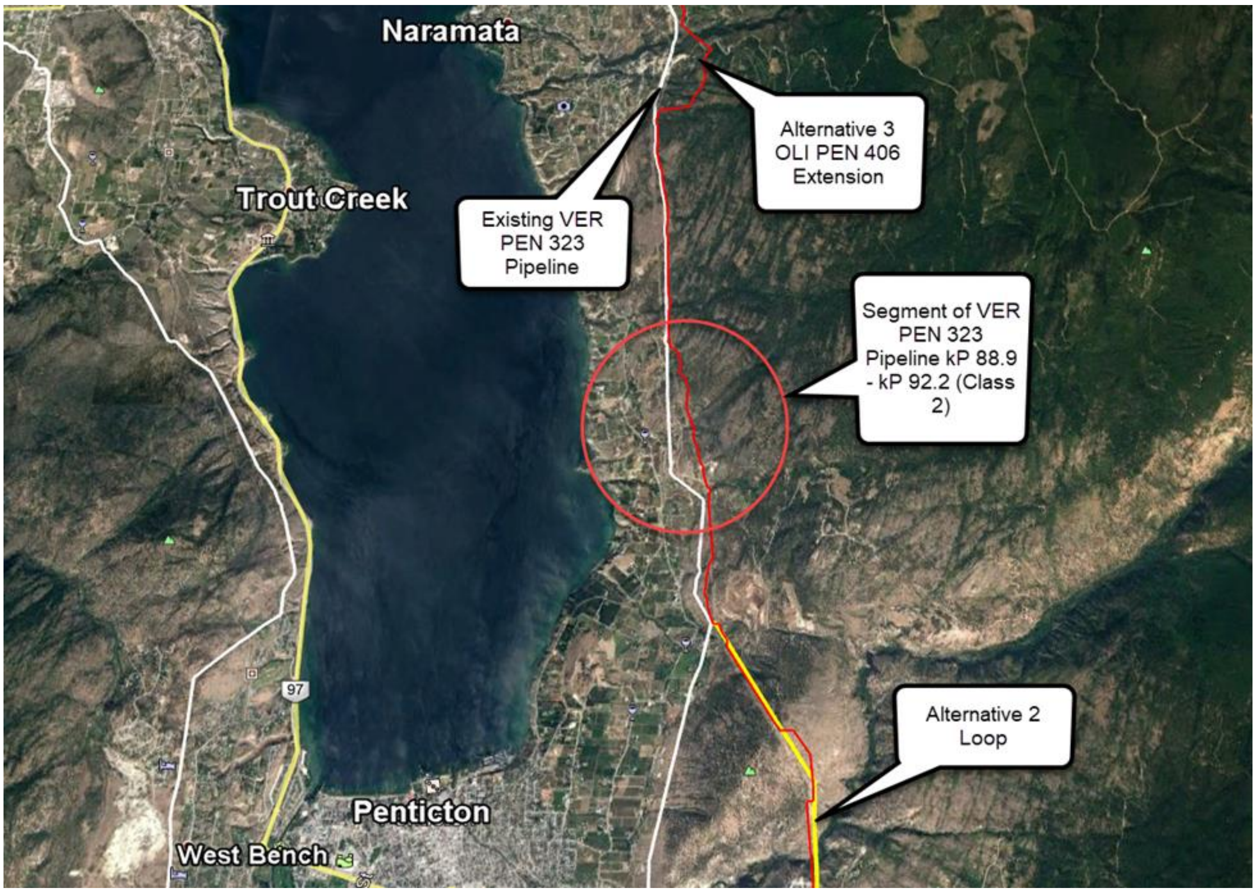
Response:

As part of Alternative 1, this segment would be replaced with thicker, higher-grade pipe, and tested to Class 3 requirements. Based on this, an MOP of 6619kPa for the segment in question would be acceptable for operation in a Class 3 location.

33.3 Confirm whether a class location change from class 2 to class 3 in the area of kilometer post 88.9 to kp 92.2 would cause FEI to derate the MOP of the VER PEN 323 line.

Response:

No derating would be required. In the case that this segment changes to a Class 3 location in the future, the current MOP would be sufficient. An image of the pipe segment in question is provided below.



33.3.1 If Alternative 1 or 2 were implemented and the VER PEN 323 MOP was re-established to 6619 kPa, confirm whether a class location change from 2 to 3 in this segment would cause the MOP to be derated. To what MOP would the pipeline be derated? How would this affect the ITS capacity?

Response:

An MOP of 6619 kPa would not be acceptable for the VER PEN 323 segment in question if the class location changed from 2 to 3. From approximately kP 91.3 to 92.2 (the southern end of the segment in question) the pipeline would need to be replaced with thicker wall, higher grade pipe as part of either Alternatives 1 or 2 and would then be pressure tested for operation in a Class 3 location. Should a class location change occur in this portion of the pipeline, no further derating would be required.

The remainder (approximately 2.4 km from kP 88.9 to 91.3) would not be replaced as part of Alternatives 1 or 2 and instead would be pressure tested to certify it at the 6619 kPa operating pressure for a Class 2 location. This segment of pipe would not meet Class 3 location criteria at an MOP of 6619kPa. Should the class location of this section change from Class 2 to 3 following implementation of Alternative 1 or 2, if the pipeline was not subsequently replaced with thicker wall, higher grade pipeline, this segment would need to be derated to 5174 kPa. This derating would not be acceptable as it would trigger capacity shortfall issues similar to those currently driving the need for the OCU Project. As such, a pipeline replacement to maintain the higher MOP and therefore ITS capacity would be required.

34. Reference: Exhibit B-6, FEI Response to RCIA IR1, IR 15; Exhibit B-1-2 Section 4.6.2.2, 4.6.3.1 pp.51, 55

"'Do the cost estimates for Alternatives 1 and 2 include the cost to repair any damage from failed hydrostatic testing as well as the cost of subsequent tests?'

Yes, Alternatives 1 and 2 include an allowance for the cost of pipeline repairs and subsequent tests from failed hydrostatic testing."

Table 4-8 of the Application gives the Capital Cost As-Spent for Alternative 1 as $220,215 and for Alternative 2 as $232,927.

"Due to limitations on allowable elevation difference on a test section, thirty-three requalification tests would be required in addition to six tests for the replacement segments."

34.1 Provide the as-spent capital costs for Alternatives 1 and 2 assuming there are no failed hydrotests and therefore no subsequent repairs.

<u>Response:</u>

The as-spent capital cost, assuming there are no failed hydrostatic tests and subsequent repairs, for Alternative 1 is $213.7 million and for Alternative 2 is $227.5 million.

34.2 Are 39 hydrotests tests required for Alternative 1, Alternative 2, or both? If for Alternative 1, how many tests are required for Alternative 2?

<u>Response:</u>

The number of test segments required to recertify the existing pipe is driven by the elevation difference along the length of a segment, such that the maximum test pressure within each segment is limited to a pressure that does not produce hoop stresses in excess of 95 percent of SMYS in the pipe.

- A total of 33 requalification tests would be required to recertify the existing pipeline to operate at higher MOP under Alternative 1.
- A total of 32 requalification tests would be required to recertify the existing pipeline to operate at higher MOP under Alternative 2.

Please note that new pipe is also being added in both alternatives to replace some existing pipe. This new pipe (the six replacement segment tests mentioned in the referenced text) will also require pressure testing as part of construction certification. The number of test segments required to pressure test the new pipe are not included in the numbers provided above. In other words, the counts above refer to requalification tests of existing pipe only. The numbers given above also have no contingency allowances to cover any failures that occur during hydrotesting the existing pipe and which may require FEI to further segment and retest the pipeline.

34.3 How many of re-tests are included in the capital costs for each alternative?

Response:

FEI assumed a failure rate of approximately 20 percent, or eight failed hydrotests associated with Alternatives 1 and 2. The cost to locate each leak and repair the damage was estimated at $500 thousand, for a total estimated repair cost of $4 million for each of Alternatives 1 and 2.

34.4 How would FEI repair a failed pipeline segment that is under Ellis Creek, Penticton Creek, Naramata Creek, or any environmentally sensitive area?

Response:

The repair activity will vary depending on a number of variables including:

- failure location;
- terrain;
- accessibility;
- species at risk or other environmental considerations;
- natural hazards and waterways; and
- pipe condition upstream and downstream of the failed segment.

FEI's preferred repair process would be to expose the pipeline in the failed area, perform additional visual investigations, cut out the segment and replace with new pipe. For areas where it would be challenging to perform these activities, other replacement methods would be considered, including installing new pipe using trenchless options.

34.4.1 What are the implications for obtaining any required permits on the timeline for repair of failed pipe segments in these challenging areas?

Response:

The BC Oil and Gas Commission (BCOGC) permitting for pipeline repair or replacement within a stream channel or other environmentally sensitive area typically takes approximately three months to compile and submit the application, followed by up to three months for application review by the BCOGC before the permit approval. Once approved, FEI is required to provide all Indigenous groups in the region 10 business days advance notification of construction starting as per typical permit conditions. The three months of application compilation may become extended when pipeline engineering and/or in-stream works hydrogeological revetment engineering designs are required. The in-stream works are typically required by permit conditions to be completed during the fisheries least-risk window during the summer. The in-stream works may not be logistically possible during periods of peak stream flow.

Other factors affecting the review and approval timeline include the location and footprint of the work. Other permitting approvals from separate regulatory agencies may be required by the BCOGC prior to approving the BCOGC permit application, such as:

- Agricultural Land Commission approval of portions of the project footprint within the agricultural land reserve;
- DFO or Environment Canada approvals where impacts to fish and fish habitat or endangered and/or threatened species and associated critical habitat exists within the project footprint;
- Archaeological site alteration permit approval if a known archaeology resource site is within the project footprint or an archaeological chance-find occurs in the project footprint; and
- Indigenous groups’ consultation process may be extended by the BCOGC when questions, comments and concerns arise from the consultation process resulting in application revisions which in turn may reset the consultation timeline.

Each of the above steps typically takes two to four months to obtain.

D. Project Cost Estimate

35. Reference: Exhibit B-6, FEI Response to RCIA IR1, IR 20; Exhibit B-2-1 pp.24, 69; Exhibit B-2, FEI Response to BCUC IR1, IR 30

"The Ellis Creek Pressure Control Station connects and provides pressure control (regulation) and overpressure protection from the OLI PEN 406 pipeline operating at a maximum operating pressure (MOP) of 7,826 kPa to the VER PEN 323 pipeline operating at an MOP of 5,171 kPa. It also provides seasonal flow control via the SN10-3 block valve into the VER PEN 323 pipeline, allowing control of gas flows either to the north or south."

"FEI did not consider relocating and repurposing the station equipment at the Ellis Creek Pressure Control Station for two reasons. First, FEI must maintain full functionality of the Ellis Creek Pressure Control Station until the new OLI PEN 406 extension is completely commissioned. The commissioning process may take several months due to the potential for odor fade4 in newly constructed steel pipelines. It would be impractical to attempt to repurpose the equipment when both the Ellis Creek Pressure Control Station and newly constructed Chute Lake Pressure Control Station are required to be operational simultaneously."

"The South tie-in to the new pipeline will be an underground butt-weld into the existing OLI PEN 406 pipeline."

35.1 Provide additional explanation for why the Ellis Creek station must remain in operation during the start-up and commissioning of the OLI PEN 406 extension (Alternative 3).

Response:

To provide more schedule flexibility during construction and commissioning, FEI has chosen to install the bypass system to allow both the Ellis Creek Pressure Control Station and the newly constructed Chute Lake Pressure Control Station to operate simultaneously.

Completion of the construction, testing, and commissioning of the OLI PEN 406 extension and Chute Lake Pressure Control Station is currently scheduled for September and October of 2023. FEI has determined that the window during which system elements can be removed from service for work on the system at this time of the year is limited to a 10 Degree Day or warmer. Only during this window could the tie-in procedure be completed without a bypass system and maintaining flow through the Ellis Creek Pressure Control Station.

35.2 How will the Ellis Creek and Chute Lake stations be in operation simultaneously if gas can no longer flow on the 1.2 km section of line following the tie-in?

Response:

As explained in the response to RCIA IR2 35.1, during the commissioning process, both the Ellis Creek Pressure Control Station and the newly constructed Chute Lake Pressure Control Station will be operational simultaneously. This will be accomplished by installing a bypass system around the south tie-in location to maintain flow through the 1.2 km section of line feeding the Ellis Creek Pressure Control Station to be deactivated at the end of the OCU Project. The bypass system will be removed during the deactivation procedure.

35.3 Explain how FEI will operate the Ellis Creek and Chute Lake stations to mitigate odour fade in the newly constructed pipeline.

Response:

FEI plans to utilize a blending method to support the conditioning process of the newly constructed OLI PEN 406 Extension. This will consist of providing a smaller flow of gas where the odourant has been absorbed by the new steel and flowing through the Chute Lake Pressure Control Station into the VER PEN 323 where it will blend with odourized gas supplied to the VER PEN 323 either from the North (SN9-3) or the South (Ellis Creek Pressure Control Station). This procedure has been successfully implemented on FEI's recent pipeline projects. FEI has conducted an analysis to determine potential duration and demand impacts with this strategy. During higher demand months (typically October through March), supply from Ellis Creek Pressure Control Station is necessary to meet system demand while ensuring minimum odourization levels. FEI plans to install a temporary odourant injection system at the Chute Lake Pressure Control Station for the commissioning process to mitigate odour fade.

35.4 Confirm whether FEI has upgraded the Ellis Creek station pressure regulating equipment or any other substantial components since the station was constructed (presumably in 1994).

Response:

FEI has not completed any upgrades to the pressure regulating equipment since its construction and commissioning in 2001. FEI installed a remote terminal unit (RTU) and telemetry system for remote site monitoring and control in 2005, completed upgrades to the RTU in 2014, and upgraded the site fencing in 2017.

35.5 Confirm whether it will be possible to perform inline inspections of the 1.2 km deactivated portion of OLI PEN 406 if Alternative 3 is constructed.

Response:

FEI will not be able to perform conventional inline inspections (ILI) of the 1.2 km deactivated portion of the OLI PEN 406 if Alternative 3 is constructed as designed. FEI would need to install an ILI tool launcher near the south tie-in location or utilize non-conventional methods, such as robotic tools, to collect necessary data to perform an engineering assessment prior to reactivation.

"The gas supplies from the north and south converge at the lowest pressure point within this portion of the ITS, typically near the Polson Gate Station on the south side of Vernon."

"Should the BCUC approve the ITS TIMC project, and if cracking is found in the VER PEN 323 section which would require significant rehabilitation or replacement, FEI may choose to reactivate the 1,200 m section of the OLI PEN 406 to provide additional redundancy and resiliency to the Penticton and Summerland systems."

35.6 What are the prevailing directions of flows, by season, on the NPS 12 line between SN10-3 and the ITS interconnect on the west side of Penticton?

Response:

In the present ITS configuration, SN 10-3 is normally closed and provides an isolation between gas at 5171 kPag leaving the Ellis Creek Pressure Control Station flowing north on the VER PEN 323, and gas leaving the Oliver Y Control Station at 4826 kPag heading north on the PEN OLI 273 (to supply customers north of Oliver to Penticton Gate Station and along the Summerland Lateral on the west side of Penticton). In off-peak conditions when required for operational purposes, the pressure at the Ellis Creek Pressure Control Station can be reduced to 4826 kPag and SN 10-3 can be opened to allow gas from the VER PEN 323 to flow southwest to supply into the PEN OLI 273.

35.6.1. If prevailing flows are west to east, how will reactivation of the deactivated 1.2 km segment of OLI PEN 406 assist with the ITS Transmission Integrity Management Capabilities program?

Response:

FEI's ITS is interconnected such that there are a variety of possibilities of how gas can be directed around the system to support operational work. FEI is not reliant on maintaining prevailing flow in a particular direction in the pipelines in and around Penticton for much of the year. The reactivation of the deactivated line is not necessary to enable the ITS Transmission Integrity Management Capabilities program. However, FEI foresees opportunities such as described in the preamble above, where a reactivation of the interconnection may become a cost-effective solution to address future operational issues or pressure reductions resulting from integrity or other operational reasons.

35.7 Once the ITS Transmission Integrity Management Capabilities program is completed, will there be any future uses for the deactivated 1.2 km of the OLI PEN 406 line and the Ellis Creek station? If so, explain what these uses will be.

Response:

FEI has considered future scenarios in which these assets would be reactivated. Please refer to the responses to BCUC IR1 30.5 and BCUC IR2 56.3 and 56.3.1 for a discussion of these assets' potential benefit to the ITS TIMC Project. While there are no specific integrity requirements beyond the ITS TIMC identified at this time, FEI will continue to monitor the need for this deactivated pipeline and may propose abandonment at some future time if it is in the interests of FEI and its customers.

"The scope of work for abandonment would follow FEI abandonment specifications and is consistent with industry standard practice…Between the two isolated ends, FEI would excavate every 200 metres, segment the pipe, and install a cap on each side. Each segmented section would be grout filled to prevent pipe collapse (since cathodic protection would be discontinued it is expected that the pipe would corrode away over time)."

35.8 Identify the industry standards or guidelines (and provide excerpts) that state that cutting and capping of an abandoned pipeline is required every 200 metres.

Response:

CSA Z662:19 clause 10.16.2 provides the minimum requirements for buried pipelines abandoned in place, including physical separation from any in-service piping and capping, plugging or otherwise effectively sealing the abandoned line. The Canadian Energy Regulator (CER) published document "Pipeline Abandonment: A Discussion Paper on Technical and Environmental Issues", November 1996[1], where Section 3.9 provides recommended plug locations for abandoned lines to limit creation of water conduits.

In particular, Table 3-1 states:

Table 3-1 Recommended Plug Locations	
Terrain Feature	Plug Locations
waterbodies/watercourses	above top of bank
long inclines (>200m), river banks	at top and bottom of slope and at mid-slope for long inclines
flood plains	at boundaries
sensitive land uses (e.g. natural areas, parks)	at boundaries
near waterfalls, shallow aquifers, groundwater discharge and recharge zones, marshes, sloughs, peatlands, highwater table areas	at boundaries and should include an adequate buffer zone
cultural features (population centres)	at boundaries

Beyond the language above, neither the CSA Z662:19 standard, nor the CER guidelines, provide specific guidance for the segmentation of abandoned pipelines and instead leave this to the discretion of the pipeline operator. FEI's internal abandonment specifications require buried pipelines to be emptied, purged, isolated, and left in a safe condition so that there are no risks to the public or environment. This includes the segmentation of the abandoned buried pipeline every 200 metres. FEI would conduct a review to determine the suitability of the plug locations during detailed design based on site-specific characteristics if in the future FEI pursued abandonment for the section of the OLI PEN 406 in question.

35.9 Identify the industry standards or guidelines (and provide excerpts) that require grouting of the pipeline along its full abandoned length.

[1] https://www.cer-rec.gc.ca/en/applications-hearings/pipeline-abandonment/pipeline-abandonment-discussion-paper-technical-environmental-issues.html

Response:

The Canadian Energy Regulator (CER) document "Pipeline Abandonment: A Discussion Paper on Technical and Environmental Issues", November 1996[2], Section 3.3 discusses ground subsidence and recommended mitigation strategies. In particular, Section 3.3.5 states:

> "In areas where no settlement is allowed, either by regulation or agreement (such as at highway crossing sites, as further explained in Section 3.8), the option would exist to fill the pipeline with an approved solid material such as concrete or sand."

FEI abandonment specifications require buried pipelines to be emptied, purged, isolated, and left in a safe condition so that there are no risks to the public or environment. This includes grouting of large diameter (greater than 323 mm) pipelines in areas where ground subsidence would pose a safety hazard. The OLI PEN 406 segment is located in an industrial area, frequently impacted by heavy vehicular loads, such as dump trucks accessing the nearby gravel pit. As such, grout filling would be considered necessary and reasonable to ensure public safety in the area of this pipeline section.

35.9.1. Is grouting to prevent subsidence required along the full abandoned length or only where the pipeline crosses (or is co-located with) roads and railways?

Response:

Please refer to the response to RCIA IR2 35.9.

---

[2] https://www.cer-rec.gc.ca/en/applications-hearings/pipeline-abandonment/pipeline-abandonment-discussion-paper-technical-environmental-issues.html

36. Reference: Exhibit B-6, FEI Response to RCIA IR1, IR 22.1, 22.3

"The table below provides details on two gas pipeline CPCN projects FEI has undertaken within the past five years that are of a similar magnitude as the OCU Project and in excess of $50 million in estimated capital costs. Both of these projects are currently underway and, as such, final actual project costs are not yet available."

36.1 Does FEI have any recently completed pipeline projects for which it can show the budgeted contingency, management reserve, and escalation reserve in comparison with the final amounts expended? If so, provide the base costs, budgeted contingency, management reserve, escalation reserve, the final cost of the project, and the amounts allocated to the contingency and reserves for each completed project.

Response:

The most recent CPCN pipeline projects completed by FEI are the Huntingdon Bypass and the Muskwa River Crossing. These projects involved the installation of short pipeline segments (0.2 km of NPS 36 pipe and a 0.6 km NPS 6 HDD installation, respectively), and are not directly comparable to the OCU Project. The requested details for both projects are shown in the table below. Note that a management reserve was not identified for either project.

Particulars	Huntingdon Bypass $millions	Muskwa River Crossing $millions
Base Costs	6.668	5.307
Contingency	0.722	1.315
Escalation	0.800	0.107
AFUDC	0.434	0.311
Total Project Cost Estimate	8.624	7.040
Total Final Cost	7.004	5.111
BCUC Order	G-193-15, G-182-16	G-97-15

With respect to the Huntingdon Bypass project, the contingency and escalation were developed to meet the AACE Class 3 guidelines that have an associated range of +30 to -20 percent. In FEI's final project report to the BCUC for the project, there was no allocation of the final cost to contingency.

For the Muskwa River Crossing project, the contingency and escalation were developed to meet the AACE Class 3 guidelines that have an associated range of +30 to -20 percent. For this project, $10 thousand was the remaining contingency out of the final cost of $5.111 million. In the final report to the BCUC, the remaining contingency identified was to allow for minor site repairs.

36.2 Were any of these completed projects in excess of the amount budgeted in the CPCN Application? If so, did the BCUC approve the collection from ratepayers of the full additional amounts in excess of the CPCN approved budgets?

36.2.1. Provide a summary of or a reference to the BCUC decisions on the approval of these rate base additions.

Response:

The final cost for both projects was less than forecast in the CPCN application and no costs were disallowed for inclusion in Rate Base. The Huntingdon Bypass project was not referenced specifically in either of the BCUC Decisions on FEI's Annual Reviews for 2016 or 2017 Rates, but was included in the rate base upon which the approved rates were calculated. The Muskwa River Crossing project was mentioned in the BCUC Decision for the FEI Fort Nelson RRA for 2015 and 2016. The BCUC commented that the final cost of the project was lower than projected in the CPCN application.

36.3 Has the BCUC approved rate base additions for any projects which received a CPCN but denied the rate base additions for the costs which exceeded the costs budgeted in the CPCN application? If so, provide details.

Response:

FEI notes that in granting a CPCN for a project, the BCUC makes a determination of the public interest regarding the project, which is in part based on the cost estimate provided in the CPCN application. In recent years, the BCUC has directed periodic reporting on the progress of projects which includes updates to project expenditures, implementation schedules and, in some cases, a requirement to file a material change report if, for example, there is a material change in the project cost estimate. The following table lists the two CPCNs that were approved by the BCUC and which subsequently had some costs disallowed.

CPCN Project	Project Cost Estimate in CPCN Application ($ millions)	Final Cost ($ millions)	Disallowed Cost ($ millions)
Sooke Main Extension	4.262	4.970	0.079
Whistler Pipeline & Conversion	6.011	11.870	0.840

The Sooke Main Extension CPCN was approved in 2002. The amount of disallowed cost was determined in Order G-113-04 in the Annual Review for 2005 Rates for FEI's Vancouver Island service area (then Terasen Gas (Vancouver Island) Inc.). The Whistler Pipeline and Conversion CPCN was approved in 2006. The amount of disallowed cost was determined in Order G-138-10 in the 2010 and 2011 Revenue Requirements Application for FEI's Whistler service area (then Terasen Gas (Whistler) Inc.).

36.4 At what confidence levels did FEI fund (and receive CPCN approval for) the contingencies, management reserves, and escalation reserves shown in the response to RCIG IR1 22.1?

Response:

For the two projects shown in the response to RCIG IR1 22.1, the evidence submitted to the BCUC in the CPCN applications included contingency and management reserve funded at the confidence levels shown in the table below. The BCUC approved the CPCNs as being in the public interest based on a number of factors.

FEI provides a table below showing the confidence levels for contingency and management reserve for these two projects. Note that the LMIPSU Project did not include a management reserve. Further, escalation for both projects was considered as a percentage/dollar value and not derived using a probabilistic analysis.

Risk Funding Category	LMIPSU Project	IGU Project
Contingency	P50	P50
Management Reserve	Not funded	P70

37. Reference: Exhibit B-5, FEI Responses to CEC IR1, IR 37

"Market risk covers increased costs to the project stemming from a reduced level of competitiveness when trying to recruit a construction contractor specialized in building gas line projects through mountainous terrain with shallow bedrock."

37.1 What are FEI's assumptions about the amount of excavation (as a proportion of the pipeline route) that is expected to be through bedrock, requiring blasting or hydraulic hammer excavation?

Response:

As outlined in the Project Design Basis Memorandum, P-00760-PIP-DBM-0001, in Confidential Appendix A-1 of the Updated Application, the OCU Project route requires excavation through bedrock requiring substantial rock blasting for approximately 70 percent of the pipeline route or approximately 22 km.

37.2 If bedrock excavation is required for substantially all of the pipeline route, what is the additional cost that FEI expects to incur?

Response:

FEI does not anticipate additional costs to excavate bedrock beyond what is included in the Class 3 Project estimate, as the estimate was developed recognizing the varying geological properties and features along route. FEI identified the potential of increased blasting work in the Risk Register (Risk ID 200 included in Confidential Appendix C-1 of the Updated Application), with an expected value of $667 thousand included in the contingency calculation.