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

March 4, 2021

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599152

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On November 16, 2020, FEI filed the Application referenced above. In accordance with BCUC Order G-335-20 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page no.**

A. PROJECT NEED AND JUSTIFICATION

1.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2 (Updated Application), pp. 18, 28, 29

Impacts of COVID-19

On page 18 of the Updated Application, FortisBC Energy Inc. (FEI) states, "FEI's system capacity planning team refreshes its forecast annually, based on the most recently available customer addition and consumption data."

On page 28 of the Updated Application, FEI states:

> FEI's peak demand forecast was prepared in 2019, before the onset of the COVID-19 pandemic. As of the date of filing, there is insufficient data to quantify the COVID-19 impact, to forecast its future impacts on energy consumption or, more importantly for system planning, its impact on peak loads. FEI acknowledges that the immediate and near-term impacts of the pandemic may be significant for some types of customers and economic sectors. However, FEI presently has insufficient information to quantify these impacts.

On page 29 of the Updated Application, FEI states:

> In summary, given the lack of firm information on COVID-19 related impacts on the peak load in 2023/2024 and future years, the continuing potential for significant new loads in urban centres like Kelowna, the limitations of existing short-term mitigation measures, and the lead time required for a project of this nature, FEI concludes that it would not be prudent to delay the addition of ITS [Interior Transmission System] capacity and that the OCU [Okanagan Capacity Upgrade] Project should proceed as set out in this Application.

1.1 Please discuss when FEI expects its 2020 peak demand forecast will be available, and whether FEI expects to file an updated demand forecast as part of this proceeding.

<u>Response:</u>

FEI is not proposing to file an updated peak demand forecast as part of this proceeding. FEI is still developing, and has not yet completed, an updated peak demand forecast for the ITS, current as of 2020 and using the results of the 2020 account forecast. As such, FEI is unable to provide an updated 2020 peak demand forecast at this time.

Although FEI's 2020 customer account forecast is complete, the completion of the 2020 peak demand forecast and its impacts on the ITS lags the completion of the current account forecast by about 9-10 months as it relies on the development of the load in the models of the distribution system connected to the ITS that are built using the updated account forecast.

Notwithstanding this, preliminary results indicate that the updated peak demand forecast will not change the impending requirement for the OCU Project. The updated forecast will only provide FEI with a more current assessment of the extent of short-term mitigation measures that were described in the Updated Application and that will still be required from the winter of 2021-2022 until the Project is completed.

1.2 Please provide a detailed discussion of the work FEI is undertaking with respect to estimating the impact of the COVID-19 pandemic upon peak demand forecasting, including any timelines for such work.

Response:

FEI still has insufficient data to quantify any potential impact of the COVID-19 pandemic on peak demand forecasts. As discussed in Section 3.3.1.2 of Updated Application, FEI bases its customer forecast method on forecasts from the Conference Board of Canada (CBOC) and the BC Statistics 20-year household formation (HHF) forecast. FEI has not received updates to these forecasts since the beginning of the pandemic. FEI has also continued to attach customers in 2020 at rates comparable to 2019 which suggests that, so far, the pandemic has not materially affected current growth rates. FEI will review and incorporate updated forecasts from the CBOC and BC Statistics when they are received and apply these updates to the forecasts prepared later in 2021.

Additionally, as described in FEI's peak demand forecasting methodology explained in Section 3.3.1 of the Updated Application, FEI dampens the effect of any one year's variation through a process of averaging the results of the previous three years. Therefore, FEI expects that UPC_{peak} will not materially increase or decrease in response to the pandemic. Any change in the new peak demand forecast would be largely due to changes in the customer account forecast driven by CBOC and HHF growth rates that have not yet been received.

2.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, pp. 24, 25, 28

Minimum Inlet Pressure at Gate Stations

On page 24 of the Updated Application, FEI states:

> FEI designs the ITS to deliver a minimum inlet pressure of 2415 kPag (350 psig) into the major gate stations serving downstream Intermediate Pressure (IP) systems on a peak day. This minimum pressure is the parameter that defines the ITS capacity limit. This minimum pressure is identified as the primary capacity constraint for this region in order to maintain a 350 kPag (50 psig) working pressure differential across Polson Gate Station and Kelowna #1 Gate Station that supply IP systems that operate at 2070 kPag (300 psig), supplying thousands of customers. This minimum delivery pressure ensures a reasonable working pressure across the station always exists to accommodate effective sizing and operation of the station regulators and other station equipment.

On page 25 of the Updated Application, FEI states:

> These pressure-controlled regions are identified in Table 3-1 above, with the segments most relevant to the OCU Project listed in rows 2 to 5. These portions of the pipeline can provide a local constraint on capacity. The most significant constraint on maintaining minimum pressure into the north and central Okanagan is the pressure limitation to 5171 kPag (750 psig) between Ellis Creek Control Station in Penticton and the SN9-3 Control Station south of Kelowna. The OCU Project will address this constraint by providing the ability to supply gas into the NPS 12 Savona to Penticton mainline at the maximum 5171 kPa at a point more than 28 kilometres closer to the major load centres on the ITS in the Central Okanagan.

On page 28 of the Updated Application, FEI states:

> The first regions to experience a capacity shortfall would be the communities of West Kelowna, Lavington, and Lumby (shown in Figures 3-9 and 3-10 above). The systems in these communities are supplied by the Kelowna #1 Gate Station and the Polson Gate Station, which require inlet pressures sufficient to maintain an adequate pressure differential between transmission inlet pressure and discharge pressure. Due to their approximate midpoint location on the ITS mainline, the inlets of both stations experience the lowest pressures experienced on the ITS, and current forecasts indicate that the inlet pressures would be insufficient to operate the stations in the case of extreme cold conditions during the winter of 2023/2024. Customers served by the Kelowna #1 Intermediate Pressure system currently number approximately 16,300 in West Kelowna and the customers served by the Polson Intermediate Pressure system in Vernon number over 2,000 in Lavington and Lumby.

2.1 Please explain if the minimum inlet pressure of 2415 kPag (350 psig) is uniform for all major gate stations on the ITS.

2.1.1 If not, please explain the factors that contribute to variations in minimum inlet pressure.

Response:

An inlet pressure of approximately 2420 kPa (350 psig)[1] is the minimum inlet pressure for gate stations supplying intermediate pressure (IP) systems operating at 2070 kPa. The required inlet pressure is related to the downstream operating pressure of the system the gate station is supplying. Gate stations with lower operating pressure in the downstream system can have lower inlet pressure requirements.

Allowing sufficient pressure differential across the regulating station (minimum inlet pressure minus downstream system operating pressure) provides flexibility during the station design to more-economically size equipment and the overall facility. This is because equipment sized for very low pressure differentials is typically larger and more costly, and otherwise presents constraints when designing new stations or upgrading existing stations. For this reason, FEI has identified 2420 kPa as the appropriate minimum pressure to preserve design flexibility for these stations.

The minimum inlet pressure requirements for the Kelowna #1 and Polson Gate Stations supports a minimum 350 kPa (inlet = 2420 kPa to outlet = 2070 kPa) pressure differential across the station. Between Savona and Penticton, in addition to the two gate stations identified in the Updated Application, there are two additional gate stations in Kamloops, and one additional gate station in Kelowna supplied from the ITS. These stations all serve 2070 kPa IP systems and share the minimum inlet pressure of 2420 kPa. The majority of the remaining gate stations on the ITS directly serve distribution systems that operate with lower operating pressure (420 kPa), and therefore can accommodate lower inlet pressures.

2.2 Please discuss whether there have been any instances in the past ten years where inlet pressure into the into the major gate stations on the ITS has been below the minimum inlet pressure of 350 psig.

2.2.1 If so, please describe the circumstances causing such instances, and the impacts upon the downstream system.

Response:

In the past ten years, FEI has not experienced inlet pressures below the minimum 350 psig at the inlet to the major gate stations on the ITS during periods of high system demand when this

[1] The 2415 kPa referenced in the Updated Application was an approximate conversion of 350 psig.

low pressure would cause a concern for maintaining supply to the downstream system. FEI has therefore not experienced any impacts upon downstream systems.

However, the inlet pressure to a gate station is not the sole indicator of insufficient capacity at the station. During periods with low system demand, inlet pressures around 350 psig may not be a concern as the low system flow may not require high inlet pressure to maintain operation of the system downstream of the station. It is during high flow conditions driven by peak demand where it is most critical to ensure inlet pressure is maintained above a minimum threshold. A gate station's capacity to deliver the required flow (and hence maintain pressure into the downstream system) reduces as the inlet pressure to the station reduces.

2.3 Please explain the extent to which the inlet pressure observed at the Kelowna #1 Gate Station and the Polson Gate Station is affected by (i) the peak demand on the entirety of the ITS system, and (ii) the peak demand in localized areas of the ITS system.

Response:

The pressures observed on the ITS at the Kelowna #1 and Polson Gate Stations are influenced (lowered) to some extent by any peak demand load that is added to the ITS and that is not upstream of a pressure control station or compressor station that is actively controlling pressure. In the case of Kelowna #1 and Polson Gate Stations, this region would extend from the discharge of the Savona Compressor Station in the northwest, to the outlet of the current Ellis Creek Pressure Control Station in Penticton. Although there are additional pressure control stations within this area (creating the pressure controlled regions outlined in Table 3-1 of the Updated Application), under peak demand the regulators at these stations are "wide open" and do not restrict the flow of gas or provide any pressure control function because the inlet pressure is lower than the station set-point. Load on the ITS outside of this area, primarily south of Ellis Creek and east of Oliver through the west and central Kootenays, does not currently directly influence pressure at the Kelowna #1 or Polson Gate Stations because of the pressure reduction at Ellis Creek to 750 psig. However, the ITS load in this area does factor into the future capacity requirements to serve the Okanagan, such as future compression upgrade requirements at the Kitchener Compressor Station (as discussed further in the response to BCUC IR1 12.1).

Peak demand in localized areas of the ITS is more influential on the pressure at Kelowna #1 and Polson Gate Stations the closer those localized areas are to either of the two gate stations because the gas is flowing a longer distance. For example, a load addition to the ITS at Kamloops, would have less impact on the pressure at Polson Gate or Kelowna #1 Gate Stations than a load addition at Armstrong (just north of Vernon). This is because there is a penalty in terms of pressure loss in the downstream system for every kilometre a unit of energy in the form of natural gas is required to flow in the system. For a unit of gas delivered from Savona to Kamloops, the pressure loss per kilometre associated with that delivery (and its associated pressure impact at Polson Gate) stops once the gas has been delivered the approximately 32 kilometres from Savona to Kamloops. If that same quantity were instead delivered to Armstrong, moving the gas continues to have a cost in terms of higher pressure loss per kilometre for the additional 100 kilometres it travels beyond Kamloops to arrive at Armstrong. More distant local areas served directly through Kelowna #1 and Polson Gate Stations, such as West Kelowna, Lavington, or Lumby have an even greater effect on inlet pressure at these gate stations.

2.4 Please discuss whether the minimum inlet pressure at major gate stations may be affected by future increases in demand.

Response:

As described in the response to BCUC IR1 2.3, future increases in demand will reduce the inlet pressure at gate stations throughout the system. If the question is directed at whether future increases in demand would cause FEI to adjust the minimum inlet pressure used as a system design parameter, the response would be no.

2.5 Please provide graphs for the Kelowna #1 Gate Station and the Polson Gate Station which show from 2019 to 2039 the forecasted inlet pressure under forecasted peak day conditions in the absence of the OCU Project.

Response:

Figure 1 below shows the station inlet pressure of major ITS gate stations from 2019 to 2024 under forecast peak day conditions in the absence of the OCU Project. Figure 2 shows the minor improvement that would result from increasing the Savona tap pressure from 600 psig to 650 psig in 2022 to offset the pressure decay for a period of time. Beyond 2024, the hydraulic model no longer converges, which indicates that the system would effectively collapse to zero pressure under the sustained peak day load.

In the forecast period starting from 2020, the inlet pressure at Polson Gate will fall below the minimum design pressure of 350 psig and would continue to decay in the absence of the OCU Project. FEI will apply short-term mitigation measures to ensure the downstream systems are able to continue to operate safely and reliably until the completion of the OCU Project.

The rate of pressure decay illustrates the limited timeframe FEI has to implement mitigation measures before a critical point is reached. The pressure decay becomes more pronounced each year as the decay is nonlinear, and hence accelerates as the pressure declines.

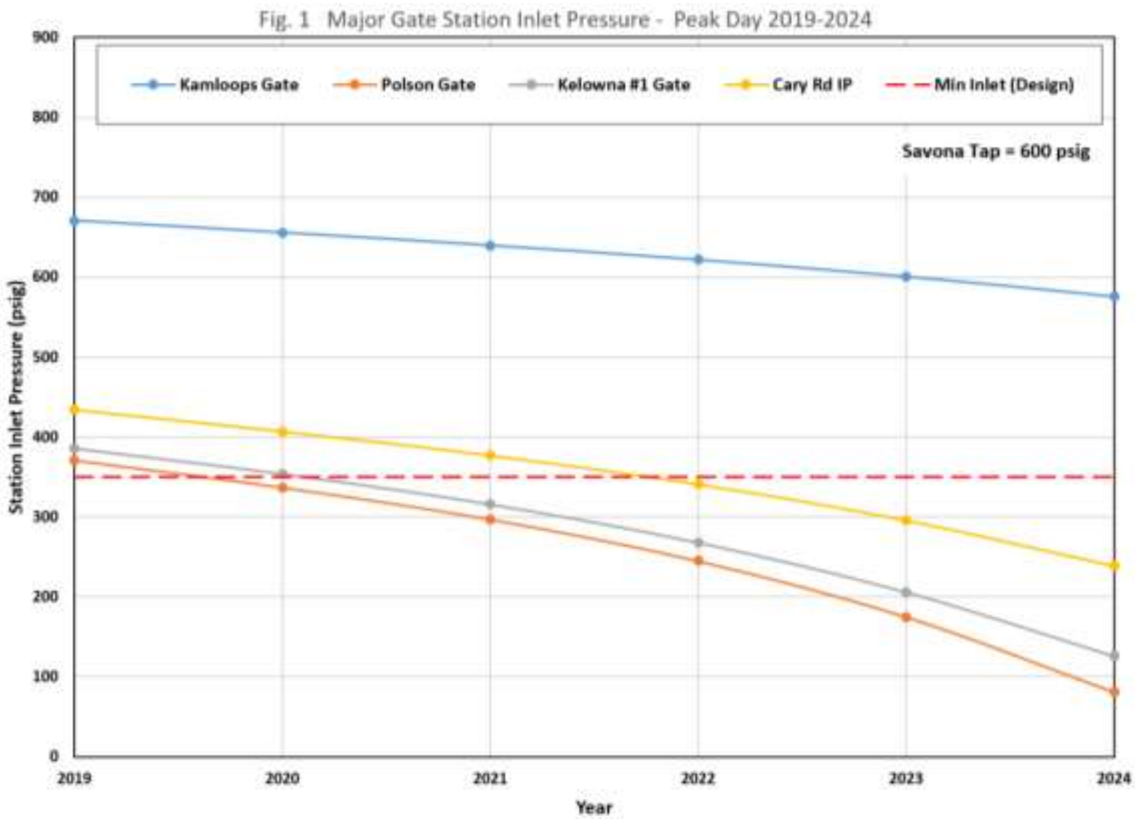


Fig. 1 Major Gate Station Inlet Pressure - Peak Day 2019-2024
Kamloops Gate
Polson Gate
Kelowna #1 Gate
Cary Rd IP
Min Inlet (Design)
Savona Tap = 600 psig
Station Inlet Pressure (psig)
Year
0
100
200
300
400
500
600
700
800
900
2019
2020
2021
2022
2023
2024

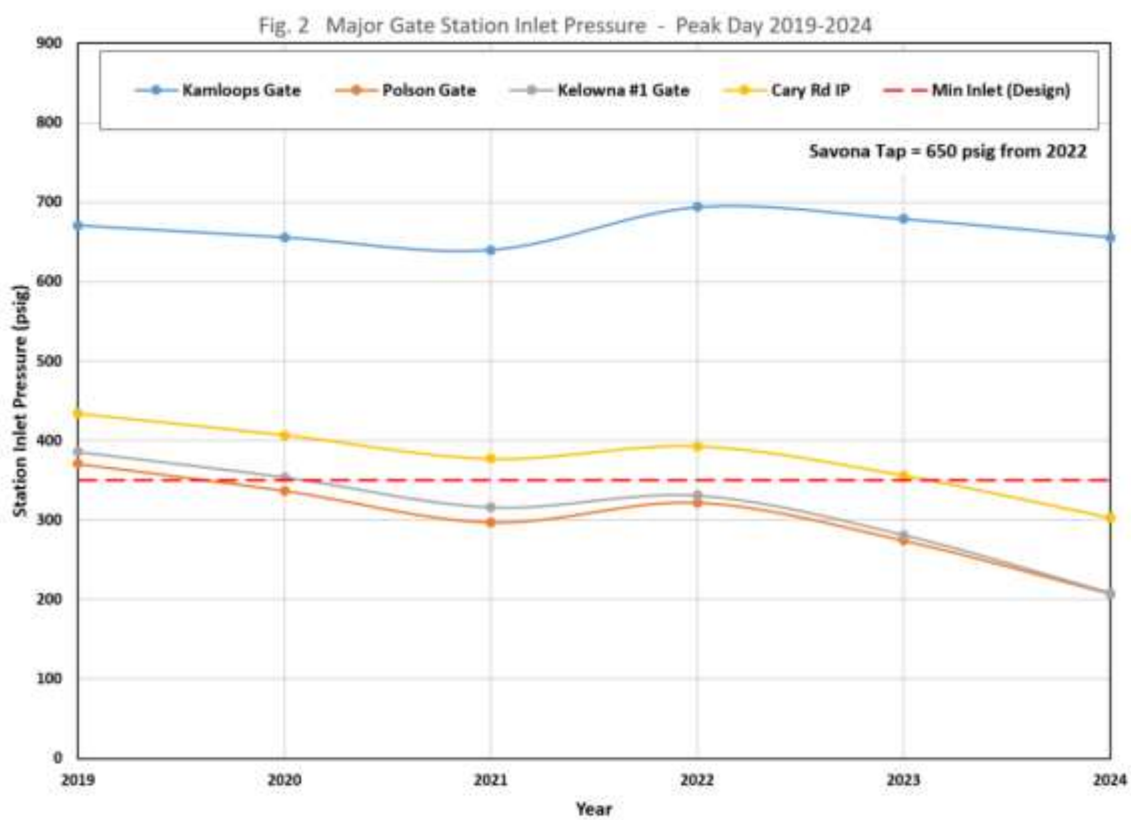


Fig. 2 Major Gate Station Inlet Pressure - Peak Day 2019-2024
Kamloops Gate
Polson Gate
Kelowna #1 Gate
Cary Rd IP
Min Inlet (Design)
Savona Tap = 650 psig from 2022
Station Inlet Pressure (psig)
Year
0
100
200
300
400
500
600
700
800
900
2019
2020
2021
2022
2023
2024

2.6 Please confirm or explain otherwise that the OCU Project is not solely designed to address the potential capacity shortfall in the communities of West Kelowna, Lavington, and Lumby.

Response:

Confirmed. The communities mentioned, served by the Kelowna #1 and Polson Gate Stations, would be the first to experience impacts. Left unaddressed, the impact of insufficient system capacity would spread along the ITS from those major gate stations impacting other customers in nearby regions such as Greater Kelowna, Lake Country, Vernon, and Coldstream.

2.6.1 Please discuss whether FEI considered alternatives that would specifically address the forecasted capacity shortfall in the communities of West Kelowna, Lavington, and Lumby only.

2.6.1.1 Please discuss the pros and cons of such an approach.

Response:

FEI considered alternatives to address the forecast capacity shortfall at a local level in the communities of West Kelowna, Lavington, and Lumby. However, these alternatives are not viable long-term solutions for the ITS and do not provide the reliability, resiliency, and operational benefits to the ITS outside of these local areas. The proposed OCU Project will not only provide a capacity enhancement that is available year round to support peak demand, but it will also enhance the way the system can be configured in lower demand periods to support operations and maintenance work on the ITS within the Thompson and Okanagan region.

The capacity shortfall at a local level could be managed in two ways: by supplementing the supply deficit locally with compressed natural gas (CNG) or liquefied natural gas (LNG), or by curtailing local load to match the available supply.

CNG/LNG Supply Augmentation

As explained in the response to BCUC IR1 2.6, the communities of West Kelowna, Lavington, and Lumby are just the first communities that would be impacted. As such, when considering a localized CNG/LNG solution, initially at least two locations would need to be addressed, one on the West Kelowna IP system and another on the Polson IP system serving both Lavington and Lumby. Local CNG/LNG injection would be needed to meet two objectives: first, to meet the local increase in peak demand, and second to compensate for any inlet pressure reduction at the gate station serving the system caused by growth in other areas along the ITS. Taking

West Kelowna as an example, CNG/LNG injection could be supplied to manage the peak day deficit in year one. In year two, more CNG/LNG would be required to meet the increased demand of new customers in the West Kelowna area, but additional CNG/LNG would be needed to overcome the reduction in inlet pressure at the Kelowna #1 Gate Station caused by demand growth in other communities along the ITS. Consequently, the quantities required to be available on a peak day would escalate year over year because of local growth but also because of system growth. Eventually, supplementation would be required on days warmer than a peak day, further increasing the volumes required to be stored onsite and delivered into the systems. To be a permanent solution, the facility would need to be constructed large enough to serve the forecast future demand. A similar approach would be needed for the Polson IP system. Transportation in the form of LNG rather than CNG would be more effective because of the lower storage volumes. In order for the two facilities to be effective well into the forecast period, each would be smaller in scale than the LNG facility described in Alternative 5 of the Updated Application (the LNG facility alternative proposed, but not selected), but still larger than the local community need. Combined, the two facilities would be less useful and beneficial for the system than Alternative 5, or the preferred OCU Project pipeline.

Customer Load Curtailment

Curtailing customer load locally to address the supply deficit caused by the capacity shortfall is not considered viable by FEI and would have similar increasing requirements as those described above. FEI does not consider it appropriate to design or operate its system by relying on curtailment of firm customers to maintain the required minimum system pressures. If FEI were to consider curtailing locally, as new customers are added to the local systems each year the increasing peak demand would increase the curtailment requirements year over year. Additionally, in order to alleviate inlet pressure decreases at gate stations caused by system growth in other areas, further curtailment would be required each year. The most effective curtailment for maintaining inlet pressure at the Kelowna #1 Gate Station would be to curtail customers in the West Kelowna system. Customers in other areas could be curtailed to maintain the inlet pressure, but as described in the response to BCUC IR1 2.3, changes in peak demand in more distant locations of the system are less influential on the inlet pressure. So there would be incentive to target customers for curtailment based on their location. FEI has no means of managing a mass curtailment of customers in a local system. The most effective target customers considered for curtailment would be large volume customers where the curtailment effect could be more easily quantified and managed. In a local system, there are limited numbers of such customers to target in order to achieve the increasing curtailment required and manage the capacity deficit over a number of years. Over time, such an approach would create service level inequities and result in security of supply concerns for customers in these local areas compared to the remainder of FEI's customers.

In summary, while addressing the capacity deficit on the ITS at a local level could have some short-term benefits, over the long-term it is not considered a feasible solution for the OCU Project. Addressing the deficit by installing local supply would ultimately require multiple facilities to be operated and maintained, and each would be significantly larger in scale than the initial needs to meet escalating future requirements. Any operational benefits would be more localized and less useful to support operations work on the system elsewhere. Addressing the issue by curtailing local customer demand would provide no operational benefit to the ITS, and there is no means in the gas distribution system to apply targeted curtailment to the local customers. Finally, this approach would place the burden of insufficient system capacity on a group of FEI customers who would be disadvantaged simply because of the community in which they are located.

2.7 Please provide a table which identifies for each major gate station on the ITS; the first year in the forecast period where, in the absence of the OCU Project, forecasted inlet pressure would fall below the minimum inlet pressure of 350 psig under peak day conditions at the gate station; and the number of customers served downstream of the gate station.

Response:

The table below shows the year each gate station in the affected area would fall below 350 psig, and the number of customers served downstream of the gate station. In the short term, FEI will employ mitigation measures described in Section 4.2 of the Application to ensure continued supply to downstream customers. However, as discussed in the response to BCUC IR1 2.5, the hydraulic model fails to converge (i.e., the pressure decays to zero in this area) after 2024. As a result, FEI is unable to model any further pressure decay to other stations on the system.

Gate Station	Year Winter Peak Day Pressure < 350 psig	Winter Peak Day Mitigation Measures Insufficient	Customers Served (currently)
Polson Gate	Winter 2020-21	Winter 2023-24	2,000
Kelowna #1 Gate	Winter 2020-21	Winter 2023-24	16,300
Cary Road Gate	Winter 2022-23	Winter 2023-24	9,000

2.7.1 Please also provide this information in the scenario where the OCU Project is constructed but no other capacity upgrades are undertaken in the forecast period (if applicable).

Response:

Following completion of the OCU Project, FEI has identified the next required capacity upgrade in the forecast period as the Kitchener B Compressor Station. In the absence of this compressor upgrade, after 2029, the delivery pressure of the OLI PEN 406 pipeline will increasingly degrade below the minimum required 1135 psig at the Oliver Y Control Station (Oliver). This pressure is required at this point in the ITS to ensure that Oliver can continue to supply the two pipelines leaving that facility and which operate at an MOP of 1135 psig: the Kingsvale Oliver pipeline (required to deliver 105 MMscfd to the Enbridge system at Kingsvale), and the South Okanagan Natural Gas pipeline that feeds the OCU Project pipeline. If this pressure degradation is not addressed, the Polson Gate Station inlet pressure would fall below 350 psig by 2037 as identified in the table below.

Gate Station	Year Winter Peak Day Pressure < 350 psig	Customers Served (currently)
Polson Gate	Winter 2037-38	2,000

Other gate stations would remain above the minimum 350 psig requirement in the forecast period. Please also refer to the response to BCUC IR1 12.1 for a discussion of FEI's future gas supply strategy for the ITS.

3.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, p. 25

FEI 2017 Long Term Gas Resource Plan proceeding, Exhibit B-1, pp. 152, 153

Line Pack

On page 25 of the Updated Application, FEI states:

> The successful application of line pack to supplement the system capacity relies on sufficient periods of lower system demand to occur where input into the system can exceed current demand and rebuild the line pack within the system to be available for future periods of peak demand. The ITS experiences continuous daily cycles in demand where line pack is constantly in flux alternating between periods of depletion followed by periods of regeneration. FEI accounts for this capability by applying the transient factor to the peak demand. The transient factor adjusts the magnitude peak load used for system design to a value lower than the hourly peak demand actually experienced on the system on a peak day, reflecting that the balance can be provided by the system line pack.

On pages 152 to 153 of the FEI 2017 Long Term Gas Resource Plan (LTGRP), FEI stated:

> Designing transmission systems to meet peak demand. Core demand varies on an hourly basis and typically exhibits a morning peaking period between six and ten a.m. and an evening period between five and nine p.m. The peak hour demand for these customers can be more than 40 percent above the hourly average (daily demand/24 hours). Transmission systems are designed to meet this peak demand condition.
>
> …
>
> The amount of line pack within a transmission system determines whether it should be designed to meet peak day or peak hour conditions. A pipeline system with a large relative line pack can temporarily support increased demand out of the system that exceeds the supply into the system. As demand exceeds supply the amount of gas “packed” in the pipeline (i.e. line pack) is reduced and pressure in the pipeline is drawn down , until such time that the demand drops below the supply into the system, at which point pressure (and line pack) can recover. Pipeline length and operating pressure determine the amount of line pack available in the system. Typically, longer, larger diameter systems operating at higher pressures with high line pack are designed to peak day conditions; conversely, systems with lower amounts of line pack (due to factors such as lower pressures and smaller volumes) are designed to meet peak hour loads.

3.1 Please confirm, or explain otherwise, that the peak demand forecasts presented in the Updated Application (e.g. in Figures 3-6 to 3-8) reflect the application of the transient factor.

Response:

Confirmed. The peak demand forecast presented in Figures 3-6 to 3-8 reflects the demand modified by the transient factor.

3.1.1 Please discuss whether the transient factor is applied at a system wide level or at a more granular localized level.

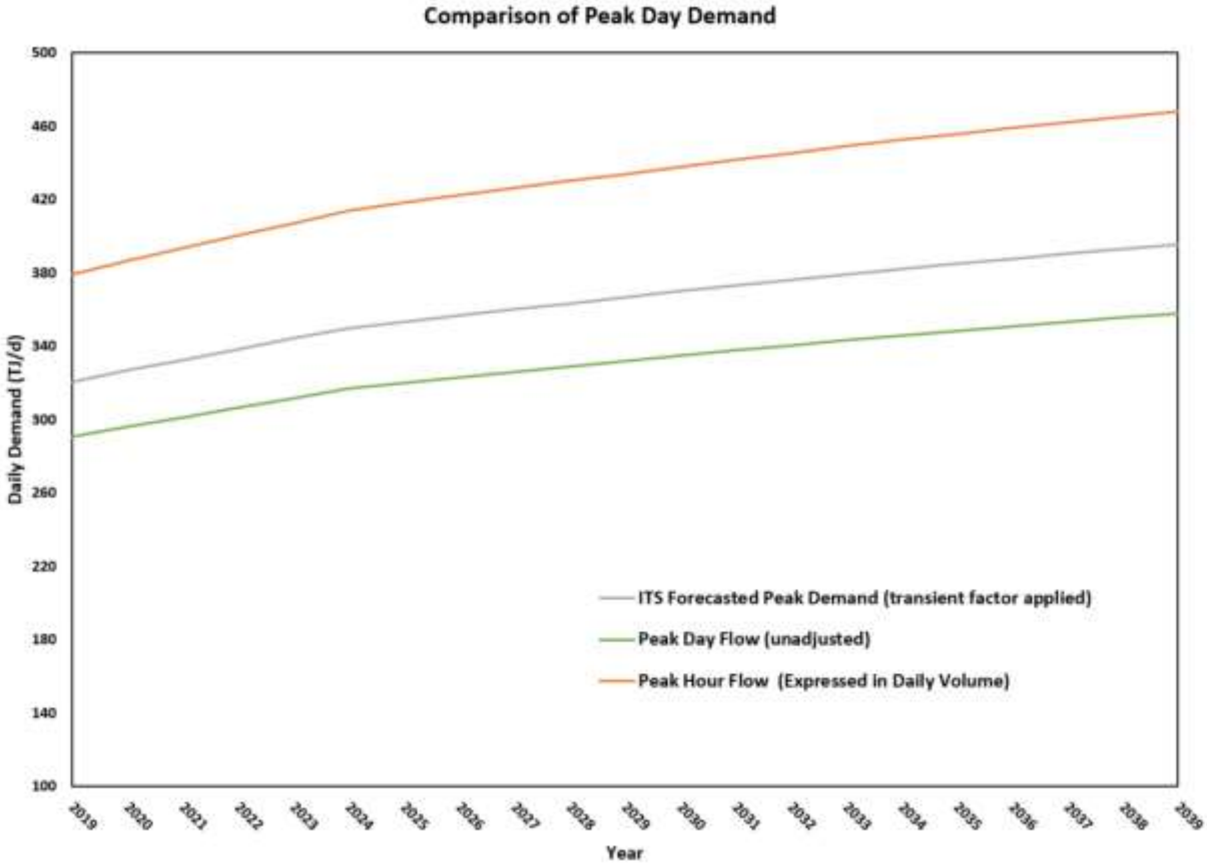
Response:

The transient factor is applied at a system-wide level. The transient factor modifies the load to reflect the effect of line pack which is a property of the larger system and not a specific location.

3.1.2 Please show a comparison of the peak day forecast for the ITS adjusted for the transient factor and unadjusted for the transient factor, for the forecast period. If available, please also provide the peak hour forecast for the ITS.

Response:

The figure below provides the requested comparison. The middle curve is the ITS peak demand forecast provided in the Updated Application.



3.2 Please discuss why peak day is a more appropriate measure for capacity planning on the ITS than peak hour.

Response:

Although described as a peak day measure, the ITS loading, when a transient factor is applied, provides peak demand load that falls between a peak day load with no factor applied (representing the daily average load each hour with no variation through the day) and the higher peak hour load. The peak hour demand is the highest system peak of the day and typically occurs in the morning hours just as residential and commercial loads begin to come online following the overnight period. Please refer to the figure in the response to BCUC IR1 3.1.2 for a comparison of the relative variation in peak demand loading. FEI refers to this approach (i.e. applying the transient factor) as a "peak day" loading but it is a generalization that implies that the effects of available line pack over the day are considered. On systems such as ITS, where the configuration provides available line pack, using a peak hour loading would result in under estimating the available capacity and would identify capacity constraints at a lower loading (earlier in a peak demand forecast) than the system is actually capable of supporting. Therefore "peak day" load modified by a transient factor is more appropriate measure for assessing capacity on the ITS.

3.2.1 Please explain whether periods of low line pack coincide with periods of highest demand on the ITS.

Response:

Yes, periods of low line pack coincide with periods of highest demand on the ITS. Line pack is a function of the average pressure in the system. During periods of high demand, the pressure along the ITS will drop, and so periods of high demand result in lower pressures at each point along the system and thus lower line pack.

3.2.2 Please discuss whether there are any localized points on the ITS with typically low line pack where peak hour demand may be more relevant for capacity planning purposes than peak day.

Response:

Along the length of the ITS mainline, peak day demand modified by the transient factor is most relevant for capacity planning purposes. However, there are locations where smaller laterals that extend from the ITS mainline result in a locally reduced available line pack. Locations such as the Kelowna #1 Lateral and the Coldstream Lateral (supplying Polson Gate Station) are 2.1 and 5.9 kilometres in length, respectively, and have a smaller diameter than the ITS mainline. These laterals have less available line pack to moderate the pressure drop along their length. However, FEI includes these laterals in the ITS models and applies the peak day loading modified by the transient factor. FEI compensates for the higher pressure drop locally that would occur in these laterals on the peak hour by adjusting a parameter referred to as the "pipe efficiency" for the lateral.

3.2.3 Please describe the line pack characteristics of the pipelines feeding the Kelowna #1 Gate Station and the Polson Gate Station.

Response:

Please refer to the response to BCUC IR1 3.2.2.

3.3 Please explain whether FEI must consider the duration of a peak winter event beyond the peak day in its system capacity planning on the ITS.

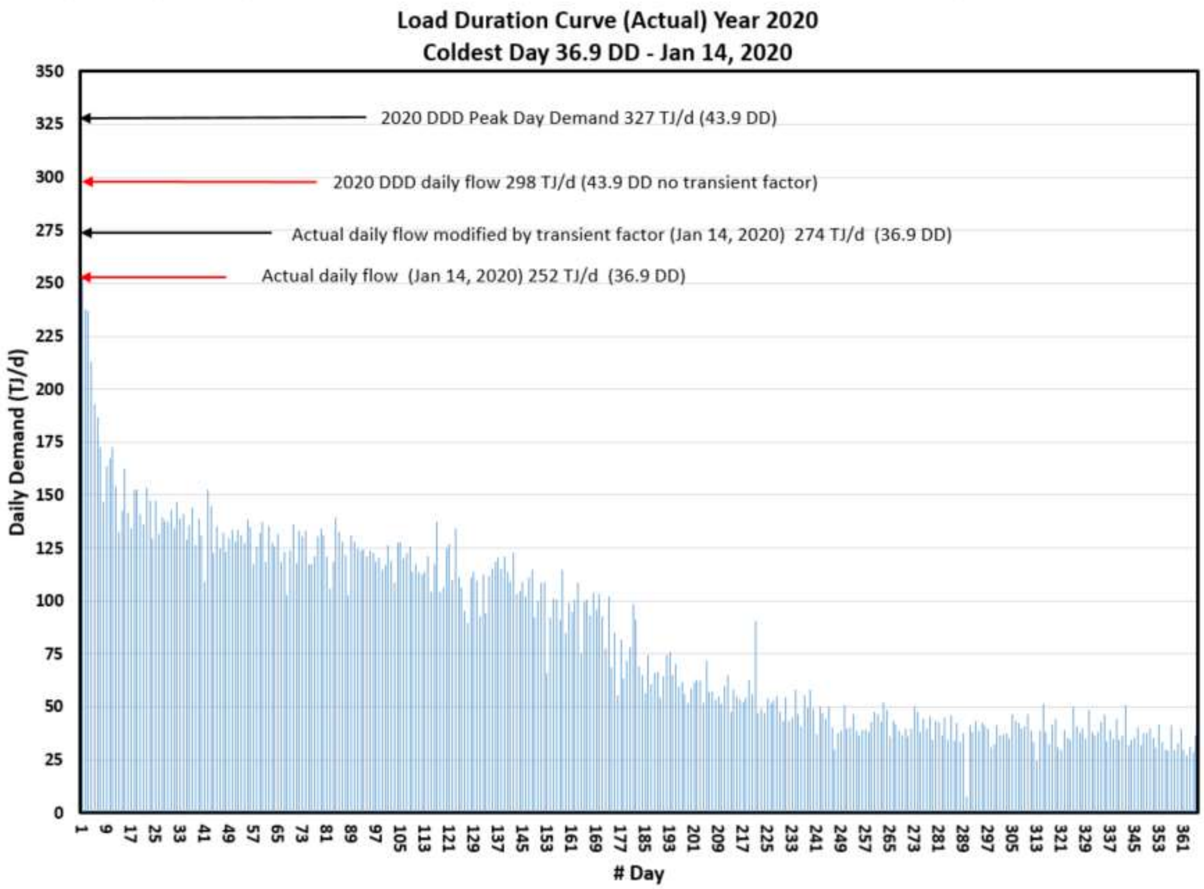
Response:

FEI does not consider the duration of a peak winter event for designing the system capacity with respect to any pipe and compression facilities required to meet a peak day. The design for these facilities, to the extent that they rely on rebuilding line pack in the off peak part of the day, does not require subsequent non-peak days to recover. As a result, the system is designed to support back-to-back peak days should they occur. For peak shaving facilities like the LNG facilities proposed in Alternative 5, the sizing of the vapourizer facilities for gas send-out would likewise meet the need for recurring peak days if needed. The duration and severity of winter peak events would be a factor in determining appropriate LNG storage volumes required at such a site to support extended peak demand. A load duration curve representing an extremely cold winter would be a consideration in the design of an LNG peak shaving facility.

3.3.1 Please provide a load duration curve showing the daily peak demand on the ITS for the year with the coldest peak day observed in the last five years.

Response:

The figure below presents the load duration plot of daily demand in the ITS for 2020, the year with the coldest day observed in the last five years. The demand for the coldest day and then for each successively warmer day is laid out left to right representing each day of the year. The degree day (DD) on the coldest day was a 36.9 DD (-18.9 º C recorded at the Kelowna Airport on January 14, 2020). The peak load that day was 274 TJ per day. The red arrows indicate the demand in unadjusted form for the flow on January 14, 2020 and the expected flow on a design degree day (DDD). The black arrows represent the flow adjusted by the transient factor and reflect the actual flows and the expected flow on a DDD as they would be presented against the ITS peak demand in Figures 3-7 or 3-8 of the Updated Application. The variation in daily flows through the year, including during warmer periods, show how industrial demand can vary and influence recorded system demand on days with similar weather.



Load Duration Curve (Actual) Year 2020
Coldest Day 36.9 DD - Jan 14, 2020
2020 DDD Peak Day Demand 327 TJ/d (43.9 DD)
2020 DDD daily flow 298 TJ/d (43.9 DD no transient factor)
Actual daily flow modified by transient factor (Jan 14, 2020) 274 TJ/d (36.9 DD)
Actual daily flow (Jan 14, 2020) 252 TJ/d (36.9 DD)
Daily Demand (TJ/d)
Day

4.0 Reference: PROJECT NEED AND JUSTIFICATION

FEI 2017 LTGRP proceeding, Exhibit B-1, p. 154

End-use Peak Load Forecasting

On page 154 of the 2017 LTGRP, FEI stated:

> FEI has since commissioned Posterity, a consultant, to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. At this point, the exercise is theoretical in nature and unsupported by direct measurement. As such, FEI's infrastructure planning continues to rely on the Traditional Peak Method. The exploratory end-use method does, however, provide a means of assessing a range of peak demand forecast possibilities and the impact on system capacity upgrade project scope and timing.

4.1 Please explain whether FEI has conducted analysis of the link between end-use demand forecasts and peak demand for the ITS system as part of its assessment of the need for the Project.

<u>Response:</u>

No. FEI used its Traditional Peak Method forecast to assess the Project need and timing and believes that forecast, derived from FEI monthly consumption data, remains the best available. FEI has not conducted any analysis for the Project using a range of alternate forecasts based on end-use methods as the end-use forecasts still remain theoretical and unverified by hourly metered data. Without direct hourly measurement for residential and commercial customers, FEI has no evidence to support that theoretical modifications to peak demand based on future end-use changes would be reasonable. Please also refer to the response to BCUC IR1 4.1.2.

4.1.1 If yes, please provide a summary of this analysis, and explain the extent to which it supports the peak demand forecast used in the Application.

<u>Response:</u>

Please refer to the response to BCUC IR1 4.1.

4.1.2 If no, please compare the peak demand forecast presented in the Updated Application with the end-use peak demand analysis provided for the ITS in the FEI 2017 LTGRP, and discuss any significant differences between the two forecasts.

Response:

In the 2017 LTGRP, FEI presented a range of end-use forecasts in addition to the traditional peak demand forecast. The forecasts used in the 2017 LTGRP had a base year of 2015, meaning the forecast started with total connected accounts as of December 31, 2015. Accounts and demand for years 2016 and beyond included forecast amounts. This compares to the forecast used in the Updated Application that had a base year of 2018 starting with total connected accounts as of December 31, 2018 and with accounts and demand for years 2019 and beyond including forecast amounts. In the years between the two forecasts, FEI recorded three consecutive years of net customer attachments that exceeded the forecast used in the 2017 LTGRP, with 2018 being an all-time high for FEI in customer attachments. As a result, the 2019 customer account forecast started from a 2018 year end account total that exceeded the range of forecasts used in the 2017 LTGRP. Therefore, the 2019 peak demand forecast also increased above the peak demand forecasts used in the 2017 LTGRP.

As discussed on pages 154-155 of FEI's 2017 LTGRP[2], the end-use method is theoretical and not based on metered FEI data. The end-use forecasts and the traditional FEI forecast all underestimated the peak demand load in 2019 by at least 15 TJ compared to the forecast used in the Updated Application. Some end-use forecasts predicted declining loads. Three of the six forecasts predicted no capacity constraint in the forecast period. Regardless, the FEI traditional forecast and the Upper Bound end-use forecast were the closest estimate to the current projected demand. Of the increase in ITS peak demand of 15.7 TJ in 2019 above the highest 2017 LTGRP forecasts, 4.4 TJ/d is associated with the net increase in residential customers, 8.3 TJ/d is associated with small and large commercial rates schedules and 2.9 TJ/d is associated with customers in the industrial rate schedules. As a result of the high customer attachments in the period preceding the 2019 forecast and with FEI's commercial account forecasting method using a three-year average for commercial accounts, there is a sustained higher growth rate for commercial accounts. This results in a higher growth rate in the current 2019 peak demand forecast than was present in the forecast used for the 2017 LTGRP. The factors influencing the current forecast upward compared to the traditional and end-use forecasts increased pressure on the timing for the OCU Project and resulted in the increasing need to manage the Project timing with short-term mitigation measures.

While the end-use forecasts used in the LTGRP provide a means of studying some potential variation in how a peak demand forecast may change as a result of end-use influences, as mentioned previously, the method for imposing the variation is theoretical. Currently, the forecast produced by the method predominantly underestimates FEI's current peak demand by a larger margin than the traditional forecast methods. FEI believes the end-use method needs some basis in direct measurement of FEI customers' usage that presently is not available. Until such time as FEI is able to collect discrete customer consumption more widely, FEI believes

[2] https://www.fortisbc.com/about-us/corporate-information/regulatory-affairs/our-gas-utility/gas-bcuc-submissions/fortisbc-energy-inc.-gas-submissions/LTGRP/2017-resource-plan-for-natural-gas

that the end-use forecasts are insufficient to project peak demand for the purpose of planning capacity infrastructure. FEI will be submitting a CPCN application for its Advanced Metering Infrastructure Project later this year which, if approved, could provide individual customer metering data that would support a better understanding and application of end-use peak demand forecasting.

4.1.3 Please briefly explain the strengths and weaknesses of end-use peak demand forecasting with respect to system capacity planning.

Response:

Please refer to the response to BCUC IR1 4.1.2.

5.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, pp. 20, 21

BC Office of Housing and Construction, Provincial Policy: Local Government Implementation of the BC Energy Step Code, p. 4

Use Per Customer

On page 20 of the Updated Application, FEI provides the formula used for forecasting peak day demand:

> The calculation of the forecast peak day demand in any year can be described by the following formula:
>
> $$Peak\ Day\ Demand_{(Year\ N)} = \sum_{i=1}^{3} (\sum \text{Current Accounts} \times UPC_{peak} + \sum \text{Forecasted Accounts to Year N} \times UPC_{peak})_{(rate\ schedule\ i)} + \sum \text{Industrial Customer Maximum Demand} + \sum \text{Contract Obligations for Interruptible Customers}$$

On page 21 of the Updated Application, FEI states:

> FEI determines the peak demand of residential and commercial customers connected to and consuming gas on the ITS by multiplying the three-year average peak use per customer (UPCpeak) for each rate schedule by the number of current customers in the system in each residential and commercial rate schedule. FEI then multiplies the three-year average UPCpeak for each of the rate schedules by the forecast number of new customer accounts in each rate schedule for each year of the forecast, and adds this to the peak demand for current customers. FEI does not modify the UPCpeak values over the forecast period.

5.1 Please explain the rationale for selecting a three-year average UPCpeak, rather than an average over some longer or shorter period.

Response:

FEI considers the three-year average to be the appropriate balance between stabilizing the UPC_{peak} for system planning, while also reflecting any developing trends between the current consumption and historical results. In determining an appropriate UPC_{peak} for system planning, FEI considers these two competing objectives.

The first objective is to establish a stable value of UPC_{peak} that doesn't vary greatly from year to year and which can be applied to hydraulic models to determine system capacity upgrade requirements, if any. A stable value of UPC_{peak} will result in more consistent determination of projected scope and timing of identified capacity upgrades. FEI uses a process that derives a peak hour value from monthly customer consumption. Year-to-year variations can occur because of the coarseness of the data (monthly readings). Using a three-year average dampens the year-to-year variations to some degree and provides a more stable and consistent result.

The second objective is to have timely recognition of changes in customer utilization reflected in the current value of UPC_{peak}. For example, over time it is reasonable to expect that the average residential customer might become more efficient and the average premise might have a lower UPC_{peak} due to better insulation, more efficient appliances, etc. Using a ten-year or a five-year average would provide a more stable value of UPC_{peak}, but would obscure more recent changes in customer efficiency from being reflected in the UPC_{peak}.

For these reasons, FEI has consistently used a three-year average UPC_{peak} for system planning purposes.

5.2 Please provide a detailed explanation of why the UPCpeak for current customers is assumed to be constant over the forecast period.

Response:

The UPC_{peak} for residential, small commercial, and large commercial customers does change from year to year as new forecasts are developed.

It is reasonable to expect the values to continue to vary over time. The FEI trends presented in the following response to BCUC IR1 5.3 show historical changes over 10 years. Over time, customer activities such as improvements in energy efficiency, changing end-use applications, and possibly fuel switching will impact UPC_{peak}. However, FEI emphasizes that the scope and scale of these activities are currently unknown. There remains uncertainty in the directional impacts on UPC_{peak} of some efficiency technologies like smart learning thermostats or on-demand hot water heaters.

FEI believes that the Traditional Peak Method which holds UPC_{peak} constant through the forecast remains appropriate. This method mitigates risk to FEI and its ratepayers through a process of continual re-evaluation throughout the planning period. The UPC_{peak} values are refreshed annually, and then used in the forecast prepared that year, providing a regular check on the current state of peak demand requirements and potential future impact.

In an environment where UPC_{peak} is increasing, the planning process identifies, year over year, the likely advance in timing of project requirements. The forecast method provides sufficient notice to initiate project planning and execution, such that projects can be installed to meet the identified capacity deficit. The risk to FEI and its ratepayers of potentially large-scale peak day outages or projects being more costly (due to insufficient planning or execution time) is managed through the traditional method. In an environment where UPC_{peak} is decreasing, the planning method again identifies, year over year, any deferral in project need, so reprioritization or re-evaluation of the scope of projects can be undertaken. The traditional planning method in this way mitigates the risk to FEI and its ratepayers of investing in capacity projects before the need is present.

5.2.1 Please describe the main factors FEI considers may contribute to an increase or decrease in the UPCpeak in the forecast period.

Response:

UPC_{peak} is likely to be decreased through energy efficiency measures on existing premises such as increased adoption of high-efficiency appliances, window replacement programs, home insulation programs, and other measures that reduce the instantaneous energy usage, yet provide a similar level of customer comfort. Programs that switch fuel usage away from natural gas to alternate energy forms would similarly reduce UPC_{peak}. As more modern construction of homes and businesses replace older construction, the predominance of more energy efficient structures and appliances would be expected to contribute to a decrease in UPC_{peak}. The directional impacts on UPC_{peak} of some efficiency technologies like smart learning thermostats or on-demand hot water, where energy use may be more concentrated into the periods of the day is less certain. New customers connecting after deciding to replace oil, diesel, propane, and other higher carbon fuels in homes and businesses with natural gas, although not contributing to an increase in $UPC_{peak,}$ may contribute additionally to growth in overall peak demand.

5.3 Please provide the UPCpeak for residential and commercial customers by rate schedule for the last 10 years for customers served by the ITS. Please provide a description and explanation of any observable trends.

Response:

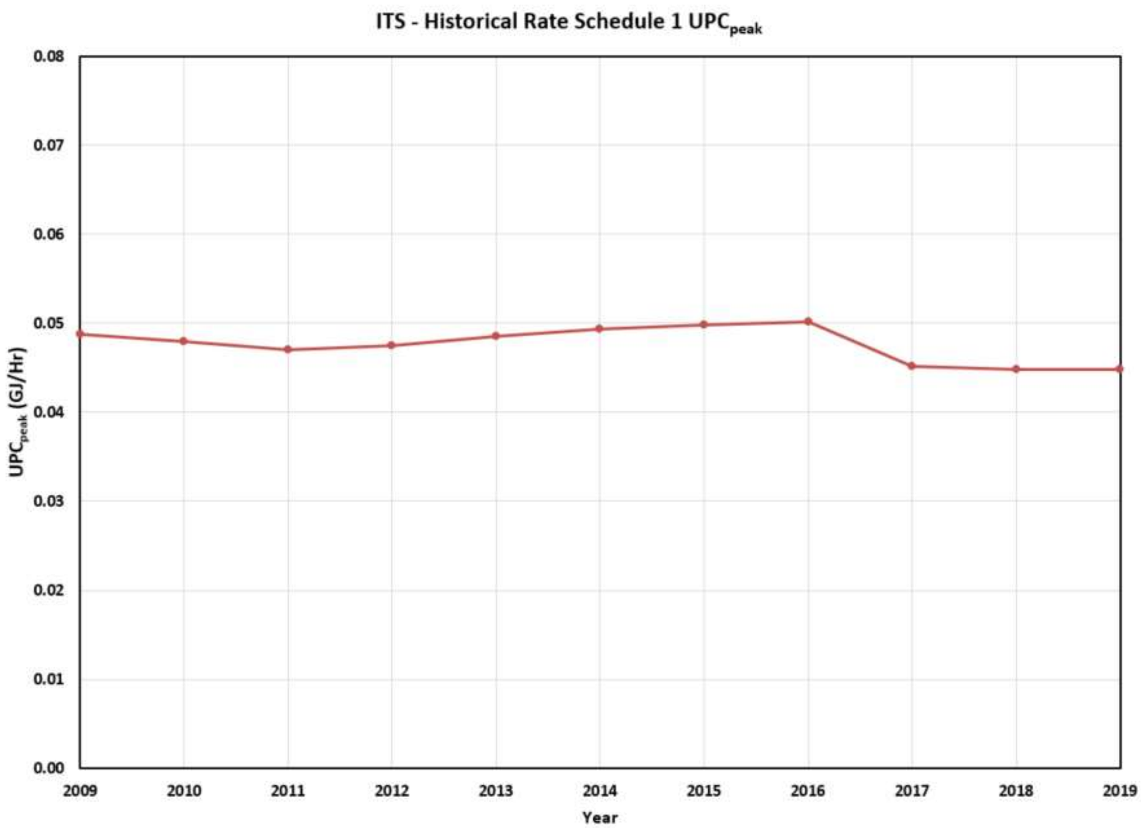
The following table presents the historical UPC_{peak} from 2009 to 2019 for RS1, RS2 and RS3 (residential and commercial) customers served by the ITS. The figures that follow graphically illustrate the changes in UPC_{peak} by rate schedule over time.

In the response to BCUC IR1 8.4, FEI explains that the Design Degree Day (DDD) was recalculated in 2017 based on a more recent 60-year weather history. This resulted in a reduction in the design temperature being used in most regions. The lower DDD result was used from 2017 onward and resulted in lower values in that period than if DDD values had remained unchanged.

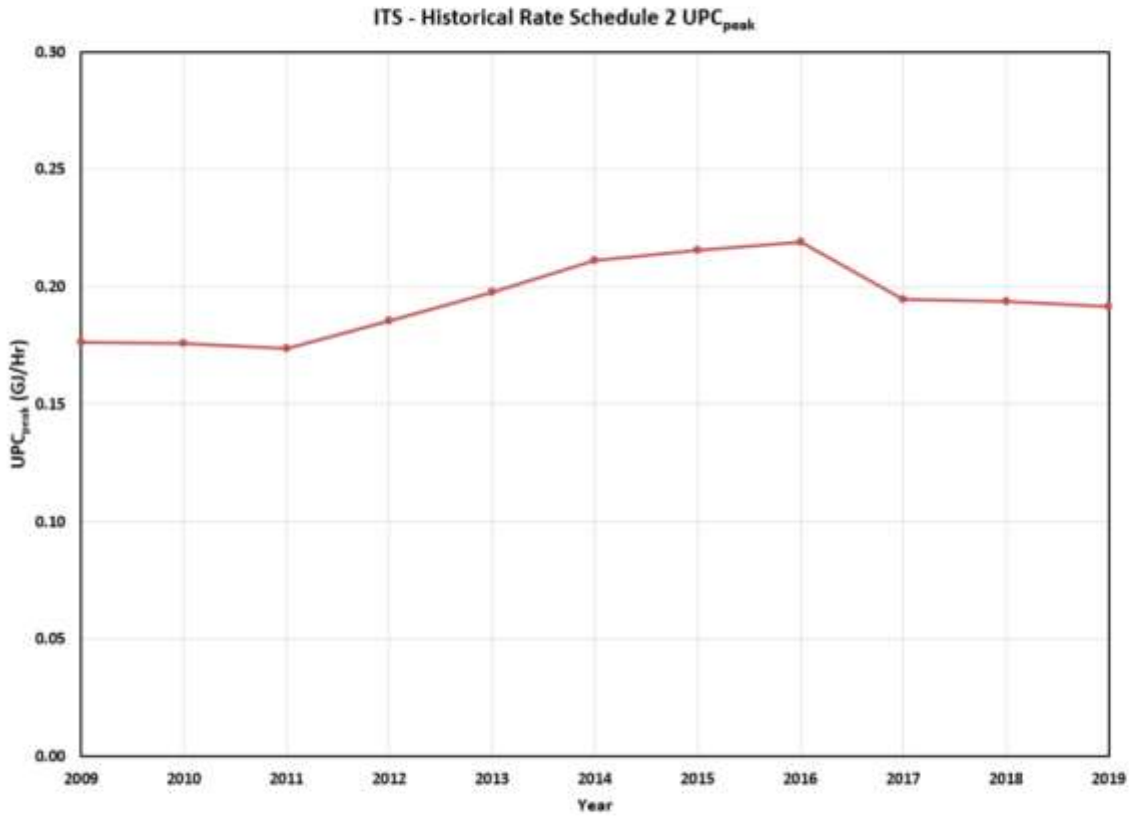
There are no dramatic trends evident in the UPC_{peak} values over time. The UPC_{peak} for RS1 customers drops slightly over the period and mostly in the period from 2017 (primarily due to the DDD change). The UPC_{peak} values for RS2 and RS3 customers have slightly increased when comparing the start and end of the period (even when considering the reduction in DDD), but the trend is also not significant.

ITS Historical UPC_{peak} (GJ/Hr)

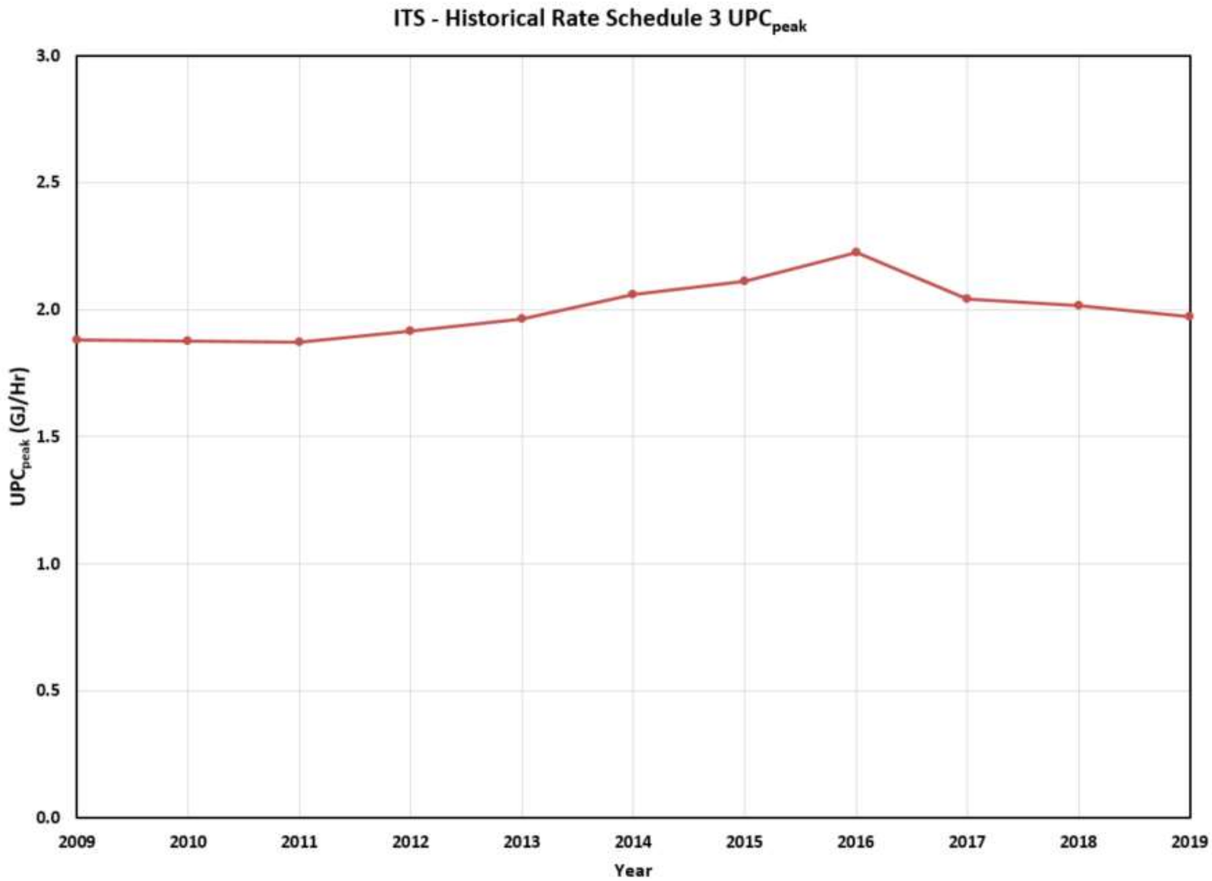
Year	ITS UPC_{peak} (GJ/Hr)		
	RS 1	RS 2	RS 3
2009	0.0487	0.1763	1.8831
2010	0.0479	0.1758	1.8749
2011	0.0470	0.1739	1.8718
2012	0.0475	0.1857	1.9181
2013	0.0485	0.1975	1.9629
2014	0.0494	0.2113	2.0586
2015	0.0499	0.2155	2.1111
2016	0.0502	0.2190	2.2240
2017	0.0452	0.1946	2.0447
2018	0.0449	0.1937	2.0176
2019	0.0448	0.1918	1.9723



1



ITS - Historical Rate Schedule 2 UPCpeak
UPCpeak (GJ/Hr)
0.30
0.25
0.20
0.15
0.10
0.05
0.00
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Year



5.4 Please explain why the UPCpeak for new customers is assumed to be the same as existing customers.

Response:

As explained in the response to BCUC IR1 5.2, UPC_{peak} values are refreshed annually, providing a regular check on the current state of peak demand requirements. This includes potential future impacts resulting from current efficiency changes that may influence the UPC_{peak}. As a result, the UPC_{peak} of new customers is reflected, to a degree, in the yearly analysis. FEI recognizes that the UPC_{peak} of new customers is likely to be slightly lower than the current average. Regardless, in any given year the net impact of new customer additions on the total peak demand determined from UPC_{peak} is a very small portion of the total peak demand for that year. The impact of a small fraction of that added peak demand being lower because of a smaller UPC_{peak} is even less. The net impact on peak demand may grow larger later in the forecast, but the near-term impacts which would affect the timing of projects to address impending capacity shortfalls is immaterial. As a result, FEI applies the same UPC_{peak} values to represent both existing and new customers in the system.

Page 4 of the BC Office of Housing and Construction document titled "Provincial Policy: Local Government Implementation of the BC Energy Step Code"[3] states:

> The BC Energy Step Code is a voluntary roadmap that establishes progressive performance targets (i.e., steps) that support market transformation from the current energy-efficiency requirements in the BC Building Code to net zero energy ready buildings. It establishes a set of incremental performance steps for new buildings that aims to communicate the future intent of the Building Code and improve consistency in building requirements across British Columbia (B.C.) to transition to net zero energy ready buildings by 2032. It is a voluntary tool local governments across B.C. can use to encourage—or require—the construction of more energy-efficient buildings in their communities, and do so in a consistent, predictable way.

5.5 Please discuss whether FEI assumes the number of new customer accounts to be directly correlated with new buildings.

Response:

FEI's gross customer additions have a correlation to new building construction and for forecasting gross customer additions, FEI assumes that a percentage of new buildings will be new gas customers. However, FEI's customer account forecast and the forecast used to determine the peak demand is a net customer additions forecast, therefore FEI does not assume net customer accounts are directly correlated with new buildings. Net customer additions are impacted by customers that leave the system for a variety of reasons.

5.6 Please provide any analysis FEI has undertaken with respect to the actions adopted by local governments in the ITS service area to implement the BC Energy Step Code, such as mandatory building requirements.

Response:

The BC Energy step code has been implemented by local governments in the largest urban areas served by the ITS. The BC Energy Step Code was implemented in 2019 in the City of Kelowna and the City of Penticton, and in the City of Vernon in 2020. FEI is not aware of any other mandatory buildings requirements adopted by these municipalities.

---

[3] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/construction-industry/building-codes-and-standards/guides/baguide_c2_sc_april2017.pdf.

5.7 Please discuss the extent to which the BC Building Code and implementation of the Energy Step Code in BC represents a known and measurable impact upon peak load forecasting for new customers in the forecast period, particularly in municipalities who have adopted mandatory approaches to implementing the Energy Step Code.

Response:

FEI has not observed any measurable impact (i.e., decrease in peak demand) for new customers due to the adoption of the BC Energy Step Code by the three larger municipalities identified in the response to BCUC IR1 5.6. Rather, the population of the Okanagan region has continued to increase and this population growth has led to a corresponding increase in customer demand. Furthermore, increasing industrial load, including new CNG fuelling stations, greenhouse expansions and winery operations, along with other industrial customers on the system, has also contributed to the increase in demand. FEI also notes that industrial customers are not impacted by the implementation of the BC Energy Step Code, as it is applicable only to new residential and commercial construction.

6.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, p. 23

Exhibit B-1-2-1, Appendix L-3, "ITS Inc. Acct Growth" tab; "ITS Peak Day Demand" tab

Peak Demand Forecasting by Customer Class

On page 23 of the Updated Application, FEI states:

> To maintain consistency with FEI's rate setting forecast, FEI "trues up" each year of the more granular BC Stats/LHA forecast to the regional rate-setting forecast. For residential customers, the rate-setting forecast uses the single family/multi-family growth rates from the Conference Board of Canada (CBOC) forecast. The CBOC forecast is applied province-wide and does not provide the regional granularity of the BC Stats/LHA method. The commercial rate-setting forecast uses a three-year average of customer additions. To "true up" the forecast, FEI factors the municipal forecasts up or down so that the aggregate sum by region matches the CBOC method, but the differences by LHA remain. This has the advantage of maintaining consistency with FEI's rate-setting aggregate forecast, while also providing a granular forecast that is reflective of the growth patterns forecast by the BC Stats/LHA method.

6.1 Please clarify the difference (if any) between the terms "household formation" as defined by BC Stats/LHA and "housing starts" as defined by CBOC.

Response:

The BC Stats definition of a household can be found in footnote 11 on page 23 of the Updated Application and is repeated here for convenience:

> BC Stats uses the Statistics Canada definition of a household as follows: "Household refers to a person or group of persons who occupy the same dwelling and do not have a usual place of residence elsewhere in Canada or abroad. The dwelling may be either a collective dwelling or a private dwelling. The household may consist of a family group such as a census family, of two or more families sharing a dwelling, of a group of unrelated persons or of a person living alone. Household members who are temporarily absent on reference day are considered part of their usual household. A household formation is the formation of a new household."

The Conference Board of Canada (CBOC) defines a housing start as "The number of residential units for which construction has begun."

FEI uses the growth rate of household formations (not the household formations themselves) to disaggregate regional customer additions appropriately to municipalities based on the household formation growth rate for that municipality. Municipalities that have higher household formation growth rates are assigned a larger portion of the regional customer additions.

6.2 Please explain whether the trueing-up of the residential forecast (using the CBOC forecast results) in higher or lower growth rates for the ITS than the BC Stats/LHA forecast.

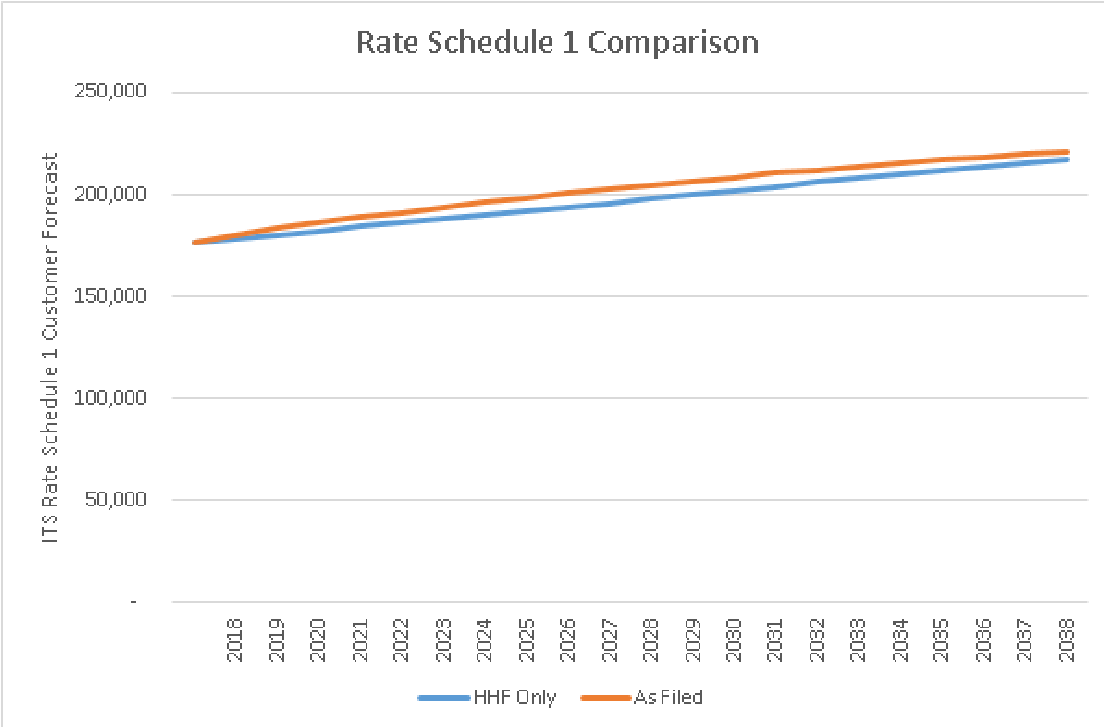
Response:

For clarity, FEI assumes the question was intended to place the closing bracket after "forecast" as shown:

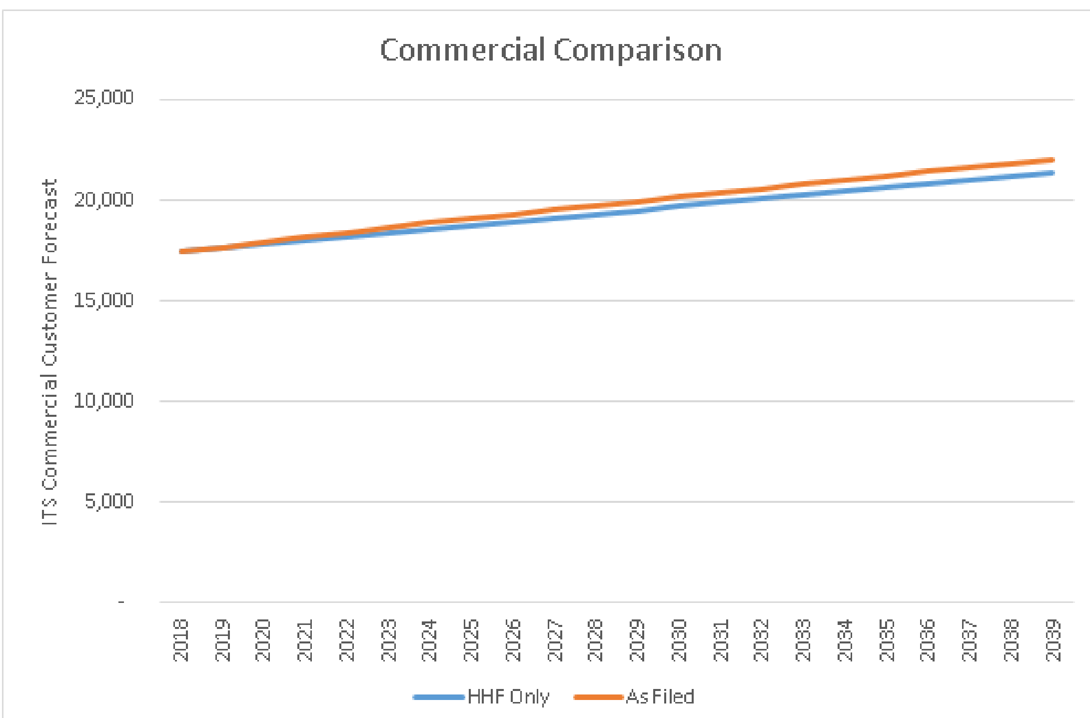
> Please explain whether the trueing-up of the residential forecast (using the CBOC forecast) results in higher or lower growth rates for the ITS than the BC Stats/LHA forecast.

Year-over-year customer growth rates from a forecast developed using either the CBOC method for residential customers or the three-year average method for commercial customers would be higher compared to a similar forecast prepared using only the BC Stats/LHA growth rates.

The following chart for residential customers shows that the forecast developed using only the BC Stats household formations growth rates for the ITS communities is slightly lower (1.48 percent) than the filed forecast. 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.



The following chart for commercial customers shows that a forecast developed using only the BC Stats household formations growth rate for the ITS communities is lower (2.96 percent) than the filed forecast.



FEI notes that HHF forecast is a way to disaggregate the regional customer additions forecasts developed by the CBOC and three year average methods into municipalities in a way that represents the expected growth in those municipalities. The ITS spans both the Inland and Columbia regions and the disaggregation of growth further allows for combining the municipalities that are connected to the ITS.

6.3 Please explain why consistency is needed with the rate-setting forecast for the purposes of capacity planning.

Response:

FEI's load forecasts are used for a number of different applications and regulatory filings in which the forecast periods may overlap. 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.

6.3.1 Please identify any key differences in the objectives of forecasting for rate-setting and forecasting for capacity planning.

Response:

There are no differences in the objectives of forecasting customer accounts for rate-setting and forecasting for capacity planning. The sole objective of the customer forecast process is to develop a single, accurate forecast that can be aggregated and disaggregated with consistency and reasonableness.

For the purposes of capacity planning, FEI considers a longer forecast period up to 20 years and considers the future impact of the peak demand on the system. Peak demand occurs over a short period of hours or days. Capacity planning takes a longer forecast view in order to identify and plan for upgrade projects that may take many years to construct. In addition, capacity planning is concerned with where on the system peak demand occurs and so the more granular information from the BC Stat/LHA forecasts meets that objective.

For the purposes of rate setting, a shorter forecast period is considered. The rate setting demand forecast considers regional annual demand and is not impacted by peak demand or the locality of the demand on the system.

6.4 Please explain why a three-year average of customer additions is used to true-up the forecast for commercial customers.

Response:

FEI clarifies that the "three-year average of customer additions" referenced on page 23 of the Updated Application was intended to refer to "the three year average of commercial customer additions". A revised paragraph is provided below. The underlined words have been added for clarity.

> The commercial rate-setting forecast uses a three-year average of commercial customer additions. To "true up" the forecast, FEI factors the municipal forecasts up or down so that the aggregate sum by region matches the CBOC method (for residential customers), or the three year average method (for commercial customers), but the differences by LHA remain.

A three-year average of commercial customers additions is used because, as shown in Appendix B2 of its 2020-2024 Multi-Year Rate Plan (MRP) Application, FEI's analysis showed that the existing three-year average method used for forecasting commercial customer additions was superior to the alternative methods tested. FEI did not recommend any change to that component of the forecast. Appendix B2 to the MRP Application can be found online at the following link: https://www.bcuc.com/Documents/Proceedings/2019/DOC_53565_B-1-1-FortisBC-2020-2024-Multi-YearRatePlan-Appendices.pdf

6.4.1 Please explain whether the trueing-up of the commercial customer forecast (using the three year average of customer additions) results in higher or lower growth rates for the ITS than the BC Stats/LHA forecast.

Response:

Please refer to the response to BCUC IR1 6.2.

An excerpt of the "ITS Inc. Acct Growth" tab of Appendix L-3 to Exhibit B-1-2-1 is provided below, showing the growth rate for Rate Schedule 3 (RS 3) customers on the Total ITS System:

2018 YE Accounts	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
628	9.1%	8.5%	8.1%	7.7%	7.1%	6.7%	1.1%	1.1%	1.0%	1.1%	1.0%

6.5 Please explain why the forecasted growth rate for RS 3 customers is higher than other customer classes in the period 2019 to 2024.

6.5.1 Please explain the reason for the significant drop in the forecasted growth rate between 2024 and 2025.

Response:

The forecast RS 3 customer growth rate is higher than the other rate schedules from 2019-2024 due to the unusually high number of RS 3 customers that were added to the system in 2018.

As shown in Figure 1 below:

1. Prior to 2017 and 2018 RS 3 customer additions were low.
2. In 2017 and 2018 RS 3 customer additions increased sharply.
    a. The red rectangle indicates the data used to develop the RS 3 customer additions forecast (using a three year average).

Figure 1: RS 3 Actual Customer Additions

As show in Figure 2 below:

1. Line segment 1 shows the actual RS 3 customers.
2. Line segment 2 shows the result of the commercial customer forecast from 2019 to 2024.
3. Line segment 3 shows the long-term result of continuing to add the forecast annual additions each year, through 2039. This forecast was considered unreasonable because:

a. There was no apparent cause for the customer increase in 2018.

b. Based on Grubbs Outlier test[4] the 2018 value of 117 customer additions was an outlier.

4. Line segment 4 shows the adjustment FEI made to the forecast in 2025.

As a result of the adjustment the annual RS 3 customer growth rate from 2025 through 2039 is now similar to the other rate schedules as per the “ITS Inc. Acct Growth” tab in Appendix L-3 to the Updated Application.

Figure 2: RS 3 Customer Forecast

In the “ITS Peak Day Demand” tab of Appendix L-3 to Exhibit B-1-2-1, Row 151 shows a forecast peak industrial demand of 62.23 TJ/d for the forecast period.

6.6 Please confirm which rate schedules comprise the “industrial demand.”

<u>Response:</u>

The following rate schedules are included in the industrial demand:

- Rate Schedule 5
- Rate Schedule 6

---

4 https://www.graphpad.com/quickcalcs/grubbs2/.

- Rate Schedule 23
- Rate Schedule 25
- Rate Schedule 22A and 22B (contractual firm quantity only)

Rate Schedules 22A and 22B have a large component of their demand that is interruptible service. Only a portion of the demand is contracted as a firm delivery requirement and only that portion is included in peak demand forecast.

6.7 Please confirm, or explain otherwise, the industrial demand figure of 62.23 TJ/d represents firm demand from industrial customers only.

6.7.1 If interruptible demand is included, please provide a breakdown of the 62.23 TJ/d figure by firm and interruptible demand.

Response:

Confirmed. As indicated in the response to BCUC IR1 6.6, only firm quantities for industrial customers are included in the peak demand forecast.

7.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, p. 21

Industrial demand

On page 21 of the Updated Application, FEI states:

> Maximum Demand from Firm Industrial Customers: For firm industrial customers with available hourly consumption data, FEI determines the UPCpeak for each customer directly from the hourly data. The peak day demand is determined based on the maximum demand observed in the hourly consumption of the customer and assumes that consumption would be sustained over a day. The peak day demand is therefore equivalent to a peak day flow. If an industrial customer has made a contractual commitment to increase their future firm load, this incremental load is included in the peak day demand forecast. Otherwise, FEI does not include any change in industrial customer numbers or demand due to the uncertainty associated with the location and magnitude of consumption needs of future customers in industrial rate schedules.

7.1 Please explain why FEI does not use daily consumption data to determine the UPCpeak for firm industrial customers.

<u>Response:</u>

FEI builds system-wide peak demand based on the loads originating from within the distribution system. The vast majority of industrial customers served by the ITS are located within distribution systems operating at a maximum pressure of 420 kPa. These distribution systems are designed on a peak hour basis as they have no capacity or useable line pack to accommodate hourly load swings. 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.

7.2 Please discuss whether the assumption that an industrial customer's maximum hourly demand is sustained over a day is supported by metered data.

7.2.1 If not, please explain why FEI makes this assumption.

7.2.2 Please provide the total hourly load profile of FEI's firm industrial customers in the ITS in the peak day observed in the last three years.

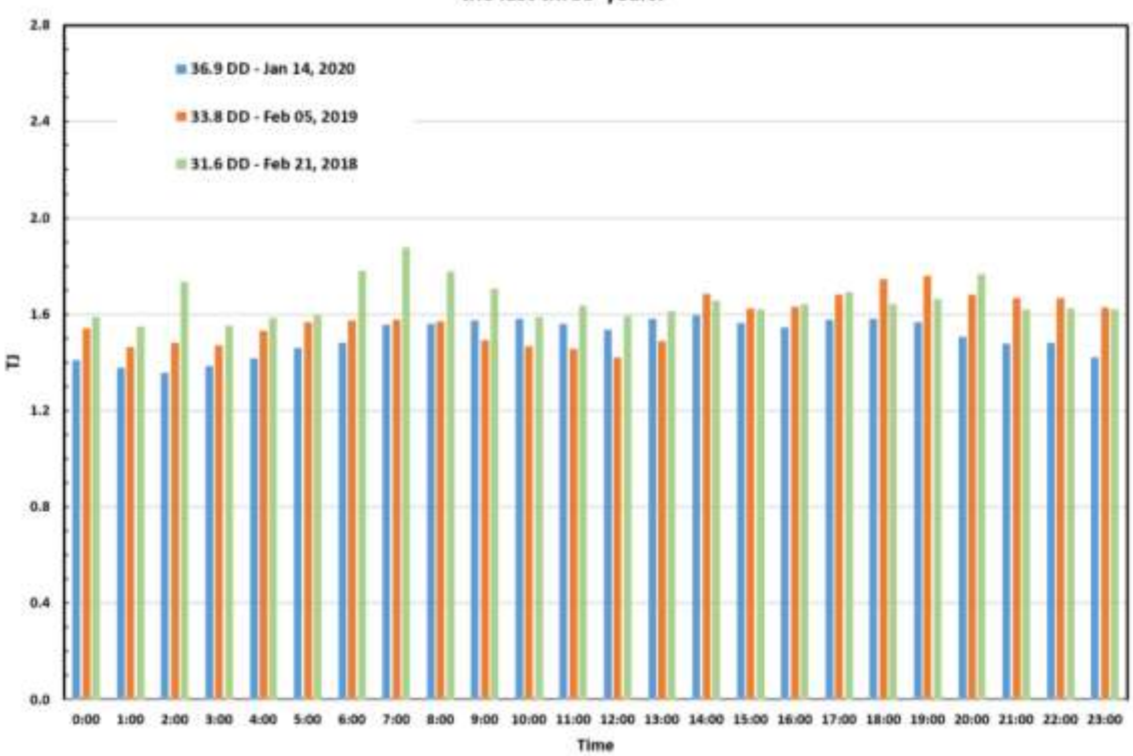
Response:

FEI provides the figure below that shows the total hourly load profile of firm industrial customers on the system for the coldest days in 2018, 2019, and 2020 with flow sustained through the day.

The data indicates a relatively steady cumulative industrial firm demand, with flow varying through the day but not significantly. The time of day when the peak occurs is also variable, with the maximum flows aligned at different points in the day.

FEI also notes that the industrial demand on February 21, 2018 was higher than on January 14, 2020, a day that was 5.3 degrees colder. This indicates the industrial demand is not well correlated to temperature, and colder days could also experience much higher industrial demand than that represented in the figure. As a result of this uncertainty around when, and how sustained, the peak industrial flow will be on any given day, FEI models system capacity to support a sustained maximum industrial demand equal to the highest hourly value observed for each customer.

Figure 1. Total hourly load profile of firm industrial customers in the peak day observed in the last three years.



7.3 Please discuss whether FEI considers further capacity upgrades would likely be required in the forecast period to accommodate any additional firm industrial customers.

Response:

FEI is unable to determine with any certainty if or when further capacity upgrades might be required to accommodate any additional firm industrial customers. Such determination would ultimately be driven by factors such as the future change in demand of existing industrial customers as their demand evolves, and the location and demand requirements of future industrial customers. FEI considers such factors to be speculative and therefore are not included in the forecast peak demand for the OCU Project. If a new firm industrial customer is significant enough to drive a major upgrade of the ITS on its own to support the customer connection, that would need to be considered and managed and ultimately approved based on the specific requirements of the proposed customer.

8.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, p. 22

1 in 20 Weather Event

On page 22 of the Updated Application, FEI states:

> FEI's DDD [Design Degree Day] temperature for any system operating within a region is the coldest day that is statistically likely to occur only once in any given 20 year period. In determining the DDD value, FEI uses an extreme value statistical method called the Gumbel Method of Moments. This method returns the expected extreme value for a given historical data set based on a specified return period. FEI uses a 1 in 20 return period on a data set that represents the coldest recorded daily mean temperature at the region's weather station each winter over a 60 year period.

> The DDD temperature values for weather zones in the ITS range from a 46.7 Degree Day (DD) 16 (corresponding to minus 28.7°C mean daily temperature) in the Thompson region, to a 43.9 DD (corresponding to minus 25.7°C mean daily temperature) in the North and Central Okanagan region, to a 39.1 DD (corresponding to minus 21.7°C mean daily temperature) in the South Okanagan region. The regional DDD values are based on a 60 year weather history as reported by Environment Canada at the Kamloops Airport, Kelowna International Airport, and Penticton Regional Airport weather stations, respectively.

8.1 Please compare the DDD values for the Thompson region, North and Central Okanagan region and South Okanagan region against the coldest day observed in the last 20 years.

<u>Response:</u>

The following table presents the requested weather information for the three regions.

Coldest Days Observed since January 1, 2001

Index Weather Station	Region	Design Degree Day (DDD)	Coldest Day 2001-2021 (DD)	Date of Occurrence
Kamloops (YKA)	Thompson	46.7	42.4	14-Jan-05
Kelowna (YLW)	North/Central Okanagan	43.9	42.2	20-Dec-08
Penticton (YYF)	South Okanagan	39.1	35.7	20-Dec-08

8.1.1 Please outline the number of days in the last 60 years where the observed mean daily temperature was colder than the DDD, and the dates of these occurrences.

Response:

The table below provides the requested weather history for the region.

Days Observed in 60 Year Weather History Exceeding Design Degree Day

Index Weather Station	Region	Design Degree Day (DDD)	Coldest Days (DD)	Date of Occurrence
Kamloops (YKA)	Thompson	46.7	47.9	28-Dec-68
			50.9	29-Dec-68
			47.4	30-Dec-68
			47	22-Jan-69
			47.3	28-Jan-69
			47.8	29-Jan-69
Kelowna (YLW)	North/Central Okanagan	43.9	46.9	29-Dec-68
			46.3	30-Dec-68
Penticton (YYF)	South Okanagan	39.1	40.5	16-Dec-64
			42.4	28-Dec-68
			42.3	29-Dec-68
			41.1	30-Dec-68

8.2 Please explain whether the Gumbel Method of Moments places greater weight on observed temperatures in more recent years.

Response:

No, the Gumbel extreme value analysis does not place greater weight on values based on when they occur. A set of extreme values is an input to the analysis; for FEI, this is the coldest day to occur in each of 60 years. There is no input into the statistical method to reflect or measure how the data point is related to other data points in the data set along a timeline, i.e. if one data point occurs sooner or later than another.

8.2.1 Please explain why a 60 year data set is used instead of the most recent 20 year period.

Response:

FEI has two main objectives that are met by using a 60 year data set. The first is to determine a sufficiently infrequent weather event to design the gas system to ensure reliability and security of supply can be met under the associated high demand forecast to occur during such an event. The second is that the design event is a stable and reproducible target for designing the system and doesn't change from year to year.

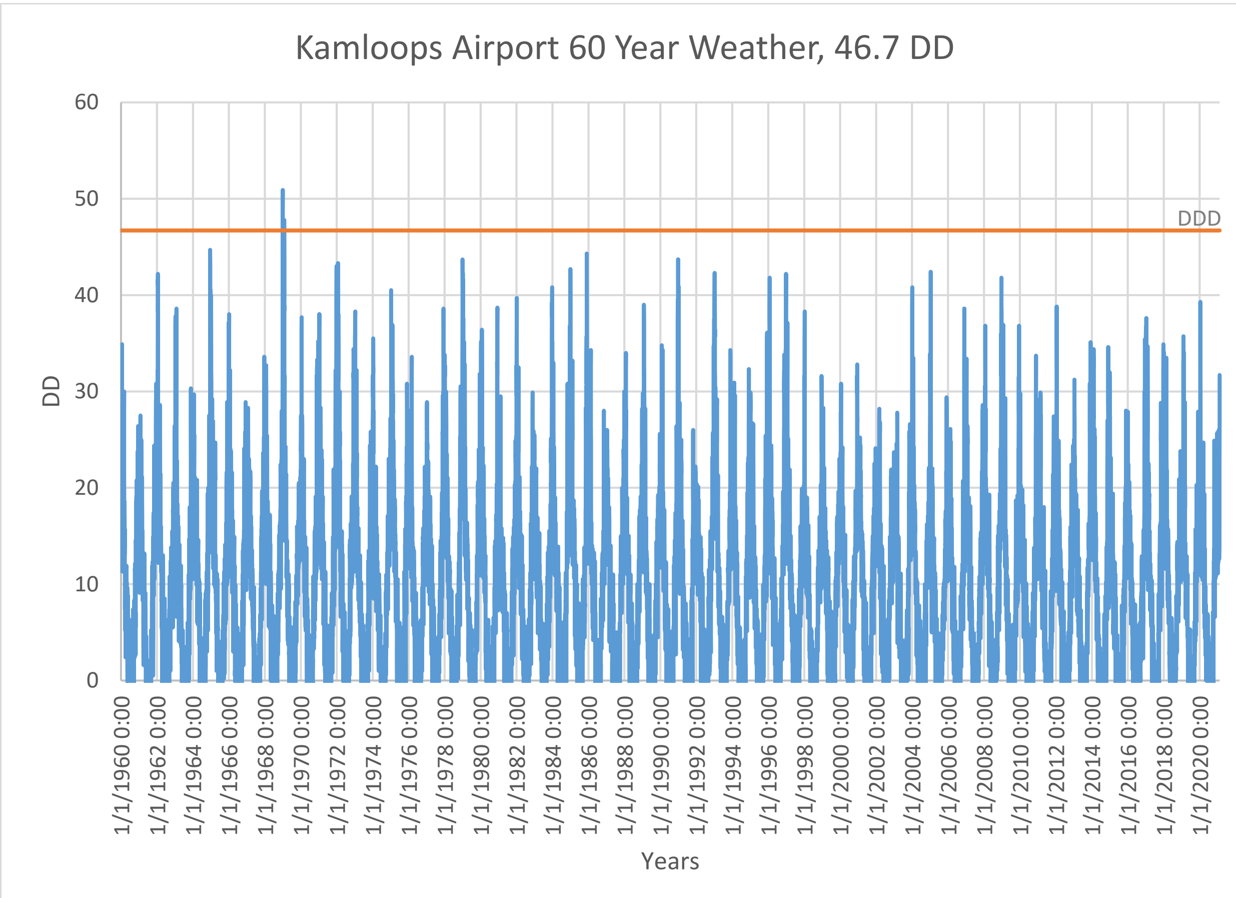
FEI believes that an event that is likely to occur only once in a 20 year period only meets the first objective. This is why FEI does not design to a return period of 1 in 15 year or 1 in 10 years. Where the impact of loss of supply due to insufficient capacity can result in customer outages than can extend for days or more in extremely cold weather, to meet a high level of reliability for gas distribution and transmission systems FEI uses a 1 in 20 year return period.

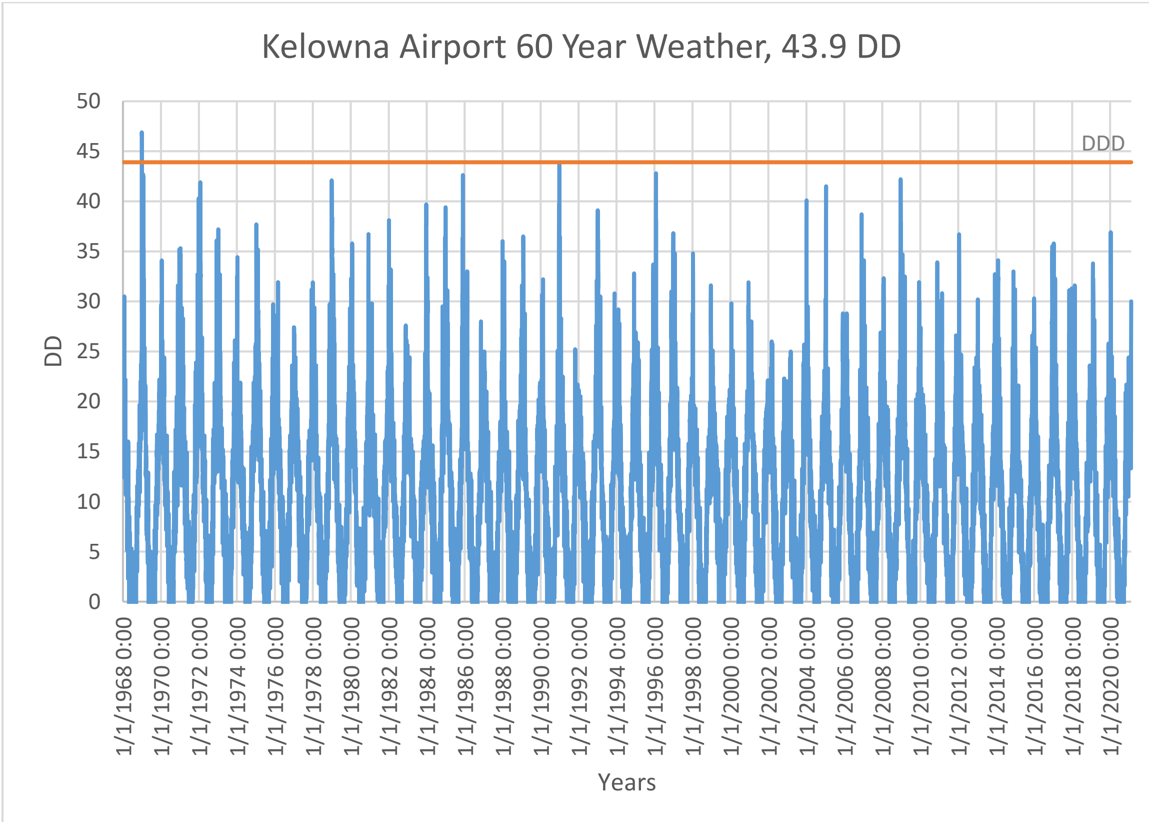
Regarding the second objective, as a vital design parameter, it is important that the system design temperature produce a stable and reproducible result which does not vary dramatically over time. This ensures that projects have a clearly defined objective to meet. Using a data set of 20 values to calculate the likely extreme temperature in a future 20 year period is possible. However, the result may vary significantly when it is recalculated in subsequent years, particularly if the data set drops a winter of very cold temperatures and replaces it with a very warm year. A variation such as that just described would have less impact on the statistical result if the data set is larger and there is less influence from year to year changes. FEI uses the result of the Gumbel Method of Moments to provide a consistent design degree day (DDD) temperature to determine peak demand and hence system capacity. To provide consistency, FEI does not currently recalculate the DDD more than once per decade. Using a smaller sample of 20 years would require FEI to recalculate and change the DDD much more frequently. Given the volatility of extreme weather, FEI considers that a 60 year data set reflects trends in weather in a more stable fashion.

8.3 Please discuss at a high level any observed trends in the frequency and severity of extreme cold events in the last 60 years.

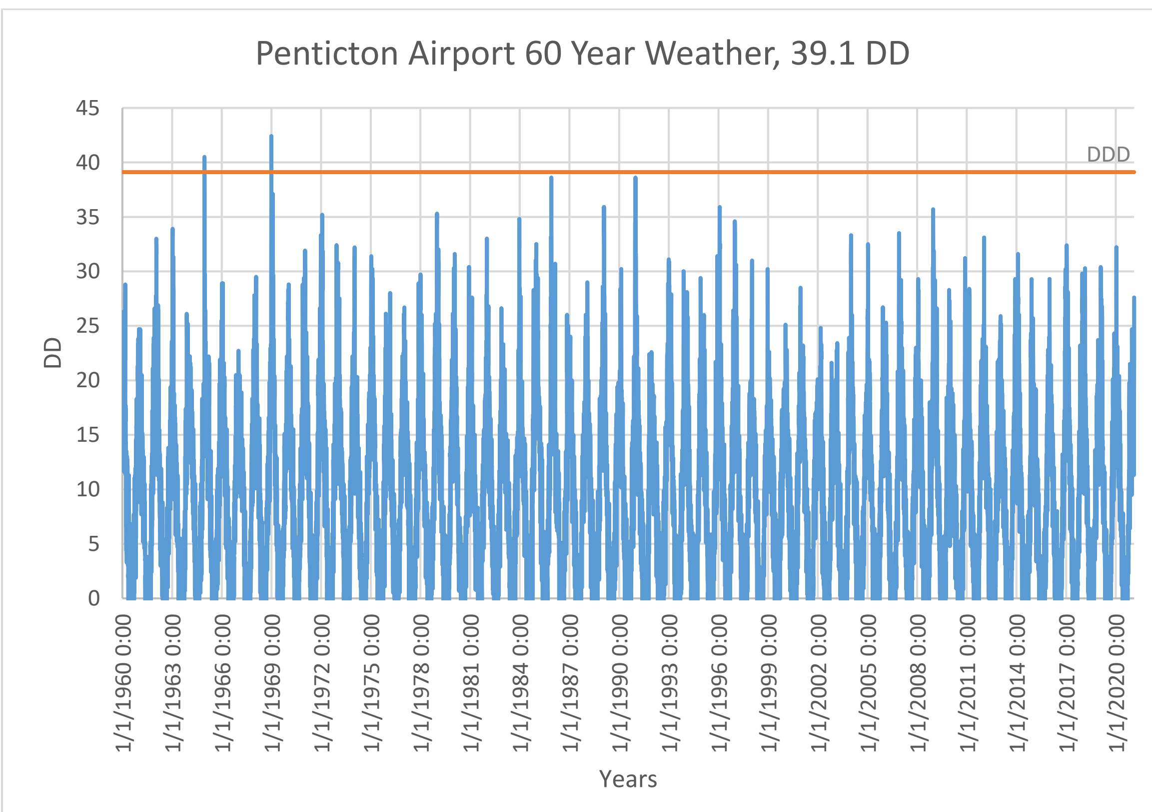
Response:

The three figures below present the recorded weather at each weather station listed in the preamble above. The weather data for each region over the past 60 years has exhibited a variation in extreme values with the winter of 1968-69 being the coldest winter in the history and winter of 1964-65 the next most extreme. The Kelowna Airport data only extends to 1968 so does not comprise a full 60 year history, however it does contain the extreme winter of 1968-69 when the DDD was exceeded. Since then, the most recent extremes occurred in December 1990 with temperatures within 0.2°C of reaching the DDD and in 2008 with temperatures coming within 1.8°C of reaching the DDD. All three regional weather records show a wide distribution of winter extremes over their history. The most extreme event in all regions is within the first 10 years of the data history so those values will be removed from the extreme value analysis in the next 5-10 years. The magnitude of future peak winter low temperatures that will replace the extreme values recorded in the 1960s will determine whether the DDD will increase, decrease or stay constant in these regions when recalculated in the future.





Kelowna Airport 60 Year Weather, 43.9 DD
DDD
DD
Years



Penticton Airport 60 Year Weather, 39.1 DD
DDD
DD
Years

8.4 Please explain whether FEI makes any adjustments to the DDD due to climate change, for example based on observed or expected trends in the frequency and severity of extreme cold events.

Response:

FEI's peak demand forecast does not directly consider the potential impact of climate change on the DDD. FEI is not aware of a reliable method to forecast future changes in extreme weather either in severity or frequency (especially in the cold temperatures which set FEI's peak demand).

However, FEI does apply trends in recent weather history (that may reflect climate change impacts) by periodically re-adjusting the DDD temperature used to estimate peak demand. FEI last updated the DDD for each of the 22 weather zones in its operating territory in 2017. These updates examined the weather history in each weather zone over the preceding 60 years. The last update resulted in a warming in the DDD temperature in most weather zones. For example, in the case of the north and central Okanagan, the DDD changed from a 45.0 degree day to a 43.9 degree day. This represented a warming of 1.1°C in the design temperature. The Thompson region DDD warmed by 2.2°C and the South Okanagan by 0.9°C. This results in lower peak demand estimates for customers in these regions than would have been calculated using the DDD values in use prior to 2017.

9.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, pp. 25, 51
Class Locations

On page 25 of the Updated Application, FEI states:

> The ITS serving the Thompson Okanagan region has several regions where pressure is controlled below the original MOP [maximum operating pressure] to ensure pipeline safety factors associated with CSA Z662 class locations requirements. These pressure-controlled regions are identified in Table 3-1 above, with the segments most relevant to the OCU Project listed in rows 2 to 5.

On page 51 of the Updated Application, FEI states:

> The class location of a pipeline is related to the population density in the surrounding area. As population in an area increases, the class location can change, and a pipeline operator must take action to ensure the pipeline meets the requirements of the new class location. This can mean reducing MOP or modifying the pipeline.

9.1 Please explain whether FEI anticipates any class location changes will be required to FEI's pipelines in the ITS during the forecast period as a result of the expected population growth discussed in section 3.3 of the Updated Application.

Response:

At the present time, FEI is not aware of any potential class location changes along FEI's ITS pipelines during the forecast period as a result of the expected population growth.

In accordance with the requirements of CSA Z662:19, FEI is required to assess its pipelines on a regular basis to determine if class locations changes have occurred. Although FEI expects population growth, it is difficult to predict exactly where this growth will be located and whether it will be immediately adjacent to the pipelines in the ITS. As a result it is difficult to anticipate if and where class location changes might occur and whether there will be an impact on the pipelines.

B. SHORT TERM MITIGATION MEASURES

10.0 Reference: SHORT TERM MITIGATION MEASURES

Exhibit B-1-2, pp. 34, 35, 37

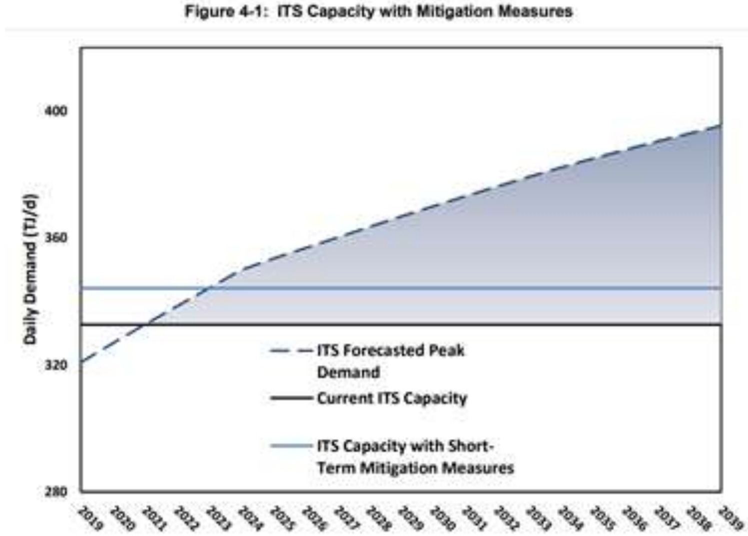
Description of Short Term Mitigation Measures

In sections 4.2.1 to 4.2.4 on pages 34 to 35 of the Updated Application, FEI describes the following short term mitigation measures: contractual minimum pressure increase, temporary load shifting, station modifications, and additional mitigation measures.

With respect to additional mitigation measures, FEI states, “In addition, throughout the period prior to completion of the OCU Project, FEI will manage load additions within system capacity limitations, and identify and manage existing customer loads under peak conditions.”

Figure 4-1 on page 37 shows the ITS capacity with the short term mitigation measures:

Figure 4-1: ITS Capacity with Mitigation Measures



10.1 For each of the four short term mitigation measures FEI is planning to undertake, please explain the following:

- Whether there are any reliability concerns with respect to the measure’s ability to provide dependable capacity during a peak demand event (assuming overall system capacity was sufficient to meet demand);
- The extent to which potential exists for increased capacity by further expansion of the measure at the location(s) described and/or elsewhere on the ITS, and any implications of expanding the measure;
- The potential longevity of the measure as a reliable capacity solution (assuming overall system capacity was sufficient to meet demand).

Response:

Following are the reliability, expansion, and longevity concerns for each of the four short-term mitigation measures.

1. Contractual Minimum Pressure Increase

a) Reliability Concerns: An ongoing minimum pressure increase was not represented in the short-term mitigation measures which formed the basis for Figure 4-1 as FEI cannot depend on the additional 50 psig of pressure at Savona. FEI has a verbal understanding that Enbridge will attempt to maintain a minimum 650 pisg pressure at the custody transfer point at Savona; however, no firm contractual obligation exists. For this reason, FEI cannot consider this measure reliable. However, when available, this increased pressure will improve the effectiveness of the other short term mitigation measures.

b) Expansion Potential: FEI does not have the ability to increase capacity reliably or permanently by maintaining or expanding this measure as it is dependent on Enbridge's system capacity, which is not within FEI's control.

c) Longevity: FEI cannot guarantee that this measure will be available over the long-term.

2. Temporary Load Shifting

a) Reliability Concerns: Temporary load shifting is a viable method of reducing the flow through the Polson and Kelowna #1 Gate Stations and can be accomplished by adjusting the station set points in each system in advance of winter each year. This approach shifts the flow to other stations serving the system that do not have the same inlet pressure requirements as the gate stations serving IP systems. As discussed in Section 4.2.2 of the Updated Application, this shift reduces the flow and the overall pressure drop in the transmission laterals supplying these stations and thereby improves the inlet pressure at these stations, but otherwise does not impact reliability.

b) Expansion Potential: This approach is limited by the ability of the distribution system to deliver the offset load to the customers who would otherwise be served through the Polson Gate or Kelowna #1 Gate Stations. These gate stations cannot be underset more than what is currently being considered as this would reduce pressures in the downstream IP and DP systems such that minimum capacity requirements in these systems would no longer be met. There are no other systems available to further offload the Kelowna #1 Gate Station or the Polson IP system.

c) Longevity: The acceptance of very low inlet pressures through Polson and Kelowna #1 Gate Stations means a decreased capacity in the downstream DP and IP systems. FEI's modeling indicates that with planned station upgrades in these systems, acceptable capacity can be maintained only through the winter of 2021/2022. As demand on these systems continues to increase, full flow through these stations is likely to be required. Thus this measure can only be maintained temporarily.

3. Station Modifications

Upgrades to district stations to improve capacity will provide a reliable increase in capacity, which will be maintained into the future. FEI does not have reliability concerns associated with this portion of this measure, but there is limited potential to expand it further. The following responses will focus on installation of full station bypasses.

a) Reliability Concerns: Full station bypasses which will be installed at Polson and Kelowna #1 Gate Stations will be manually operated during peak winter conditions to bypass station equipment and eliminate the associated pressure drop, thereby improving inlet pressure downstream of each station. Manual operation of bypass valves which directly interconnect the transmission and intermediate pressure systems will be performed by qualified and trained FEI operations personnel; however, this will involve logistical challenges and risk. While FEI is confident the measure can be successfully executed for short periods, significant local operational effort and oversight will be required to ensure safe operation of the system.

b) Expansion Potential: There is no potential to expand this measure. FEI will already be fully bypassing stations, allowing gas from FEI's transmission system to enter downstream systems with no pressure drop.

c) Longevity: FEI will not maintain this measure following installation of necessary pipeline infrastructure as the OCU Project will improve inlet pressures at the stations such that it would no longer be necessary to bypass the stations.

4. Additional Mitigation Measures

Please refer to the response to BCUC IR1 2.6.1 for the issues with respect to customer curtailment and load management.

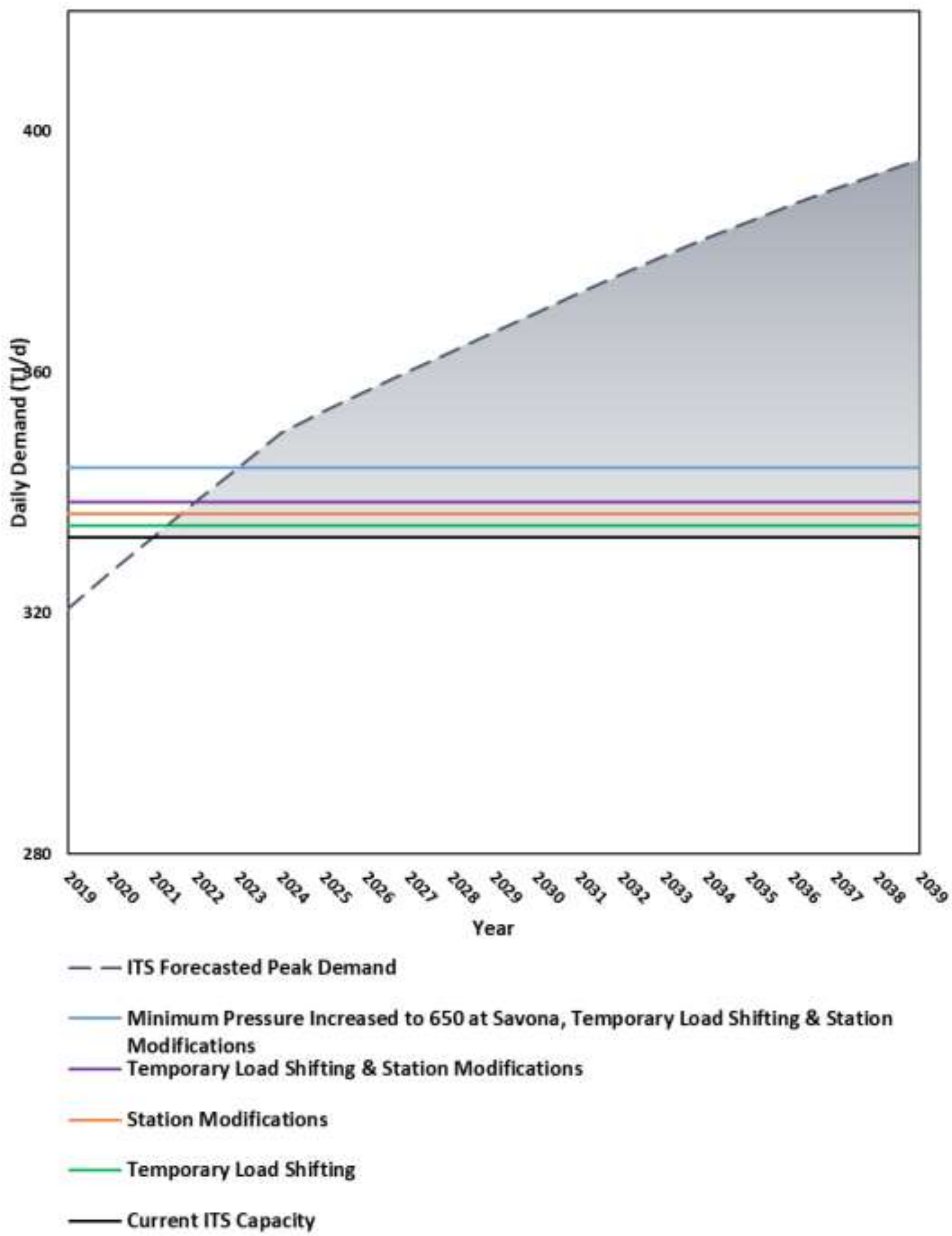
In summary, the pressure decay illustrated in the response to BCUC IR1 2.5 shows the overall longevity of the described mitigation measures. With the mitigation measures, the pressure decay becomes unacceptable by the winter of 2023-2024 without the OCU Project in service.

10.2 Please provide a breakdown of the estimated capacity increases shown in Figure 4-1 by measure.

Response:

The following figure provides a breakdown of the estimated contribution of each of the mitigation measures. Please note that the blue line, which shows the combined impact of all proposed short-term mitigation measures, was modeled with a minimum inlet pressure of 650 psig to FEI's system at Savona (as indicated in the figure legend). This is not a firm contractual increase, but rather represents a working agreement between FEI and Enbridge. All other capacity lines were modeled with an inlet pressure of 600 psig to FEI's system at Savona.

Breakdown of Short-Term Mitigation Measures



10.3 Please further explain how FEI intends to "identify and manage existing customer loads under peak conditions."

Response:

As discussed in the response to BCUC IR1 2.6.1, FEI has no means of conducting a mass curtailment of customers in a local system. To be effective, the target of any load curtailment would focus on large volume customers where the curtailment effect could be more easily quantified and managed. FEI's internal industrial marketing group is aware of the potential limitation on ITS capacity. This group works with existing and potential industrial customers who rely on FEI's natural gas service. Until the OCU Project is completed, this group will inform new customers, or existing customers adding load, that FEI may not have the capacity to serve them on a firm basis until completion of the Project. In some cases, customers will accept an interruptible rate schedule until the OCU Project is complete at which time FEI can provide firm service. In other cases, FEI will not be able to accommodate the customer connection or expansion.

11.0 Reference: SHORT TERM MITIGATION MEASURES

Exhibit B-1-2, pp. 35, 36

Compressed Natural Gas

On pages 35 to 36 of the Updated Application, FEI states:

> To mitigate the forecast capacity shortfall, 1 to 2 large truckloads of CNG [compressed natural gas] per hour (up to 4 – 6 truckloads per day) would be required during a peak demand event by the winter of 2022/2023. With growing demand in the region, the capacity shortfall and corresponding amount of CNG or LNG [liquefied natural gas] required will increase over time. CNG trucks would be required to travel from a filling point outside of the central Okanagan, where the system has a sufficient gas surplus to allow trucks to fill, to an effective injection point in the central Okanagan. LNG trucks would be supplied from FEI's Tilbury LNG facility in Delta, approximately 400 km from the shortfall region. This CNG/LNG truck traffic would be required during a peak demand event, which corresponds to the most severe winter weather in B.C.
>
> Transporting fuel by truck during severe winter weather is a less cost effective and reliable method of gas transportation than appropriate and adequate pipeline infrastructure. The reliability concerns could be mitigated through staging of sufficient additional trucks, but this would come at an increased cost. CNG and LNG supplementation would not provide a lasting improvement to FEI's system, as CNG/LNG supplementation is not a viable long-term solution to the capacity shortfall in the Okanagan and will not decrease the cost associated with this required pipeline installation.

11.1 Please provide any analysis that FEI has performed to assess the potential costs of CNG and/or LNG against the potential benefits of deferring the OCU Project (for example, by one to five years).

<u>Response:</u>

A detailed cost/benefit analysis was not completed as FEI does not consider CNG and/or LNG supplementation to be a practical or appropriate means of addressing the forecast ongoing capacity shortfall on the ITS in order to defer the OCU Project. While CNG/LNG supplementation are useful as an emergency response tool, the sections below discuss in qualitative terms the shortcomings of CNG/LNG as a solution to defer major capacity upgrades.

CNG/LNG Trucking Has Lower Reliability and Potentially Higher Safety Risks than a Pipeline

Pipelines are a more reliable method of natural gas transportation than CNG/LNG trucking. Trucking introduces the risk of service disruptions due to heavy traffic or accidents, driver error, road closures due to severe winter weather, and/or truck breakdowns. There is also added risk associated with trucking CNG/LNG when compared with pipeline transport of natural gas; traffic accidents involving CNG/LNG trucks may present a risks to drivers and to the public in the surrounding area due to the potential of a product release. As the number of trucks required to maintain capacity increases, the associated risk increases as well. The response to BCUC IR1 11.4 provides more detail regarding the reliability concerns with this solution.

CNG/LNG Implementation Is Logistically Difficult

The number of daily and hourly truckloads required to maintain capacity during peak demand quickly becomes logistically infeasible. By the winter of 2024-2025, up to 36 truckloads of CNG would likely be required on a peak day, a number which FEI does not consider feasible in this scenario. In FEI's previous experience using CNG injection (please refer to the response to BCUC IR1 11.4.1) it can take 1.5 to 2 hours to fill each truck, and 1 to 2 hours to empty each truck at the injection point. While it is possible to fill and to empty multiple trucks at a time, this increases the space and personnel requirements at the compression and decompression sites. This in turn increases the logistical difficulty and the demand on FEI's operational resources. Due to the demands which will already be placed on FEI's operations personnel during peak winter conditions in the affected region, including managing short term mitigation measures in multiple communities and managing other emergency situations which can arise during extreme weather events, FEI's existing internal resources may not be capable of managing the logistical challenges associated with supplying a significant capacity shortfall using CNG trucking. FEI would likely be required to rely heavily on contractors or on temporary personnel to manage the additional workload, which introduces additional risk of human error.

CNG/LNG Requirements Cannot be Precisely Forecast

It is not possible to precisely estimate the amount of CNG which will be required in a given winter. FEI can provide only a best approximation based on hydraulic modeling, but there is a possibility that actual requirements may exceed FEI's estimate. If this is the case, FEI may not have the resources in place to manage the actual shortfall, resulting in customer outages.

Costs Associated with Implementing CNG/LNG Introduce Unnecessary Costs to the OCU Project

As CNG/LNG trucking is not a viable long-term solution, and does not provide any lasting capacity benefit to FEI's system, FEI determined that deferral of the Project and implementation of CNG/LNG would inevitably result in higher overall costs to the customer. The costs associated with CNG/LNG trucking would include both an upfront cost to install necessary infrastructure, complete the necessary site upgrades, and purchase/rent required equipment, as well as operational and contractor costs which would escalate each year with increasing demand. These expenditures would not decrease the total cost of the required pipeline, and as such FEI would not consider them a prudent investment since they could be avoided by the timely construction of the OCU Project (which would be necessary in any event). Installation of this necessary pipeline infrastructure will allow FEI to reliably supply its customers without the undue costs and risks associated with using CNG/LNG trucking as a stopgap measure. This differs from the other proposed short-term mitigation measures because other measures do provide a lasting capacity benefit to the system, and therefore represent an appropriate investment.

11.2 Please provide an estimate of the number of CNG truckloads per hour and per day that would be required to meet peak demand in winter 2023/24 and 2024/25.

Response:

As explained in detail below, FEI would have to be prepared to deploy up to 16 truckloads of CNG per day in the winter of 2023/2024, and approximately 36 truckloads per day in the winter of 2024/2025. However, all estimates of CNG requirements are a best approximation only. It is difficult to accurately model the capacity benefits of CNG injection and the numbers provided below cannot be precise; FEI can provide only its best estimation of the likely future requirements. As noted in the response to BCUC IR1 11.1, FEI does not consider CNG and/or LNG supplementation to be a practical or appropriate means of addressing or deferring the OCU Project, instead considering CNG and/or LNG supplementation valuable and useful emergency response tools.

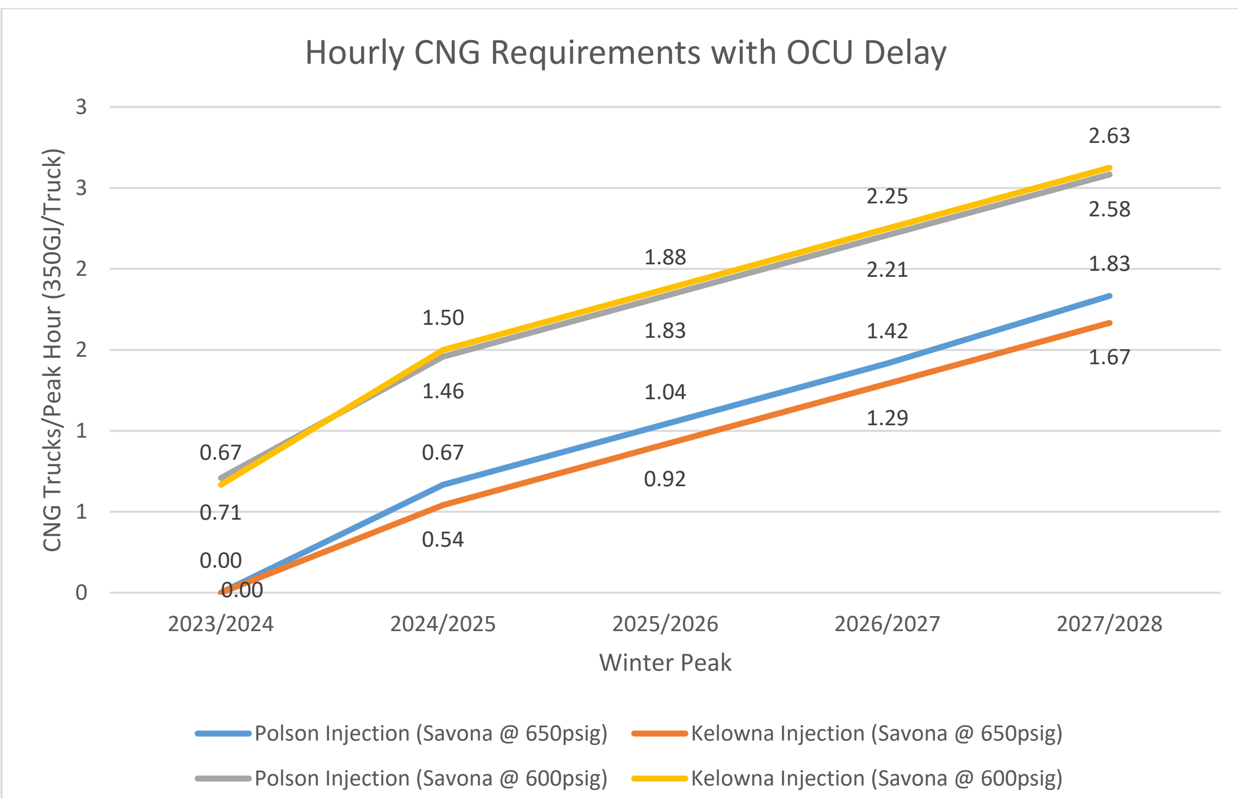
As discussed in Section 4.2.1 of the Updated Application, FEI has negotiated an understanding with Enbridge to attempt to maintain a higher minimum pressure of 650 psig at Savona, where gas enters FEI's system. However, FEI cannot depend on this pressure in its forecasting as Enbridge does not have a firm contractual obligation to supply this increased pressure and historically observed pressures at Savona have dropped as low as 600 psig during periods of peak demand.

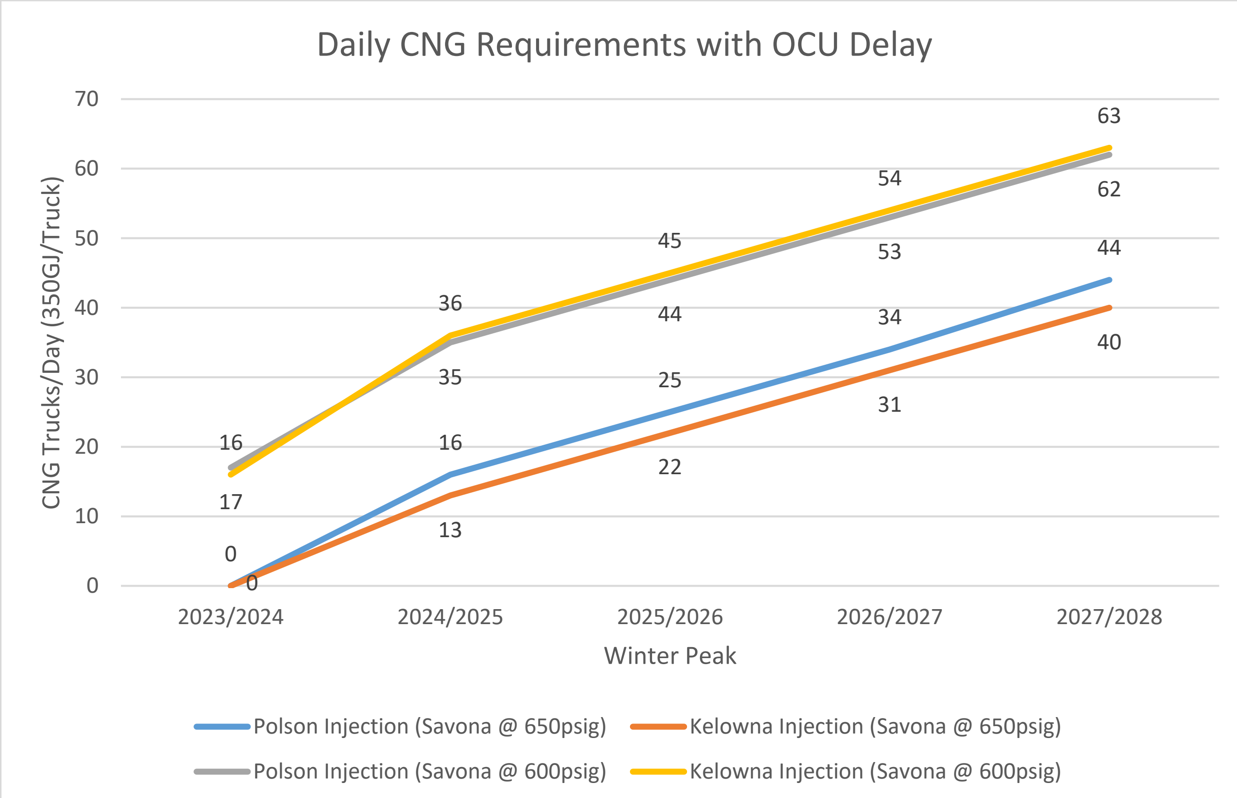
The graphs below show the required hourly and daily CNG truckloads at peak demand, with Savona at both 600 psig and at 650 psig. With Savona supplying gas to the ITS at 650 psig, and all other mitigation measures in place, FEI estimates that demand could be just met in the winter of 2023/2024 without CNG. By the winter of 2024/2025, even with Savona delivering gas at 650 psig, 13 to 16 truckloads of CNG per peak day (i.e., just under a truckload per peak hour) would be required to maintain system capacity at a minimum acceptable level. Note that this is a best-case scenario, as FEI cannot rely on a pressure of 650 psig at Savona.

With Savona supplying gas to the ITS at 600 psig, a significant amount of CNG would be required during peak conditions in the winter of 2023/2024. This requirement would escalate rapidly over subsequent years as demand increases. In 2023/2024, FEI projects that 16 to 17 truckloads of CNG per day would be required, depending on whether injection is at Kelowna #1 Gate Station or at Polson Gate Station. This correlates to just below 1 truckload per peak hour. By the winter of 2024/2025, 35 to 36 truckloads of CNG would be required every peak day, corresponding to approximately 1.5 full truckloads per peak hour. Based on the forecasts above, FEI's experience with CNG supplementation described in BCUC IR1 11.4.1 could be similar in scope (20 to 24 truckloads of CNG per day compared to 16 to 36 truckloads per day) to what would be required in the winter of 2023/2024.

In reality, FEI is likely to experience a situation between these two extremes; pressures at Savona are likely to fall between 600 to 650psig, meaning that the requirement for CNG during a peak weather event would fall between zero and 16 truckloads per day in the winter of 2023/2024. However, to maintain reliable service to its customers, FEI must plan for the worst-case feasible scenario, which is a pressure of 600 psig at Savona coinciding with a peak cold weather event. Therefore, should the OCU Project be delayed, FEI must be prepared to deploy 16 truckloads of CNG per day in the winter of 2023/2024, and 36 truckloads per day in the winter of 2024/2025. As discussed in the response to BCUC IR1 11.1, FEI's operational resources would be challenged to coordinate a response of this level during peak winter conditions when they would already be called upon to implement other mitigation measures such as operating manual station bypasses. As such, this solution is not reliable or practical, and becomes rapidly less feasible as demand continues to increase over time.

The graphs below show the rapidly escalating requirement for CNG, should the installation of the OCU Project be delayed. These numbers represent FEI's best approximation of the projected supplementation.





11.3 Please discuss whether temporarily introducing CNG and/or LNG as a short term measure from 2022/23 could enhance the viability of any of the Project alternatives not selected by FEI, as outlined in section 4 of the Updated Application.

Response:

Temporary introduction of CNG and/or LNG from 2022/23 would not enhance the viability of the other Project alternatives.

As discussed in responses to BCUC IR1 11.1 and 11.2, CNG/LNG injection is not a practical long-term solution to address the increasing shortfall in the winters of 2023/2024 and beyond, and becomes logistically infeasible in the years following. The timelines for proposed Alternatives 4 and 5 fall outside of this timeline.

As discussed in Section 4.6.2.2 of the Updated Application, Alternatives 1 and 2 have a high degree of risk associated with their schedules. Considering the additional risks and challenges laid out in response to BCUC IR1 11.1, temporary use of CNG and/or LNG would not mitigate the risk sufficiently to make either the preferred alternative.

11.4 Please describe in detail the reliability concerns associated with using a) CNG supplementation and b) LNG supplementation to meet demand on a peak day event.

Response:

a) Transportation via pipeline is more reliable than transportation via truck. Pipelines typically have a very high availability and disruptions to pipeline supply are infrequent. A new pipeline such as the proposed OLI PEN 406 extension will be unlikely to experience service disruptions. Truck transportation is far more likely to be disrupted by events such as inclement weather (which FEI would expect to be a significant factor should CNG be used to supplement supply during peak winter conditions), traffic accidents, mechanical breakdowns, road closures, heavy traffic, or dispatching issues. Traffic accidents and road closures are frequent in the British Columbia Interior during winter conditions due to heavy snowfall and ice causing dangerous driving conditions and poor visibility. The consequence of delays to CNG trucks would be an inability to maintain system capacity, and a loss of supply to customers during the coldest days of the year when demand is at its highest and reliable gas service is most critical.

b) Concerns related to reliability of trucking are applicable to LNG as much as they are to CNG. In this case, fewer trucks would be required due to the higher energy density of LNG when compared to CNG. However, trucks would be required to travel much further (from FEI's Tilbury LNG Facility in Delta, BC) and would be required to travel through the Coquihalla Highway passes. Trucking does continue through this region in the winter, but delays and road closures are frequent during the winter. According to the MOTI, the Coquihalla Highway has closed entirely due to avalanche risk nearly once per year since its construction. Vehicle incidents such as collisions and accidents due to weather conditions cause highway closures even more frequently. As these closures typically occur during the coldest days of the year, when LNG supplementation would be required, there is a high probability that a road closure or accident would prevent LNG trucks from reliably reaching the injection point in Kelowna or Vernon. The resulting capacity shortfall could lead to a loss of supply to customers during the coldest days of the year when demand is at its highest and reliable gas service is most critical.

11.4.1 Please discuss FEI's experience with using CNG and LNG supplementation to meet peak demand elsewhere on its system.

Response:

CNG Supplementation:

FEI used CNG supplementation during the supply disruption resulting from the Enbridge pipeline failure in October 2018. FEI engaged a contractor who supplies and operates CNG equipment to assist maintaining gas supply while Enbridge repaired its pipeline. This was undertaken as an emergency response activity to events outside FEI's control (the Enbridge pipeline incident), and as a proof-of-concept for CNG backup during similar situations. It was materially different from delaying a required major capacity upgrade.

In this instance, a compression site was set up near Princeton. A temporary workspace was acquired to accommodate space requirements as the existing right-of-way space was insufficient. An electrical upgrade to the site was required to run the required two compressor units. These units were supplied by the CNG provider and tied into FEI's system at the Princeton location. Filling each truck at this site took approximately 1.5 to 2 hours.

A decompression site was set up at FEI's Bradshaw Station in Abbotsford and tied in to FEI's system. This site was selected due to a requirement for a significant amount of space for decompression equipment and trucks to allow up to three trucks to unload concurrently with staging room for a fourth. Site prep was required to accommodate the trucks and equipment trailers and, similar to the compression site, some electrical modifications were required.

CNG trucks filled at the Princeton compression site, then travelled to Abbotsford where trucks could hook up to the decompression units for unloading. Typically, emptying each truck took up to two hours. Approximately 20 to 24 trucks per day were moved over approximately 60 days when the CNG supplementation operation was undertaken. Note that in this case, lower reliability was acceptable as CNG trucking was not being used to support system pressures. This proof of concept was primarily a gas supply exercise due to reduced throughput of the Enbridge pipeline, and hence delays to trucks due to road conditions, logistical difficulties, or any other reason would not have resulted in degradation of pressures and a corresponding loss of supply to customers.

Therefore, there was less concern regarding the inherent reliability challenges associated with maintaining a steady supply via trucks during the winter. In this situation, CNG supplementation was a valuable tool to supplement gas supply, and a valuable proof-of-concept. However, as discussed in the response to BCUC IR1 11.1, the reduced reliability associated with trucking when compared to pipeline transport is not acceptable to FEI when a delay to the truck supply will cause uncontrolled pressure drops in the system and a resulting loss of supply to customers, as in the case of the OCU Project.

LNG Supplementation:

FEI used temporary LNG supplementation on the distribution system in Whistler, BC to mitigate a capacity shortfall while the permanent pipeline solution was implemented. The volume of gas supplied via LNG was significantly less than what was transported via CNG truck during the Enbridge incident.

In this case, a temporary regasification and injection facility was set up in Whistler, consisting of a rented mobile regasification trailer, a rented ambient air mobile vaporization trailer, a pressure regulating station, and secondary containment for the LNG trailers. Trailers were filled at FEI's Tilbury LNG facility in Delta, B.C., and trucked to the regasification facility in Whistler where the trailers were parked next to the regasification trailer. The trailers were left attached to the regasification facility, and the LNG was vaporized as needed and injected into the system.

C. DESCRIPTION AND EVALUATION OF ALTERNATIVES

12.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 3.1, p. 11
ITS gas supply strategy

On page 11 of the Updated Application, FEI states:

> FEI's ITS interconnects the gas supply from the Enbridge owned Westcoast Energy System in the west (Westcoast system) and the TC Energy-owned Foothills Pipeline in the east (TC Energy pipeline). Under typical conditions, gas is taken from the Westcoast system at the Savona Compressor Station to supply FEI's customers in the Thompson and north Okanagan Regions, while FEI's customers in the south and central Okanagan Regions are supplied primarily by the Southern Crossing Pipeline (SCP) supplying Oliver, which, in turn, supplies pipelines delivering gas through the Penticton area.

12.1 Please describe FEI's current natural gas supply strategy for the ITS and how this strategy is expected to evolve over the medium and long term.

Response:

FEI's natural gas strategy for the ITS is to develop a plan to ensure there are enough physical gas supply resources in the portfolio to meet the forecast load requirements for the customers served by ITS. This is achieved by not only evaluating the resources available to the Interior customers, but also to other service regions as well, specifically the Lower Mainland. This helps FEI design a robust gas supply portfolio that matches the load requirements of its customers in all service regions with secure and cost effective supply. The fundamental principles of constructing such a portfolio include:

- Meeting peaking and/or shorter duration load requirements with cost-effective on-system LNG storage resources or commercial peaking supply arrangements;
- Meeting short to medium duration seasonal load requirements (5-30 days) with off-system underground storage, depending on its location and characteristics; and
- Contracting pipeline capacity to meet long duration load requirements as pipeline capacity is the most cost-effective method to supply gas over long periods (151 to 365 days).

As FEI obtains most of its natural gas from Station 2 in northeast BC via the Enbridge-owned Westcoast T-South system, its current gas supply strategy is to place more emphasis on diversifying its supply since the October 9, 2018 pipeline rupture and the capacity restrictions imposed thereafter on the Westcoast system.

FEI's current and medium-term strategy for Interior customers will be to continue to source incremental supply when required at the AECO/NIT and/or East Kootenay marketplace instead of sourcing more Station 2 supply. This is also a major reason why the OCU Project aligns with FEI's broader gas supply strategy. Purchasing incremental supply at the AECO/NIT marketplace requires FEI to hold additional pipeline capacity on TC Energy's NOVA Gas Transmission and Foothills pipeline systems for which FEI would pay fixed demand charges for 365 days each year. Given the seasonality and peaking demand of the Interior customers, FEI determined that the utilization of the incremental TC Energy pipeline would be low and not a cost-effective gas supply strategy. Instead, FEI's gas supply strategy has been to contract peaking supply arrangements with counterparties to deliver AECO/NIT gas at the East Kootenay interconnect. This option requires FEI to pay a call option premium to have the right to receive gas at East Kootenay when it is required. The option is more cost effective than AECO/NIT supply and also provides operational flexibility to optimize the supply on a daily basis. Further, FEI would only secure these types of commercial arrangements at East Kootenay because they would be more costly at Savona and at Huntingdon. For example, there is approximately 2.8 Bcf/day of gas flowing past East Kootenay on a daily basis (approximately 1 Bcf/day more than at Huntingdon). Therefore, commercial arrangements are more readily available at East Kootenay compared to its counterpart at Huntingdon. FEI will continue to monitor the changes in the Interior demand and market conditions so that the strategy can be adjusted in a timely manner to support gas supply objectives of shaping supply to match demand with resources available in the marketplace.

FEI's long term gas supply strategy will continue to focus on improving diversity of supply, as well as gas supply resiliency, while providing secure and cost-effective supply to FEI's customers. In order to achieve the objectives, FEI optimizes the gas supply portfolio on an annual basis taking into consideration the changes in demand, supply, and resources available in the region. The OCU Project also aligns with FEI's long term gas supply strategy discussed in the proposed Tilbury LNG Storage Expansion Project CPCN Application[5]. For example, Figure 3-8 of the Updated Application shows that, with the OCU Project, there will be sufficient capacity to support peak demand until 2029/2030. After that period, compressor station upgrades to the SCP would be required based off the current forecast and if the Tilbury LNG Storage Expansion is not approved. However, if the Tilbury LNG Storage Expansion is approved, FEI could delay these compressor station upgrades for capacity related reasons from 2030 to beyond 2040, thereby potentially deferring approximately $20 to $30 million of capital costs.[6] This could be achieved because the additional LNG storage and gasification capabilities at Tilbury would enable FEI to backfill supply into the Lower Mainland on extremely cold winter days, while diverting AECO/NIT and East Kootenay supply to the BC Interior. This may also involve reducing flows into Westcoast at Kingsvale to provide supply into the OCU Project capacity at Oliver.

---

5 https://www.bcuc.com/Documents/Proceedings/2021/DOC_60434_B-1-FEI-Tilbury-LNG-CPCN-Application-REDACTED.pdf.

6 FEI notes that there could be other compression upgrades required in a 20 year horizon as a result of pipeline integrity, compressor unit reliability and/or emission reduction efforts, which could impact the timing and the approximate deferred capital costs discussed in this IR response.

12.1.1 Please explain how each alternative for the OCU Project aligns with this gas supply strategy.

Response:

The three alternatives that were deemed feasible for the OCU Project align with the gas supply strategy discussed in the response to BCUC IR1 12.1. Each of the three alternatives assists FEI in developing an efficient gas supply portfolio by enhancing its supply diversity given that they all require supply from AECO/NIT, instead of from Station 2. Further, the OCU Project also aligns with other FEI gas supply projects, specifically the Tilbury LNG Storage Expansion, also discussed in the response to BCUC IR1 12.1.

12.1.2 Please discuss whether FEI's broader gas supply strategy for its entire system is a consideration when planning capacity upgrades on the ITS.

Response:

Please refer to the response to BCUC IR1 12.1.

13.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 3.3, pp. 19-20

Capacity with the OCU Project

On page 20 of the Updated Application, FEI provides the Figure 3-8 illustrating both the current capacity and the capacity of the ITS following completion of the OCU Project.

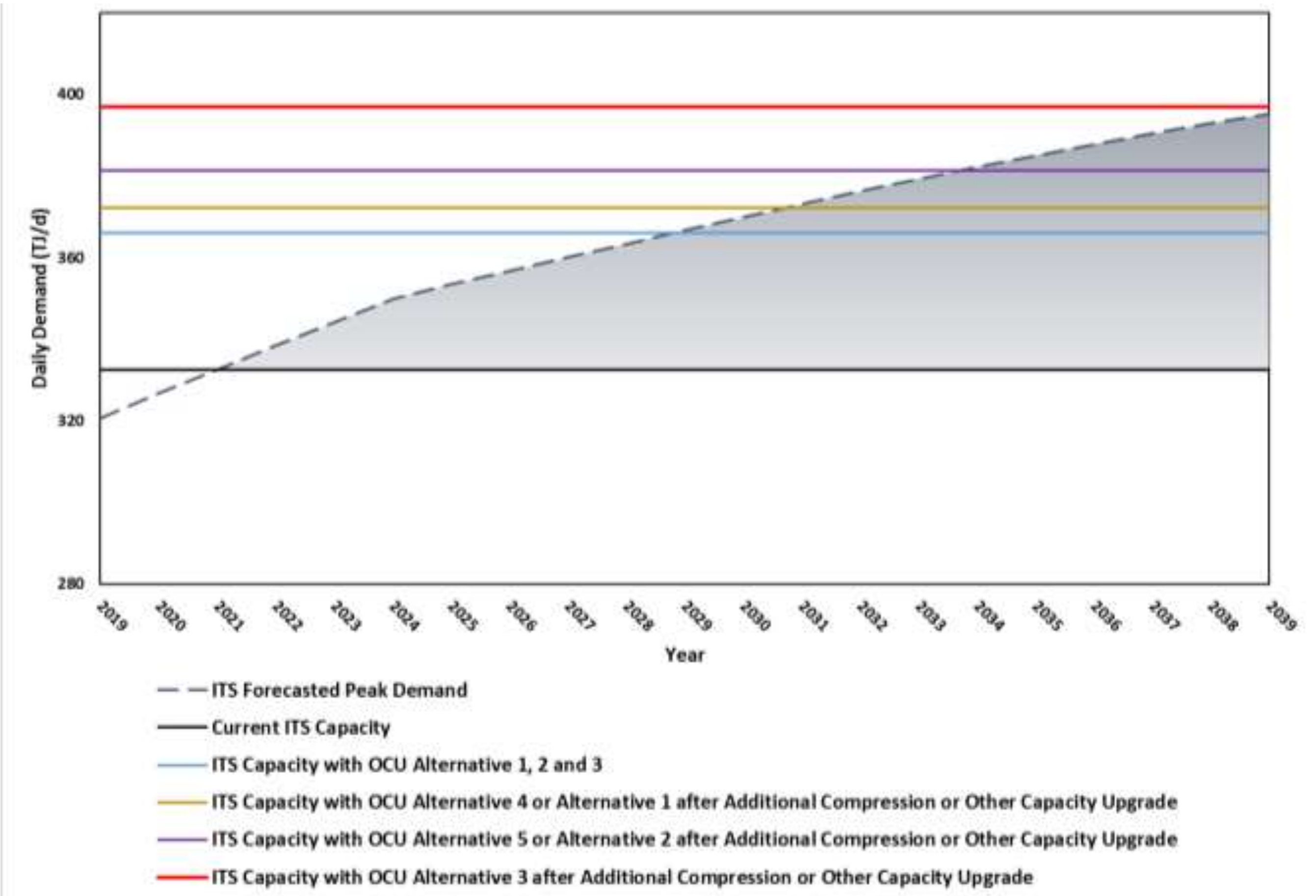
13.1 Please provide a graph similar to Figure 3-8 illustrating the capacity of the ITS with each Alternative.

Response:

The following graph shows Figure 3-8 with an additional line added to show the capacity of the ITS after installation of each alternative. There is effectively no capacity difference between Alternatives 1, 2, or 3 prior to a future capacity upgrade (such as a compressor upgrade at Kitchener), so their capacity is shown as a single line indicating the point at which a compression upgrade, or other capacity solution, as described in the response to BCUC IR1 14.3 will be required in 2029. The ITS capacities of each of Alternatives 1, 2, and 3 combined with a future compressor station upgrade at Kitchener (but with no other upgrades) are also shown in the graph.

The capacity of Alternative 4 with lateral upgrades in 2028, and Alternative 1 with the Kitchener Compressor upgrade overlay each other on the graph and have sufficient capacity to 2031; each would then require additional upgrades to meet the forecast. Alternative 5 and Alternative 2 with the Kitchener Compressor upgrade overlay each other on the graph; each would provide sufficient capacity until 2034 and would then require additional upgrades. Alternative 3 with a future Kitchener Compressor upgrade has capacity to meet the forecast demand beyond 2039. This difference in the longer term ability to meet forecast demand illustrates the benefit of the preferred Alternative 3 reinforcement in the south over the other alternatives.

ITS Capacities for each OCU Project Alternative



13.2 Please describe the methodology and assumptions that FEI uses to calculate the ITS capacity with each Alternative.

Response:

FEI uses the same methodology and assumptions for assessing the capacity of each alternative. Depending on the nature of the upgrade alternative, the constraints determining capacity limits may differ. FEI first builds a hydraulic model of the ITS with the alternative represented. Starting with the assumptions presented in Section 3.3.2 of the Updated Application (i.e., that the available supply pressure into the system is set, and that the MOP pressure restrictions are respected), FEI creates a number of models that include the forecast peak day loads and that represent each year in the forecast. For additional clarity, the models consider the following:

- The forecast peak day loads are added to the model at each delivery point (gate station) where gas enters the downstream intermediate and distribution pressure systems;

- The load is distributed among the delivery points to represent the demand of both current customers and the forecast new customers in each year; and
- The model is repeatedly loaded with the forecast demand for each successive year until a system constraint is observed.

These system constraints manifest themselves either as:

- An unacceptably low pressure condition that occurs either at a downstream regulating station or compressor station inlet; or
- A lack of adequate compressor power at a compression station.

FEI considers the load on the system in the year the constraint is observed as the capacity limit of the system. This capacity limit is represented on the peak demand forecast plots as a horizontal line intersecting the demand forecast in the year the constraint is observed to occur. Although this is a simple and convenient way of representing system capacity, this method does not fully convey the complexity of the various interactions within the hydraulic model that determine the limiting constraint.

For the ITS, without upgrades, the capacity limit is reached (even with short-term mitigation measures in place) after the winter of 2022-2023.

Alternatives 1, 2, and 3 reinforce the system between Penticton and Kelowna, by eliminating a bottleneck and allowing demand growth to be supported by gas delivered from Yahk on the SCP to Oliver Y Control Station (Oliver) and then north into the Okanagan. The next constraint on the system then appears in 2029. This constraint is insufficient inlet pressure at Oliver. The constraint occurs because, by that time, the Kitchener Compressor, which moves gas westward through the SCP, would no longer have sufficient power to deliver gas to Oliver with adequate pressure to feed to pipelines that leave that facility (the Kingsvale Oliver pipeline, and the South Okanagan Natural Gas pipeline that feeds the Alternative 1, 2, or 3 pipelines). Once this constraint is removed (by adding additional compression), these OCU Project alternatives would have additional capacity to meet the forecast load, as described in the response to BCUC IR1 13.1.

For Alternatives 4 and 5, the constraint that limits capacity will not initially be the Kitchener Compressor power as those alternatives do not increase the flow (and power) requirements through that facility to the same extent as Alternatives 1, 2, or 3. For Alternative 4, the constraint occurs in 2031 and is because of low pressure upstream of the Kelowna #1 Gate Station. At that time, an extension of the pipeline loop (or some other comparable upgrade) would be required. For Alternative 5, the constraint would appear in 2034 and also because of low pressure upstream of the Kelowna #1 Gate Station. In order to address the low pressure, additional send-out on a peak day above the 51.44 MMscfd identified in the Updated Application would be required. An expansion at the LNG site could accommodate the additional demand; alternatively, to avoid expansion at the LNG site, FEI could consider other approaches such as pipeline looping to support the available LNG send-out capacity.

FEI states on page 19 of the Updated Application that the Figure 3-8 shows that, with the OCU Project, there will be enough capacity to support peak demand until the winter of 2029/2030. FEI explains in Section 3.3.2.4 the compression upgrades that would be undertaken at that time to further support peak demand to the end of the 20 year forecast period without extending the OCU Project pipeline.

13.3 Please describe any assessments to determine the feasibility of upgrading the compression capability to support peak demand to the end of the 20 year forecast period, including engineering and cost studies and provide the results of these assessments.

Response:

FEI initially considered including a compression upgrade at the existing Kitchener B compressor station within the scope of the OCU Project. This upgrade was based on the minimum requirements to meet the forecast 20-year capacity needs based on current operations, as envisioned when development of the Project started. The response to BCUC IR1 14.3 explains the rationale for removing this item from the final scope of work for the OCU Project, and the unknowns associated with future compression requirements. Based on this rationale and other learnings since, FEI no longer considers the assessments done to date to be valid or representative of FEI's future requirements.

14.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 3.3.2.4, p. 26

Future Compressor Upgrades

On page 26 of the Updated Application, FEI states:

> Based on the current forecast, by the summer of 2029 FEI will need to upgrade the compression capability on the SCP to improve capacity into the Central and North Okanagan. FEI is currently considering several possible options to increase compression capability on the SCP to meet a variety of possible future needs. As the compression requirement to address future capacity needs in the Okanagan is several years beyond the immediate need for the OCU Project, and the optimal location and extent of required additional compression cannot yet be determined, FEI did not include a compressor upgrade in the OCU Project. Compressor requirements to satisfy the longer term capacity needs would be included, as needed, as part of any expansion project contemplated on the SCP.

14.1 Please explain when FEI expects to be able to provide additional information about any future project(s) to increase compression capability on the SCP, including project overview, timing, or anticipated cost.

<u>Response:</u>

FEI is not able to provide the requested information at this time because future SCP compression requirements could change as resource developments in the region unfold over time. Further, as explained in the response to BCUC IR1 12.1, the recently filed Tilbury LNG Storage Expansion Project CPCN Application, if approved, could also impact the solution and timing of the potential compression upgrade.

FEI will monitor and assess future upgrades and/or extensions to SCP as part of its long-term infrastructure planning and related developments in the region.

14.2 Please discuss whether any FEI options to increase the compression capability on the SCP would require new transmission pipelines or recertification of any existing transmission pipelines to a higher pressure.

14.2.1 If so, please provide details of any new pipelines required and any existing pipelines requiring recertification.

<u>Response:</u>

Options that improve compression capability could significantly increase the capacity of the SCP to flow gas from Yahk to Oliver without recertifying the pipelines to higher pressures or requiring new pipelines in that corridor. The OCU Project Alternatives 1, 2 or 3 are examples that would move more gas north from Oliver though the SCP with enhanced compression. To move the gas westward beyond Oliver, FEI would encounter capacity constraints; therefore, new pipelines would be considered as part of any expansion project contemplated on the SCP.

14.3 Please explain why compression upgrades on the SCP are planned to address future capacity needs in the Okanagan (beyond 2029) and not the immediate need identified for the OCU Project.

Response:

The need for the OCU Project cannot be deferred by advancing the future compression additions alone; the proposed pipeline is a necessary first step. The planned compression upgrade, in isolation, cannot address the forecast capacity shortfall as the VER PEN 323 pipeline, operating at its current MOP, acts as a bottleneck in the system between Penticton and Kelowna. Increasing compression upstream of the VER PEN 323 pipeline, to provide the capability to improve the upstream system pressures and move more gas into the pipeline toward the Okanagan, does little to alleviate the capacity shortfall. This is because the pressure reduction that must be applied at the Ellis Creek Control Station and the high pressure loss in the length of the existing VER PEN 323 pipeline between Penticton (Ellis Creek) and Kelowna would not allow any improvement in flow and pressure to be delivered as far as Kelowna in the existing system. In effect, this downstream portion of the system would operate in the same way as it currently does with the same constraint. Until FEI addresses the ability to move more gas from Penticton to the north at a lower rate of pressure drop per kilometre, the system cannot take advantage of improved compression at Kitchener – or anywhere else upstream of the proposed OLI PEN 406 Extension.

If the Updated Application is not approved, and as a result the OCU Project is not in service by the winter of 2023/2024 as planned, the result would be insufficient system capacity to serve customers in the region. Further, without the OCU Project, the future compressor upgrade would not be required, as installing compression alone would not improve the low pressure at stations serving FEI's customers in the north and central Okanagan.

FEI has chosen to not include the future compression requirements in the scope of the OCU Project, as FEI will be better able to ensure that the compressor upgrade that ultimately proceeds is appropriate for the needs of the ITS at that time. If this upgrade were included in the scope of the OCU Project, FEI could be left with compression assets that integrate poorly or do not support future needs effectively. In this case, a second upgrade project would likely be required, potentially moving compressor units to a new location more appropriate for the evolving system needs. Also, as discussed in the response to BCUC IR1 12.1, if the Tilbury LNG Storage Expansion Project is approved, FEI could delay these compressor station upgrades for capacity related reasons. As a result, FEI does not yet have all the information necessary to optimize the sizing and location of the needed compressor upgrade. Since the compressor upgrade is not required immediately, and cannot be used to defer the pipeline upgrade if installed at this time, FEI determined that the most cost-effective solution for the OCU Project is to plan future compression upgrades on the SCP to address capacity needs on the ITS as they develop.

14.4 If the Updated Application were not approved as applied for, what would the implications be, if any, on the need or timing of future compressor upgrades on the SCP? Please discuss.

Response:

Please refer to the response to BCUC IR1 14.3. Advancing the timeline for the compression upgrade cannot defer the need for the OCU Project pipeline upgrade, and deferring the pipeline upgrade will not delay the requirement for a compression upgrade.

14.5 Please discuss how the future expansion of compression capability on the SCP and FEI's overall vision for expanding system capacity in the Okanagan factored in FEI's decision-making when determining which alternative should be proposed for the OCU Project.

Response:

Alternatives 1, 2, and 3 all enable FEI to maximize the use of the existing SCP pipeline system capacity and align with FEI's overall gas supply strategy. The need for compression will be addressed at a later point in the forecast period to ensure that the project is designed and scheduled appropriately to meet FEI's evolving customer demand needs. Please also refer to the response to BCUC IR1 12.1.

15.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.1.2, p. 32

Compression Option

On page 32 of the Updated Application, FEI states:

> In order to meet the Project's objectives, FEI identified and investigated five alternatives, including four pipeline installation options and an LNG (Liquefied Natural Gas) storage/peak shaving option.

15.1 Please discuss whether FEI considered adding compression to the ITS in the Okanagan area as a possible alternative to meet the OCU Project's objectives.

15.1.1 If yes, please describe any assessments to determine the feasibility of installing compression on the existing ITS, including engineering and cost studies and provide the results of these assessments.

15.1.2 If yes, please explain why FEI did not identify a compression option as a Project alternative.

Response:

No, FEI did not consider adding additional compressor facilities within the Savona to Penticton corridor as an alternative to meet the OCU Project objectives. Due to the high variability in system load over the peak day period on the system and due to the system being broken into several different segments with different MOP constraints, FEI determined a compressor alternative to be operationally infeasible.

The system configuration and load profile would not allow a compressor to operate continuously for any period of time, resulting in frequent starts and stops of the compressor. A critical period for compressor operations is start up and shut down. There is a high possibility on any startup sequence that it will initially be unsuccessful which delays the ability of the compressor to address system peak requirements reliably. The resulting intermittent operation would not be feasible for managing peak day system loads and line pack.

Additionally the compressors do not provide operational benefits outside of peak days in winter. For example, compressors do not add line pack to the system as the OCU Project pipeline will. Increasing the available line pack provides a significant benefit for FEI Gas Control in managing gas supply in daily operation of the system throughout the year. A compression alternative similarly would not provide line pack in summer to support operations and maintenance work on the system that the other alternatives considered can provide. Compressors suitable for operation under peak demand would not be in operation when system demand is low and when such operations work is performed.

Finally, a compressor alternative would be difficult to expand to address future load growth beyond the forecast period. The operating pressure reduction within the greater Kelowna area to 4,654 kPa (675 psig)[7] would become the next bottleneck to capacity on the ITS to serve the Okanagan region that a compression alternative could not address. Extending the pipeline looping would be required to address this, and building on the proposed Alternative 3 loop provides a means that could address peak demand growth beyond the current forecast.

For these reasons, FEI did not include additional compression facilities within the Thompson and Okanagan regions for consideration as an alternative to address the current capacity constraint.

7 See line 3 in Table 3-1 of the Updated Application.

16.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.2.1, p. 34

Savona Compressor Station

On page 34 of the Updated Application, FEI states:

> FEI has established a working agreement with Enbridge to maintain a minimum delivery pressure into Savona of 4480 kPag (650 psig) on peak days. This is 345 kPag (50 psig) higher than FEI's normal expected minimum delivery pressure at Savona. This will improve pressure into the north and central Okanagan and is required in the winter of 2021-22 and 2022-23 in advance of the completion of the OCU Project, but is not sufficient on its own to mitigate forecast peak demand in those winters.

16.1 Please provide the historical minimum delivery pressure into Savona on peak days for the past five years.

Response:

The following table shows the lowest hourly delivery pressure from the Enbridge-owned Westcoast system at Savona for the coldest day in each of the last five years. In December 2016, Enbridge was conducting mid-winter in-line inspection on its system resulting in the pressure dropping below 600 psig on the coldest day of December 16, 2016. The table also shows the next coldest day for 2016 when pressures remained above 600 psig.

Minimum Delivery Pressure into Savona Tap on Coldest Days 2016-2020

Year	Date	Kelowna Temp (ºC)	Kelowna DD	Lowest Savona Tap Pressure (psig) in the Morning Peak Hour
2016	2016-12-16	-17.5	35.5	556
	2016-12-14	-16.9	34.9	617
2017	2017-01-11	-17.8	35.8	615
2018	2018-02-21	-13.6	31.6	624
2019	2019-02-05	-15.8	33.8	694
2020	2020-01-14	-18.9	36.9	755

16.1.1 Please provide the current capacity of Savona Compressor Station. Please provide any assumptions made in determining current capacity, including the inlet pressure to the compressor station.

Response:

The FEI Savona Compressor Station is located approximately 3.7 km east of the Savona tap off the Enbridge system. The station is equipped with two identical Solar Turbines Saturn 20 gas turbine compressors. After allowing for piping and thermal losses, and mechanical efficiency, the actual available horsepower from each unit is 1,550 HP. Therefore, the total power output of the Savona Compressor station is 3,100 HP. The highest discharge pressure is 960 psig. The expected minimum delivery pressure of 600 psig into the Savona tap off the Enbridge system is assumed. However, due to the 3.7 km distance between the Savona tap and the compressor station, the pressure at the suction side of the compressors would be lower than 600 psig. At the forecast peak demand in 2039-2040 with Alternative 3, the suction pressure of the station with the Savona tap pressure at 600 psig is about 563 psig. When operating at the full 3,100 HP, the compressors would discharge at 892 psig.

17.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.3.2, pp. 39-40

Alternative 2 – Modified ITS Upgrades to VER PEN 323

On pages 39 and 40 of the Updated Application, FEI provides the following description of Alternative 2:

> This alternative proposes the installation of a 6 km 406 mm pipeline extension of OLI PEN 406 (SONG pipeline built in 1994) around the City of Penticton. The 6 km long extension proposed under this alternative eliminates the requirement to replace and/or retest multiple segments from the southern end of Alternative 1….
>
> This alternative would require a new regulating station with a 406 mm receiving barrel to be built at the northern end of the extension where the new 406 mm pipeline would tie-in to the existing VER PEN 323, as the two pipelines do not operate at the same MOP. All upgrades that are part of Alternative 1 which are located north of the tie-in would still be required under Alternative 2; this equates to replacement of 3.9 km of existing VER PEN 323 with new higher strength 323 mm pipeline followed by hydrotesting of the VER PEN 323 located north of the tie-in location to the proposed end point of upgrades so that the pipeline can be recertified to operate at a MOP of 6,619 kPa.

Further on page 40, FEI states that Alternative 2 would need to be completed in its entirety prior to the winter of 2023/2024 to avoid a capacity shortfall.

17.1 Please explain how FEI determined that Alternative 2 would need to be completed in its entirety prior to the winter of 2023/2024 to avoid a capacity shortfall.

<u>Response:</u>

To make this determination, FEI created a model of the ITS with the 6 km loop installed, but without the necessary upgrades to the VER PEN 323 pipeline. In this scenario, the pressure in the VER PEN 323 pipeline cannot be increased as rehydrotesting would not have been completed. The winter 2023/2024 demand forecast scenario was then run using this model. The results showed projected pressures at key points in the ITS (such as the inlets to the Kelowna #1 and Polson Gate Stations) dropped below FEI's acceptable thresholds. Therefore, in isolation, installation of the 6 km pipeline extension does not provide a sufficient pressure increase to the system to maintain capacity for the winter of 2023/2024.

It is not practical to increase pressure in the VER PEN 323 pipeline in stages; to avoid the unnecessary cost of installing additional pressure control facilities, rehydrotesting must be fully completed along the length of the pipeline from the 6 km extension tie-in point to the northern tie-in point before the operating pressure can be increased.

17.1.1 Please describe any assessments to determine the ITS capacity with only the 6 km 406 mm pipeline extension and the new regulating station completed prior to the winter of 2023/2024.

Response:

While it would be possible from a scheduling perspective to complete a 6 km pipeline extension and new regulating station prior to the winter of 2023/2024, this would not address the capacity need for the Project. FEI's system capacity models demonstrate that without increasing the pressure in the VER PEN 323 pipeline, which would require rehydrotesting to be complete, the capacity shortfall cannot be met in the winter of 2023/2024. Please also refer to the response to BCUC IR1 17.1.

17.2 Please discuss the feasibility of completing the 6 km 406 mm pipeline extension and the new regulating station prior to the winter of 2023/2024 and upgrading VER PEN 323 later.

Response:

Please refer to the responses to BCUC IR1 17.1 and IR 17.1.1, which explain why this scenario would not meet the required timelines for the necessary capacity increase.

Alternative 2 must be completed in its entirety prior to the winter of 2023/2024 in order to maintain adequate capacity on the ITS. Completion of the 6 km pipeline extension and the new regulating station would not be sufficient to address the capacity shortfall. FEI's timeline for rehydrotesting and rehabilitating the VER PEN 323 pipeline remains uncertain, which makes planning a staged approach challenging. The length of time required to complete hydrotesting and any associated repairs is not known, and this uncertainty adds a high level of risk to planning and executing a staged project. Even if FEI determines a method of supplying the system for the winter of 2023/2024, such as the use of CNG, there is no guarantee that the VER PEN 323 pipeline would be fit for service at a higher pressure by the next winter. This could leave FEI without any available mitigation measures, and customer demand which could not be met.

18.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.3.3, p. 41

Alternative 3 – OLI PEN 406 Extension

On page 41 of the Updated Application, FEI states Alternative 3 involves the addition of approximately 30 km of 406 mm pipeline running from OLI PEN 406 (SONG pipeline built in 1994) east of Ellis Creek near Penticton to Chute Lake northeast of Naramata.

18.1 Please explain how FEI determined the pipeline length for Alternative 3.

18.1.1 Please describe any assessments to determine the optimal pipeline length of the OLI PEN 406 Extension, including engineering and cost studies and provide the results of these assessments.

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

The objective of the proposed pipeline is to overcome the capacity restriction in the VER PEN 323 pipeline between Penticton and Kelowna by moving the pressure control station (currently at Ellis Creek in Penticton) supplying gas into the pipeline at 750 psig to a point far enough north to provide the required capacity. FEI determined a project scope for Alternative 3 that could meet or exceed the current 20-year forecast and which could be built on with complementary projects to meet demand growth beyond the forecast horizon. To provide sufficient capacity to exceed the 20-year forecast, the point for supplying gas into the VER PEN 323 pipeline at 750 psig needed to be 28 kilometres north of the current location. The length of the proposed pipeline cannot be shortened without advancing the time that a future capacity constraint would occur in the current 20-year forecast period. This is because a shorter pipeline would leave a longer length of the smaller existing VER PEN 323 pipeline carrying the peak gas demand, resulting in a higher pressure loss and advancing the time when the low pressure constraint appears. The critical factor for increasing the system capacity is the tie-in location of the new Chute Lake Station on the existing VER PEN 323, and not the length or diameter of the new pipeline being installed to the tie in point. In order to accommodate a variety of project needs the proposed pipeline has an alignment that extends more than 28 kilometres before it intersects with the VER PEN pipeline. The additional length does not impact the ability of the Project to meet the 20-year forecast.

FEI has identified a project similar to Alternative 3 in its long term plans for many years. The project was first mentioned in the Terasen Gas Inc. 2004 Resource Plan and was described as a 23 kilometre NPS 20 pipeline with a projected in-service date prior to winter 2010-2011. In the intervening years the project scope and timing evolved along with new peak demand forecasts. In the 2017 LTGRP, the project was described as a 28 kilometre NPS 20 pipeline with a required in-service date prior to the winter of 2022-2023. The additional 5-kilometre length provided the additional capacity to support the 20-year peak demand forecast available at that time.

As Alternative 3 for the OCU Project moved into a higher level of development, aspects of the project other than length were also assessed. The minimum length of the pipeline was fixed as described above, but the pipe diameter required could vary. The pipe needed to be large enough to deliver gas from the OLI PEN 406 while retaining sufficient pressure at the end point to deliver 750 psig gas into the VER PEN 323 pipeline, with additional pressure available to allow it to be extended in future if required. As mentioned, earlier forms of the project suggested an NPS 20 (508mm) pipeline. As the new pipeline would tie into the existing SONG pipeline, an NPS 16 (406mm) pipeline, FEI explored extending the smaller diameter NPS 16 pipe. The assessment determined that an NPS 16 extension to the SONG pipeline could provide sufficient capacity to meet the current project need and be capable of being extended further north if needed to meet future needs. The selection of the NPS 16 pipe provides benefits by reducing the Project cost and improving the efficiency of pipeline integrity activities. The pipeline will form a continuous run of NPS 16 pipeline between Oliver and the new Chute Lake Station that can be inspected in a single uninterrupted in-line inspection (ILI) run.

18.2 Please discuss whether there is an opportunity for FEI to extend the OLI PEN 406 beyond the OCU Project to further support peak demand on the ITS.

18.2.1 If yes, please explain whether this option is identified in the Updated Application.

18.2.1.1 If not, why not?

Response:

Please refer to the response to BCUC IR1 18.1.

18.3 Please discuss whether there is an opportunity for FEI to reduce OCU Project costs by reducing the length of OLI PEN 406 Extension, while still meeting the primary project objectives.

Response:

Please refer to the response to BCUC IR1 18.1.

18.4 Please discuss any potential OCU Project scheduling risks (permitting or construction) that factored in FEI's decision making when determining the pipeline length for Alternative 3.

Response:

As described in the response to BCUC IR1 18.1, the critical length for determining the pipe length was the location of the tie in point which, within reasonable margins, was not affected by the length of the new pipeline being installed. This allows the Project some margin to adjust the pipeline length to avoid alignments that may create scheduling risk.

19.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 3.3.2.1, p. 24, Section 4.3.4, p. 42

Alternative 4 – 508 mm Loop from Savona

On page 24 of the Updated Application, FEI states:

> FEI designs the ITS to deliver a minimum inlet pressure of 2415 kPag (350 psig) into the major gate stations serving downstream Intermediate Pressure (IP) systems on a peak day. This minimum pressure is the parameter that defines the ITS capacity limit. This minimum pressure is identified as the primary capacity constraint for this region in order to maintain a 350 kPag (50 psig) working pressure differential across Polson Gate Station and Kelowna #1 Gate Station that supply IP systems that operate at 2070 kPag (300 psig), supplying thousands of customers.

On page 42 of the Updated Application, FEI states, "The fourth alternative to address the capacity constraint involves the installation of a 508 mm loop starting at the Savona Compressor Station and running eastward for approximately 68.4 km before terminating east of Kamloops."

19.1 Please explain how FEI determined the 508 mm diameter and 68.4 km length for the pipeline starting at Savona Compressor Station proposed as Alternative 4.

<u>Response:</u>

The determination of project scope for Alternative 4 was consistent with the approach described for Alternative 3 in the response to BCUC IR1 18.1. FEI determined the length of the loop for Alternative 4 by moving the point on the existing SAV VER 323 pipeline where the new control station could deliver gas from the new pipeline loop into the existing pipeline to increase the pressure closer to the higher load centres in the Okanagan. The diameter of the new pipe was fixed at NPS 20 to match the existing pipe size between the Enbridge Compressor facilities and tap location at Savona and the suction of FEI's Savona Compressor Station (approximately 4 kilometres to the east). The length of NPS 20 looping identified met the 20-year requirements of previous peak demand forecasts. As explained in the response to BCUC IR1 13.1, this alternative would require additional enhancement by 2031 to meet updated peak demand forecasts.

19.1.1 Please provide the capacity of the pipeline solution proposed in Alternative 4, in both mmscfd and TJ/d units.

Response:

The capacity of Alternative 4 is approximately 372 TJ per day or 342 MMscfd, as illustrated in the figure in the response to BCUC IR1 13.1.

19.1.2 To the extent it is feasible, for each year in the forecast period (2021-2039), please provide the forecasted inlet pressures on a peak day at each major gate station within the ITS if the pipeline proposed in Alternative 4 were to be installed.

Response:

The table below shows the forecast inlet pressure for each major gate station within the ITS for the period 2021 to 2035, if the pipeline proposed in Alternative 4 were to be installed by 2023. As indicated in the response to BCUC IR1 19.1, Alternative 4 would need additional upgrades in 2031 in order continue to maintain the inlet pressures to these gate stations above the 350 psig minimum requirement.

Upstream Pressure at Major Okanagan IP Gate Stations

Year	Kamloops #1 psig	Polson psig	Kelowna #1 psig	Kelowna - Cary Rd psig
2021	640	297	316	377
2022	622	245	268	341
2023	746	445	430	486
2024	744	426	406	468
2025	743	414	391	458
2026	739	399	373	445
2027	734	383	354	431
2028	729	391	396	416
2029	724	380	373	400
2030	720	363	355	384
2031	715	*345*	*336*	367
2032	710	*327*	*317*	350
2033	705	*307*	*295*	*333*
2034	701	*287*	*274*	*315*
2035	697	265	251	296

20.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.4.2.1, p. 45

Alternative 4 Discussion and Analysis

On page 45 of the Updated Application, FEI states:

> Alternative 4 would meet one of the objectives for this project: to increase the capacity of ITS. However, the length and diameter of this pipeline would trigger an environmental assessment (EA). The anticipated timeline for completion of an EA is three years.

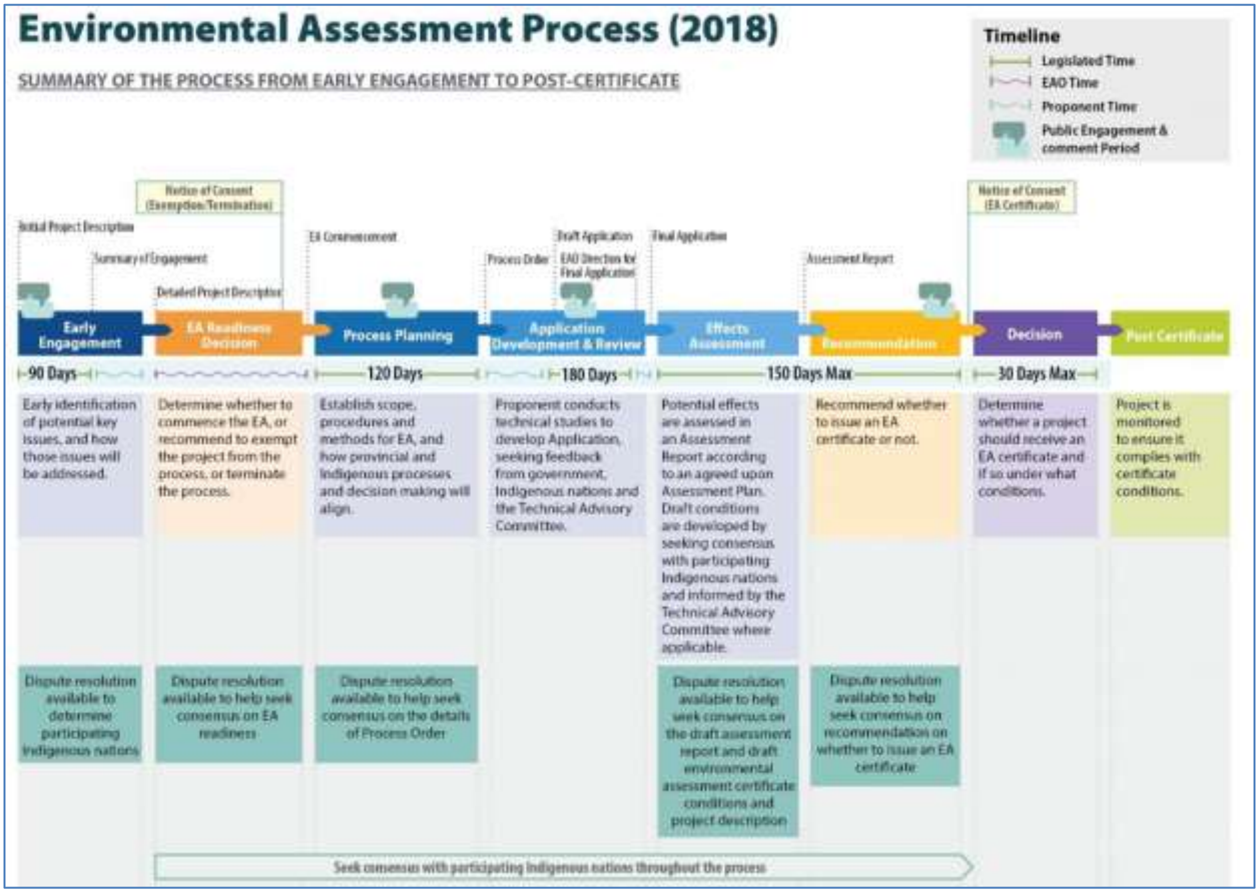
20.1 Please describe the regulatory process and associated time frame for completion of each stage of an EA, from early consultation to project approval, and compare this to the regulatory process for the same project if the pipeline would not trigger an EA.

Response:

The provincial environmental assessment (EA) process prescribed by the 2018 *Environmental Assessment Act* and associated regulations and guidance documents (depicted and described in detail available at the following link: https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/environmental-assessments/the-environmental-assessment-process/2018-act-environmental-assessment-process) includes five Environmental Assessment Office (EAO) led activities with a cumulative 570 day legislated maximum period (approximately 19 months) and two approval periods with no legislated time limit.

In addition to the approximately 19 month legislated period, there are two proponent-led phases of the EA process, Early Engagement and Application Development, which both require a substantial period of time to properly complete. FEI's experience, as confirmed by its consultants, is that it is appropriate to allocate at least 12 months for each of these items (approximately 24 months total).

Summary of the Process from Early Engagement to Post-Certificate[8]

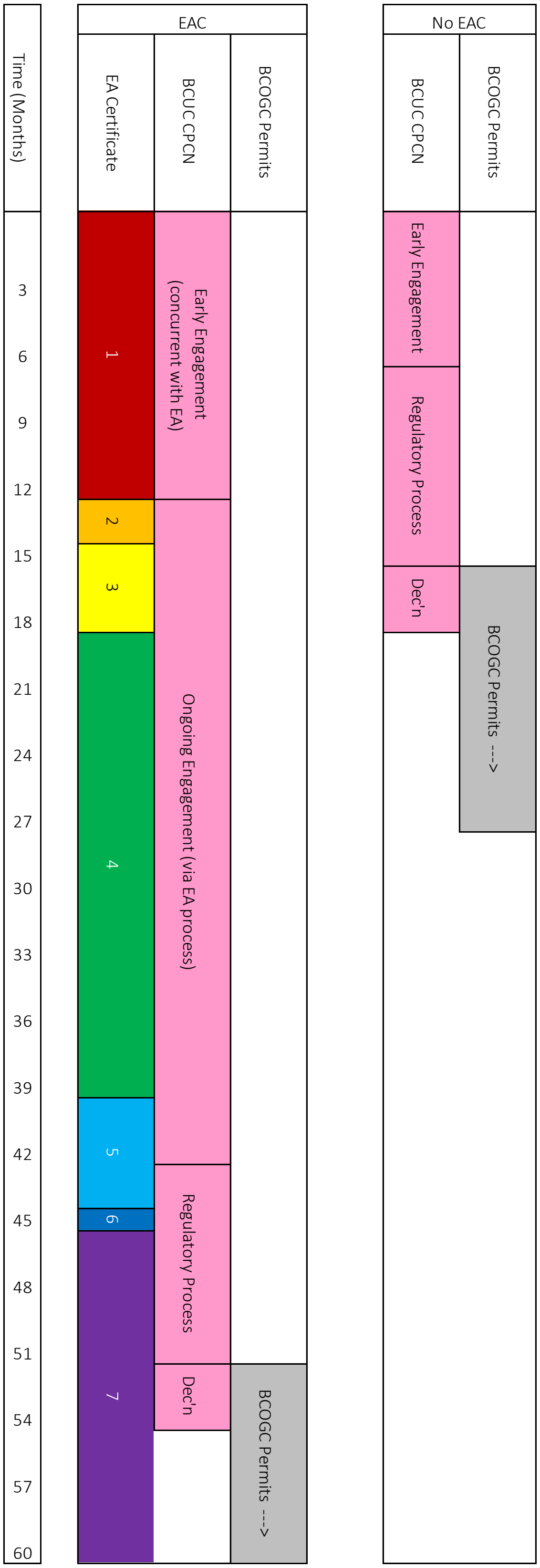


FEI notes that the combined legislated and proponent period is approximately 45 months (reflecting some periods of the process without legislated time limits). This schedule assumes that the various opportunities to obtain consensus with participating Indigenous communities proceed in a timely manner and that there are no events that lead the EAO, the proponent, or a participating Indigenous community to request a pause in timing to address a technical issue, undertake studies to collect additional data, clarify assessment findings, or resolve disputes related to process or lack of consensus.

Further, FEI provides a simplified regulatory process diagram below which compares a hypothetical linear pipeline project with and without an Environmental Assessment Certificate being required.

[8] EAO User Guide, Version 1.01. https://www2.gov.bc.ca/assets/gov/environment/natural-resource-stewardship/environmental-assessments/guidance-documents/2018-act/eao_user_guide_v101_march_2020.pdf.

Simplified Comparison of Linear Pipeline Project
(with and without an EAC)



LEGEND	
1	EA Early Engagement
2	EA Readiness Decision
3	EA Process Planning
4	EA Application and Review
5	EA Effects Assessement and Recommendation
6	EA Decision
7	EA Post Cerfiticate Activities (contingent on project)
8	BCUC CPCN Process
9	BCOGC Permit Process

1

Although simplified in the above diagram, BCOGC pre-permitting processes require further detailed engineering, preparation of environmental management plans, engagement with Indigenous groups and compilation of an application. Upon submission, BCOGC staff conduct in-depth technical review and carry out Indigenous consultation. Finally, the BCOGC makes a determination on the permit and informs affected land owners and Indigenous groups.

20.2 Please explain how FEI determined that the anticipated timeline for completion of an EA is three years.

20.2.1 Please compare FEI's anticipated timeline for completion of an EA with any legislated timelines within the Environmental Assessment Act or with any timelines proposed by the Environmental Assessment Office for the completion of an EA.

Response:

FEI's recent experience along with general guidance provided by external consultants, which takes into account the legislated timelines, suggests that, at minimum, it is possible to obtain an EA Certificate within three years although it typically takes longer. Please also refer to the response to BCUC IR1 20.1.

21.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.4.2.2, p.45

Alternative 5

On page 45 of the Updated Application, FEI states:

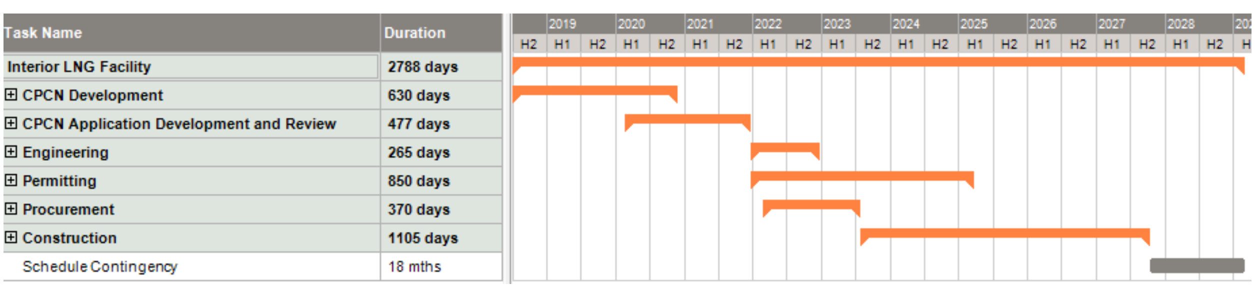
> Alternative 5 would meet the capacity objective for this project. However, preliminary research indicates that this alternative would be significantly too complex to design and construct prior to the winter of 2023/2024. An estimated minimum of five years is required to design and execute construction of such a facility following CPCN approval, pushing the completion date to 2027, or likely later.

21.1 Please describe the design and construction process and associated time frame for completion of each stage of Alternative 5, from early consultation to project commissioning.

<u>Response:</u>

A Level 1 schedule, reproduced below, shows how the timelines associated with Alternative 5 were not able to meet the Project need in time to address the capacity shortfall. Combined with the expected high-level costs (please also refer to the response to BCUC IR1 21.2), these led FEI to discard Alternative 5 early in the screening process. As such, further definition of the information requested is not available.

Please note that the "… minimum of five years…" mentioned on page 45 of the Update Application represents the beginning of the Engineering task through to the end of the Construction task in the Level 1 Schedule below, and assumes CPCN approval would occur in Q4 2021.



21.2 Please explain whether FEI had considered any additional benefits associated with on-system LNG storage that may be possible for Alternative 5.

21.2.1 If not, please explain why not.

21.2.2 If yes, please describe any studies FEI conducted and provide the results of these assessments.

Response:

Additional benefits associated with on-system LNG storage were considered early in the screening process, but no detailed studies of these potential benefits were undertaken due to reasons mentioned below.

The preliminary Class 5 estimate produced for the OCU Project (see Table 4-2 in the OCU CPCN Application, reproduced below) indicated that this alternative could be up to five times the cost of the least expensive alternative identified. As a result of this and the lengthy execution schedule (as discussed in the response to BCUC IR1 21.1) that indicated this alternative was not feasible in the timeline required, FEI did not undertake further investigation of this alternative.

Alternative	Description	Total Pipe Installed (km)	Capital Cost Estimate (2019$ Millions)
1	ITS Upgrades to VER PEN 323	15	40 to 100
2	Modified ITS Upgrades to VER PEN 323	19	50 to 130
3	OLI PEN 406 Extension	30	100 to 250
4	508 mm Loop from Savona	54	200 to 500
5	LNG Facility Near Vernon	n/a	250 to 600

22.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.1, p. 32; Section 4.6.1, p. 49

Asset Management Capability Alternative Evaluation

On page 32 of the Updated Application, FEI states that the OCU Project has the following project objectives:

1. Increase the delivery capacity of the ITS to meet peak demand requirements and to maintain safe and reliable gas service to FEI customers in the central and north Okanagan regions; and
2. Ensure all construction related activities are completed in time for the winter of 2023/2024 to avoid service interruptions to customers.

On page 49, FEI provides Table 4-5 which shows Asset Management Capability Alternative Evaluation criterion and associated weighting.

Table 4-5: Asset Management Capability Alternative Evaluation

Criterion	Weighting	Alternative 1: ITS Upgrades Score	Alternative 2: Modified ITS Upgrades Score	Alternative 3: OLI PEN 406 Extension Score
System Capacity Increase	50%	5	5	5
Operational Flexibility	50%	2	3	4
Weighted Total:*	**100%**	**3.5**	**4.0**	**4.5**

22.1 Please provide further details on FEI's OCU Project objective of increasing the delivery capacity of the ITS to meet peak demand requirements. For example, is the objective of the OCU Project to meet peak demand requirements in the winter of 2023/2024, winter of 2029/2030 or over the entire 20 year forecast period?

Response:

FEI's OCU Project objectives are both to construct a solution that can support the increased ITS peak demand requirements over the 20 year forecast period, and to ensure that the Project is completed in time for the winter of 2023/2024 to maintain safe and reliable gas service and avoid any service interruptions to its customers.

22.2 Please explain how FEI defines and measures "operational flexibility" in its Alternative evaluation.

Response:

Operational flexibility focuses on the additional options that an alternative provides FEI to deal with unexpected situations. This could include a greater ability to respond to pipeline emergencies, such as third-party, seismic, or hydrological damage, or undertaking maintenance activities while still allowing FEI to provide continuous delivery of safe and reliable energy.

Currently, gas supplied to the greater Kelowna region passes through the existing VER PEN 323 pipeline from Penticton towards Kelowna. In the Project area, the pipeline travels through urban, rural, mountainous, and agricultural land, and crosses multiple watercourses. Each of these environments expose the pipeline to potential risks that could result in damage, requiring a pressure reduction or pipeline shut-in.

A major driver to reducing this risk and providing operational flexibility is having multiple paths through which the gas can travel to its destination – also referred to as pipeline looping. By having multiple paths, some or all of the gas can still reach its destination should flow through one of the paths be reduced or shut off. Thus, alternatives that provide multiple routes for the gas to travel received higher operational flexibility scores:

- Alternative 1 would result in only a single path (the existing VER PEN 323), so any capacity reduction or outage would affect the entire line, limiting FEI's options in an emergency.
- Alternative 2 would result in looping of the area through Penticton, resulting in two paths for that part of the system: one that can carry the full required capacity (the new OLI PEN 406 extension), and one that can carry a portion of the required capacity (the old VER PEN 323). If a disruption to the OLI PEN 406 extension occurred during warmer or non-peak times, the old pipeline could still supply some or all of the required gas.
- Alternative 3 will result in looping the entire length, resulting in the same benefits as Alternative 2, but extending them over the entire length of the Project area, and not limited to the area around Mount Campbell.

22.3 Please discuss whether FEI considered including resiliency of the ITS as a criterion in its evaluation of alternatives.

22.3.1 If not, why not?

Response:

Yes, FEI considered including resiliency of the ITS but did not select it as one of the evaluation criteria for the reasons mentioned below.

In particular, FEI considered whether certain alternatives could increase the percentage of gas in the ITS sourced from the TC Energy system, thereby reducing FEI's reliance on the

Enbridge-owned Westcoast system. Reduced reliance on a single source increases a system's ability to manage supply in the event of a disruption to that source, improving resiliency. However, when compared against each other, none of the three feasible alternatives provided a significant change to the gas balance in the system and thus did not represent a considerable resiliency benefit. Additionally, all three feasible alternatives were nearly identical from a resiliency perspective. As such FEI determined that this was not a valuable metric for comparison.

Increasing the operational flexibility of the system provides FEI with an improved ability to shut in portions of its system either for planned work or if required for emergency response. Thus improved operational flexibility is tied to a corresponding improvement in system resiliency.

22.4 Please explain in detail FEI's rationale for the System Capacity Increase weighting of 50 percent, given that the primary objective of the OCU Project is to meet peak demand requirements.

Response:

FEI's alternative evaluation followed a two-step process. Alternatives were initially screened against the Project objectives, which included an increase to the ITS capacity to meet forecast peak demand requirements and to ensure that the Project is completed in time for the winter of 2023/2024 to avoid service interruptions to customers.. Essentially, for an alternative to meet Project objectives, it was required to provide sufficient transmission pipeline capacity for the 20-year forecast period (assuming necessary compression upgrades could be completed as required). Thus, any project alternative which passed initial screening was capable of providing the minimum required capacity benefit to the system.

The System Capacity Increase criterion would place a higher value on alternatives which provided a greater capacity increase above and beyond the minimum threshold set by the primary Project objectives. However, since all feasible alternatives which passed initial screening provided a similar capacity increase to the system, all three received the same score.

Since the requirement set by the first step of the evaluation process guaranteed a sufficient capacity benefit, FEI's team agreed that any additional capacity increase is of equal value to increases in operational flexibility.

22.5 Please discuss how the Asset Management Capability Alternative Evaluation criterion and associated weighting were determined.

<u>Response:</u>

The evaluation criteria and associated weightings were developed by an internal team of FEI subject matter experts, including representatives from the Asset Management, Engineering, Project Management, Regulatory Affairs, Community and Indigenous Relations, Environmental Management, and Property Services departments.

All parties considered which evaluation criteria were the most important from their perspective, using a template of proposed evaluation criteria to record their input. A workshop was then held to incorporate input from experts in each individual group to determine a set of evaluation criteria and associated weightings for the OCU Project. This provided the basis for the evaluation criteria and weightings selected. Evaluation criteria were further refined as the Project progressed and the Project team's understanding of the specific needs of the Project improved.

22.6 Please discuss whether FEI applies the criterion and associated weighting shown in the preamble to its other capacity upgrade projects.

22.6.1 If not, please provide the Asset Management Capability Alternative Evaluation criterion and associated weighting FEI used in other capacity upgrade projects.

<u>Response:</u>

FEI has not had any recent major projects that were capacity driven. Other recent major projects have been driven either by integrity concerns, third-party work, or resiliency.
As such, for each major project, FEI defines the key drivers and impacts of a project and, comparing it to representative past projects that FEI has undertaken, identifies the evaluation criteria to further assess feasible project alternatives. FEI deliberately limits the number of criteria for a given project to ensure that the key drivers to decision making are not diluted by less applicable criteria.

23.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.6.2.2, p. 53

Alternative 1 & 2 – VER PEN 323 retesting

On page 53 of the Updated Application, FEI states:

> Testing this pipe to a significantly higher level of stress than in 1957 leads to uncertainty about FEI's ability to successfully carry out the requalification tests. This presents a significant scheduling risk to the implementation of Alternative 1 or Alternative 2. Retesting promotes opening of existing cracks that are near failure so that they fail during the test and can be removed from the system. However, to complicate matters, it may also promote growth of small cracks that would have otherwise been acceptable, resulting in a new set of critical cracks left in the system after completion of the repairs. These new critical cracks may fail during the subsequent attempt at a successful test, resulting in a cycle of leak detection, repair and testing.

23.1 Please confirm whether FEI is able to conduct inline inspections on the VER PEN 323 pipeline.

23.1.1 If confirmed, please discuss the overall integrity of the VER PEN 323 pipeline based on the inline inspection results.

Response:

FEI is able to conduct in-line inspections (ILI) on the VER PEN 323 pipeline to locate and size imperfections including geometric (e.g., dents, wrinkles, and buckles) and metal loss (e.g., corrosion and gouges) features. FEI is not currently able to conduct ILI on the VER PEN 323 pipeline to identify cracking imperfections, but is developing the ITS Transmission Integrity Management Capabilities (TIMC) project to make the necessary system and pipeline alterations to allow the use of crack detection tools (FEI anticipates to file this application in 2022).

FEI interprets the term "overall integrity" as referring to FEI's knowledge of the entire VER PEN 323 pipeline based on its condition monitoring activities, which include an assessment of known time-dependent threats of corrosion and cracking. FEI's assessment of the overall integrity of the VER PEN 323 pipeline, based on current knowledge, is that it is suitable for continued service and that with current and planned ongoing integrity management activities it will remain appropriate for safe and reliable operations.

FEI's current integrity management activities identified geometric and metal loss imperfections on the VER PEN 323 pipeline. These known imperfections on the VER PEN 323 pipeline are managed through recurring ILI and associated integrity dig activities, supplemented by site-specific repairs where required. ILI is an industry-preferred integrity management methodology as it enables operators to mitigate the potential for rupture and leak failures and supports active and proactive monitoring of ongoing threats. ILI also provides cost-effective integrity management because it identifies imperfections or defects at site-specific locations that can be repaired, reducing the need for large-scale and costly system-level pipeline rehabilitation efforts (such as pipeline replacement).

FEI's current integrity management activities have also identified cracking imperfections on the VER PEN 323 pipeline through opportunity digs. However, due to the limited lengths of pipe that have been exposed relative to the full length of buried pipelines, the opportunity digs are not expected to have identified all cases of cracking.

23.2 Please discuss FEI's assessment of the likelihood that the VER PEN 323 pipeline has "existing cracks that are near failure so that they fail during the test."

Response:

FEI believes there is a reasonable likelihood that the VER PEN 323 pipeline has "existing cracks that are near failure so that they fail during the test". As such, OCU Project alternatives that would involve re-hydrotesting have been appropriately evaluated with a low score of 1. This evaluation is based on:

- FEI's observations of cracking imperfections on the VER PEN 323 pipeline during previous opportunity digs;
- Knowledge of the original pressure test being limited to 110 percent of the design pressure in accordance with the industry standard in 1957 (and not the current standard of 125 percent); and,
- An industry-recognized potential for crack-like imperfections in seam welds on vintage pipelines (i.e., pipelines constructed prior to 1970).

D. PROJECT DESCRIPTION

24.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.6.1, p. 78

Project delivery method

On page 78 of the Updated Application, FEI states:

> Given the scale and scope of the Project, FEI will use a project delivery method that utilizes separate contracts for engineering design, construction management and inspection, and construction. The engineering design will be completed using a services contract for the complete design and development of bid packages. These bid packages will then be used to seek competitive pricing from contractors for the construction of the works.

24.1 Please discuss whether FEI has used the selected project delivery method for other projects of this scale and scope.

Response:

FEI has successfully used a design-bid-build (DBB) project delivery method that utilized separate contracts for engineering design, construction management and inspection, and construction on the Inland Gas Upgrades (IGU), and a similar design-bid-build approach that utilized separate contracts for EPCM (Engineering, Procurement and Construction Management) and construction on two other projects, the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU), and the Coastal Transmission System (CTS). These three gas line projects are of similar scale and share similar characteristics but the specific scope of each project is unique and was required to address a particular need.

24.1.1 If no, please explain the rationale for the selection of the OCU Project delivery method.

Response:

Please refer to the response to BCUC IR1 24.1.

24.1.2 Please discuss the pros and cons of the selected delivery method with respect to the allocation of risks related to cost escalation and schedule between FEI and its consultants or contractors.

Response:

In a DBB delivery method, the risk for design is allocated to the designer and the risk for construction is allocated to the contractor. The following table highlights the pros and cons of the DBB delivery method as it relates to cost escalation and schedule.

Cost Escalation	
Pros	***Cons***
• In DBB the design is completed to 100 percent prior to bid, so the risk of cost escalation due to change orders requiring design changes during construction is minimal. • The DBB delivery method is a well established and widely used method to deliver pipeline projects that do not have a schedule constraint or other major execution risks, so the risk of cost escalation, if contractor's input is not incorporated, is minimal as in other alternate delivery methods. • There are no major technology risks with the Project, so the likelihood of cost escalation due to errors and omissions that arise from the completed design are minimal. • FEI and the design firm have a better understanding of the permit requirements to commence the works for the Project, so there is minimal cost escalation risk due to notice of works permits in this method. • 100 percent design allows FEI to completely investigate site conditions and include those findings in the design and tender documents thereby minimizing the risk of differing site conditions cost escalation and change orders.	• Because the contractor had no input into the design, the risk of cost escalation due to change orders that result from design changes increases during the execution phase. • Since the contractor had no input on constructability during design, there is a possibility of cost escalation to address constructability issues and site conditions during execution. • There is a risk that some municipal permits require contractor input that if not addressed before contract start could cause cost escalation. • A contractor may have a better means and method to address certain site conditions which if not accounted for in the design, may cause a cost escalation by requiring a design change.

Schedule	
Pros	***Cons***
• Once the design is 100 percent completed the contractor takes responsibility to complete the work on an agreed to schedule within a specified time, subject to certain exceptions that allow for an extension of time, meaning there is little risk to the contracted schedule completion date. • The designer has the opportunity to include all known requirements in the design minimizing the risk to schedule impacts during construction - although there could be some minor schedule impact while design is being finalized to obtain as much site information as possible. • All permits can be applied for before construction commences reducing the impact to the schedule.	• If the constructability issues result in significant modification to the design, the contractor's extension of time request can be lengthy causing a schedule delay that may be addressed by having the contractor accelerate works but at a cost to FEI. • Some permits may benefit from contractor's knowledge and not having contractor input can delay the start date for site activities. • Certain site conditions may benefit from contractor input and if not considered could cause minor schedule delay.

A DBB delivery method is suitable for the OCU Project because there is sufficient time available to complete the engineering design, then bid and award the construction contract and meet the schedule. The DBB delivery method also provides FEI the ability to tender the construction work package after design risks are mitigated and addressed in the design package.

25.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.4.2.8, p.72

Water Crossings

On page 72 of the Updated Application, FEI states:

> All pipeline crossings within the Project will be constructed using open cut methods with the exception of Penticton Creek. In general, the types of crossings identified along the proposed OLI PEN 406 pipeline route include:
>
> - Road Crossings;
> - Water Crossings; and
> - Pipeline and Utility Crossings.

25.1 Please identify all Water Crossings along the proposed OLI PEN pipeline route.

Response:

Please refer to Attachment 25.1 for a list of all water crossings along the proposed OLI PEN 406 pipeline route.

25.2 Please describe the construction methods FEI considered for each Water Crossing along the OLI PEN pipeline route and explain the primary reason(s) for choosing the proposed crossing method.

Response:

FEI considered several crossing methods for water crossings along the OLI PEN 406 extension route during the 30 percent design stage of the Project. Other than Penticton Creek, FEI has identified that all water crossings will be crossed using an open trench method. Open trench construction through water crossings is the traditional installation method for pipelines in less sensitive environments where construction space is not constrained. During detailed design, alternative crossing methods such as trenchless methods may be chosen for selected water crossings in consultation with the environmental consultant and Indigenous groups.

Open trench water crossing construction is commonly planned in conjunction with a dam and pump dewatering method while trenchless crossing construction is commonly planned using HDD or boring. The tables below illustrates the advantages and disadvantages of each type of crossing construction method.

Crossing Method Analysis – Open Trench

Advantages	Disadvantages
• **Cost** – Open trench construction requires minimal specialized equipment, typically a smaller crew and easier design philosophy resulting in a lower cost impact compared to a trenchless construction method. • **Schedule** – Commonly available equipment (excavator) and high constructible design result in a quick installation process, reducing the overall crossing construction duration. • **Operations and maintenance** – The pipeline is located close enough to the surface such that it can be excavated in the future should the need occur.	• **Environmental** – An Environment Impact Assessment is required to be completed in accordance with the environmental codes and recommended guidelines. • **Schedule** – Depending on aquatic habitat findings (e.g., fish spawning/migration, food supplies, silt build up, etc.) short timing windows could be enforced, thus limiting the construction window. • **Construction** – Isolation and de-watering techniques may be required.

Crossing Method Analysis – HDD

Advantages	Disadvantages
• **Environmental** – No instream / riparian zone work, as minimal impact to the water body occurs (under normal conditions). • **Schedule** – More flexible construction timing window. HDD can avoid congested or environmentally sensitive areas, if properly completed. • **Operations and maintenance** – Pipe located at a lower depth of installation can limit future risks associated with exposure from scouring during freshet. • **Routing** – HDD can reduce construction challenges leading up to water crossings. For example, an HDD method could be used in relation to existing utility infrastructure, nearby road crossings, and avoid construction on steep slope embankments.	• **Cost** – Requires specialized equipment and skilled workers, hence the use of trenchless crossings is typically more expensive than open trench excavation. The drilling process must be continuously monitored and controlled, requiring highly skilled operators. • **Crew Resources** – Acquiring and scheduling the specialized equipment, materials, and crew could cause scheduling complications (longer lead times or lower availability). • **Environmental** – Drilling in soft or shallow soil areas increases the risk of drilling fluid being released into the waterway. • **Failure Risk** – HDD activities have an inherent risk from uncertain subsurface conditions along the drill path, which increases cost and schedule risks due to potential failed attempt(s).

26.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.6.5, p.79; Section 5.10.4.4, p.90

Penticton Creek Horizontal Directional Drill (HDD) Installation

On page 79 of the Updated Application, FEI states:

> The main objective of the early works construction phase is to complete the HDD [horizontal directional drill] work. While the feasibility study concluded that HDD is a feasible option to cross Penticton Creek, there is still a risk that the HDD installation could be unsuccessful. FEI plans to address the risk as soon as possible in the Project to allow adequate time to implement the contingency plan of using an open trenching method across the drainage within the mainline contractor’s scope of work.

On page 90, FEI explains:

> There is a high risk to the Project should the HDD fail, as the contingency plan consists of attempting a subsequent drill, and failing that the plan is to open trench across a very steep ravine. FEI and SMCI have identified an open trench route across Penticton Creek and this option is currently under evaluation. FEI will proceed with the design and permitting of both the HDD and the open trench options to minimize delays should the HDD prove not feasible. Table 5-12 outlines the range of possible outcomes stemming from an unsuccessful HDD across Penticton Creek.

26.1 Please provide details of any construction challenges with the proposed Penticton Creek HDD installation and explain how these challenges factored into FEI’s decision to complete the HDD as part of its early works construction phase.

<u>Response:</u>

As explained in section 5.10.4.4 of the Updated Application:

> The preliminary feasibility assessment completed by TerraHDD, a company specializing in HDD concluded that the Project could drill a path under Penticton Creek. HDD at this location minimizes stakeholder and environmental impacts and is the lowest cost option for the Project. Significant geotechnical work was undertaken to evaluate the feasibility of HDD but there is always uncertainty remaining as most of the subsurface conditions along the drill path cannot be fully assessed. Therefore, the success of HDD is not realized until the drilling is complete and the pipe is pulled into the hole.

The preliminary geotechnical feasibility assessment was made based on an intensive desktop study, a field drilling investigation program including four deep exploration holes, and a geophysics survey for the contemplated HDD area. The assessment indicated that installation of the pipe via HDD is feasible, but there are construction risks associated with the geotechnical conditions in this area. These conditions include the presence of highly fractured rock, rock formations that vary significantly in their strength, and a thick overburden of sandy and gravely soils with cobbles and boulders. In addition to the risks associated with these conditions, there is subsurface risk associated with the unknown ground conditions, which is an inherent risk to any HDD project, especially those with a long drilling path. Such risk arises from the fact that it is not possible, within practical economic limits, to have a detailed geotechnical characterization of each and every soil and rock formation along the HDD drilling path.

FEI scheduled the HDD to commence during the early works phase primarily for the following two reasons:

1. The design, permitting and various plans required to complete the HDD are mostly independent from the mainline activities and can easily be advanced during the detailed design phase to advance construction activities.
2. Completing the HDD early in the Project will allow FEI to confirm the risk and better position the Project for future works. If the HDD is not successful, FEI will have sufficient time to properly plan and implement the contingency plan (open trench construction).

While FEI indicated in the Updated Application that an HDD is the preferred option across Penticton Creek, that may change during detailed design. If the open trench option proves more feasible than the HDD during detailed design, FEI may proceed with an open trench cut as the preferred option, with the HDD as the contingency plan.

26.2 Please discuss any potential environmental and public impacts associated with an HDD failure.

Response:

There are two potential failure mechanisms associated with HDD construction: failure to successfully complete the HDD bore, or an inadvertent release of drilling fluid to the environment during drilling. The potential environmental and public impacts for each are explained below. FEI would not expect any of the impacts to result in long-term harm to the public or environment, as mitigation measures will be utilized to address outcomes from potential HDD failures.

For an HDD bore failure, there is potential for surface water to infiltrate the ground water through the conduit created by the abandoned drill hole. The potential environmental impact associated with this failure is a change to local hydraulic conditions and ground settling if the hole were to collapse. This potential environment impact would be mitigated by filling the drill hole with grout as described in the response to BCUC IR1 26.3. Additionally, if the HDD is unsuccessful and open trench construction is required, in-stream works would be required to install the pipe across Penticton Creek.

For an inadvertent release of drilling fluid to the environment, the potential environmental impacts are drilling fluid pooling on land and/or drilling fluid being released to Penticton Creek. Drilling fluid, a mixture of bentonite clay and water, is considered chemically benign, however due to its small particle size, releases to an aquatic habitat have the potential to harm fish and other organisms. In this situation, FEI would mobilize cleanup crews to collect drilling fluid releases and restore impacted habitat.

While there are potential environmental and public impacts associated with an HDD failure, the benefits of a successful HDD are that the environmental and public impacts are minimized compared to an open trench cut. For HDD work taking place on the Project, FEI will conduct a thorough feasibility assessment to understand the probability of success before attempting an HDD and, as noted earlier, will utilize mitigation measures to address the outcomes of an HDD failure.

26.3 Please describe how the drill hole would be abandoned if HDD installation is unsuccessful and quantify any associated abandonment costs.

Response:

Should the HDD installation be unsuccessful and the drill attempt need to be abandoned, FEI would complete appropriate activities to abandon the HDD. The driller would remove any accessible materials from the site and fill the drill bore with grout in stages to limit impact to the environment by way of inadvertent release through fractures. This abandonment process would limit any future impacts to the environment and public by limiting collapse and non-natural water channels for surface or ground water.

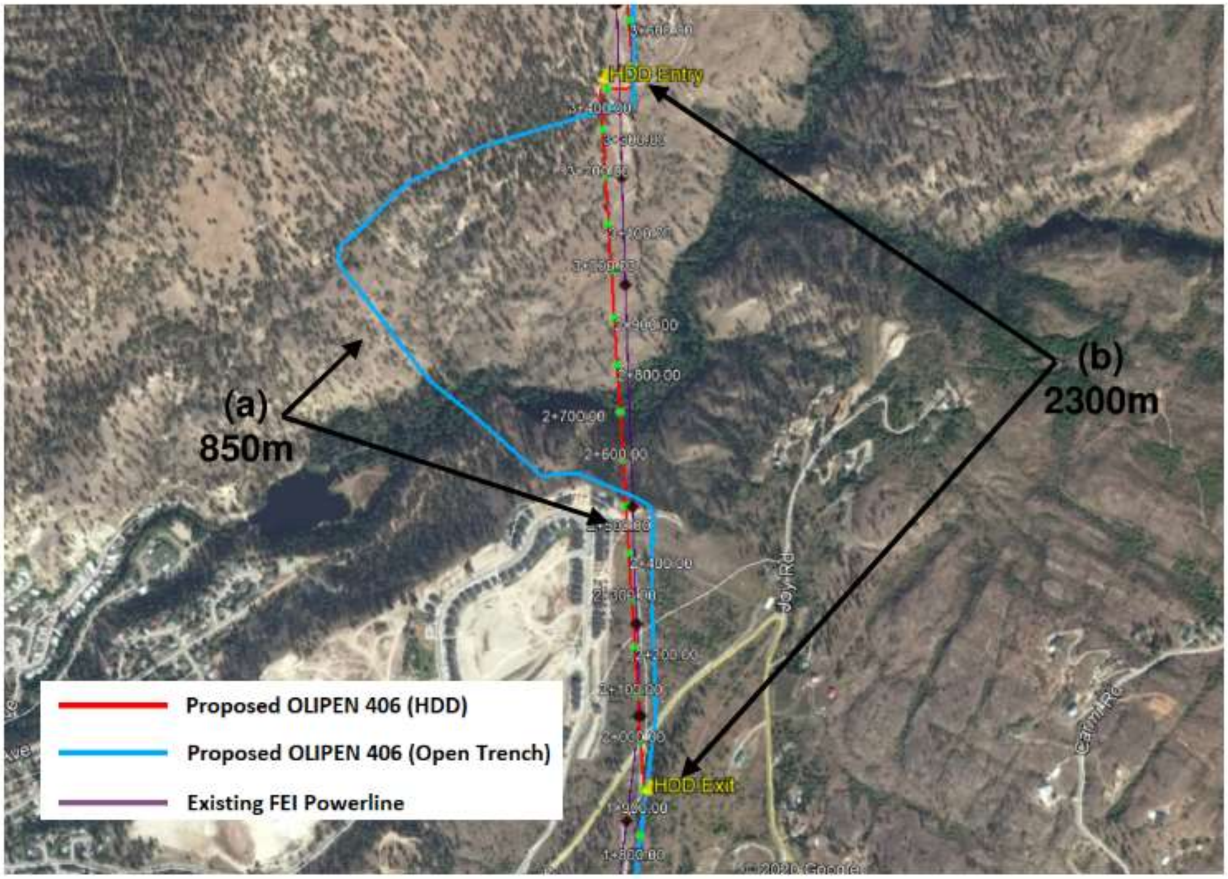
The associated abandonment costs are estimated to be approximately $650 thousand.

26.4 Please discuss any changes to the pipeline alignment crossing Penticton Creek should the HDD fail.

Response:

FEI is actively developing an alternate route alignment that would use a conventional open trench crossing of Penticton Creek should the HDD crossing be determined not feasible during detailed design, or if the HDD fails during construction. FEI completed preliminary route selection for the alternate alignment during the Class 3 cost estimate phase. The preliminary route is shown in the figure below.

Alternate Open Trench Crossing of Penticton Creek



The proposed alternate alignment construction would utilize open trench excavation and installation for the entire length. Although the open trench crossing alignment measures approximately 850 metres from crest to crest, the actual pipeline length is approximately 2,300 metres.

27.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, p. 82

Kettle Valley Rail Trail

On page 82 of the Updated Application, FEI states:

> The Kettle Valley Rail Trail (KVR) is a national historical site located in Naramata and runs in parallel with some sections of the OCU Project route. The KVR is a popular among cyclists who want to bike from Naramata to Kelowna. As such, FEI has recognized the importance of this historical site in its Project planning.

27.1 Please provide a summary of any permits or land access agreements which will be required for any segments of the OLI PEN 406 proposed pipeline that cross or run parallel to the KVR.

<u>Response:</u>

In addition to applying to the BCOGC for a pipeline construction permit, FEI will apply to the Recreation Sites and Trails BC (RSTBC) branch of the Ministry of Forests Lands Natural Resource Operations and Rural Development (MFLNRORD) for an authorization under section 16 of the *Forest Recreation Regulation* under the *Forest and Range Practices Act* to conduct Project related activities within the proximity of the KVR Trail.

In 2020, FEI began engaging with the RSTBC branch of MFLNRORD to confirm the permit application requirements. The Project team is currently compiling the deliverables for the application. The application submission is anticipated in Q2 2021 with approval anticipated by late Q4 2021.

27.1.1 Please provide an update on the status of these permits or land access agreements.

<u>Response:</u>

Please refer to the response to BCUC IR1 27.1.

27.1.2 Please discuss the risk of delay to the Project Schedule due to permitting regarding the KVR.

Response:

There is a low risk of delay to the Project schedule due to permitting regarding the KVR. FEI has commenced the compilation of the permit application requirements as described in BCUC IR 27.1 and plans to submit it in Q2 2021. The permit approval process is expected to take approximately six months and is expected to be obtained in time for construction start in Q4 2021. In the unlikely event the permit approval process takes longer, FEI's contingency plan is to commence work in other areas that do not require a permit from the KVR authority.

28.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.9.6, p.85

Other Pending or Anticipated Application/Conditions

On page 85 of the Updated Application, FEI states that it "expects the Project will not require an Environmental Assessment Certificate under the BC Environmental Assessment Act."

28.1 Please explain why FEI expects the OCU Project will not require an Environmental Assessment Certificate.

Response:

The BC *Environmental Assessment Act* and the Reviewable Projects Regulation state that natural gas transmission pipelines that meet the following relevant guidelines are reviewable projects:

- A project with diameter of greater than 323.9 mm (12.75 inches) and a length of 40 km or greater, if the land on which the pipeline is built is not alongside and contiguous to an area of land previously for a transmission line, transmission pipeline, public highway or railway, or
- If the project would meet the threshold if the threshold was reduced by 15 percent (i.e. 34 km)

Despite having a diameter of 406 mm (16 inches), the total length of the preferred alternative is 30 km, and approximately 80 percent parallels existing linear corridors such as existing electric and gas rights of way and roads. Therefore, the preferred alternative for the OCU Project will not require an Environmental Assessment Certificate.

28.2 Please discuss the potential impact to OCU Project schedule if an Environmental Assessment Certificate is required.

Response:

FEI's expectation is that the Project would be delayed by approximately three years if an Environmental Assessment Certificate was required for the OCU Project.

29.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.10.4.4, p. 90

Market risk

On page 90 of the Updated Application, FEI states, "FEI identified that there is a market risk to the Project due to factors such as contractor capacity, the availability of qualified pipeline contractors in 2022 and 2023 and market risk where bids are uncompetitive."

29.1 Please elaborate on the information or experience FEI relied upon in identifying this market risk.

<u>Response:</u>

FEI relied on a check estimate prepared by Innovative Pipeline Projects Ltd., Calgary AB, to understand the uncertainty in the market risk associated with contractor capability and availability when the OCU Project is planned to be constructed in 2022-2023. Since the check estimate suggested that there could be an uplift in bid prices, FEI undertook a reserve risk analysis to address the uncertainty and included an amount as a management reserve in the unlikely event the market risk materializes.

29.1.1 Please explain whether FEI has re-evaluated the market risk since its initial risk analysis. If yes, please discuss any changes to market risk. If not, why not.

<u>Response:</u>

FEI has not formally re-evaluated the market risk beyond what was submitted in the Updated Application. Management of risk is a continuous process throughout a project's lifecycle and FEI continues to monitor all the Project risks, with treatment applied as appropriate. A treatment currently being applied is FEI's continuous engagement with contractors for all projects within the Major Projects portfolio. This will enable FEI to identify early any changes to contractor capacity and availability. With respect to a re-evaluation of risks (termed risk quantification), this is ordinarily done at a phase gate or key milestones or if a significant event or threat is identified during risk monitoring. Currently, FEI plans to re-evaluate the market risk at the design completion milestone scheduled for August 2021.

29.2 Please explain what impact the identified market risks may have on the OCU Project schedule.

Response:

There is no schedule impact associated with the market risk, as it is purely a financial risk.

29.2.1 Please discuss whether any risks to the OCU Project schedule are accounted for in the assessment of the Management Reserve amount. If so, how?

Response:

The risks to the OCU Project schedule are not accounted for in the Management Reserve. The Management Reserve in the Updated Application is a dollar amount to cover the likely cost impacts should bids be higher than the Class 3 estimate. This impact is funded as a cost Management Reserve because should the risk materialize, the magnitude of the impact would consume the Project's contingency and thus the risk cannot be effectively managed using contingency. The risk impact to the schedule is mitigated as described in the response to BCUC IR1 29.2.

30.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.4.4, p. 74

Pipeline Deactivation

On page 74 of the Updated Application, FEI states:

> A 1,200 m section of the existing OLI PEN 406 will be deactivated between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station.
>
> This will include removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line and maintaining a low pressure blanket with nitrogen.
>
> Deactivation of this section of OLI PEN 406 was chosen over abandonment to minimize ecological and socio-economic disturbance to the area and allow re-establishment of gas supply to the Ellis Creek Pressure Control Station if required in the future to support forecast peak demand beyond the 20 year planning window. Deactivation will follow all regulatory and code requirements.

30.1 Please confirm, or explain otherwise, that, after the deactivation of this section of OLI PEN 406, this portion of the assets will also be removed from FEI's ratebase.

Response:

Not confirmed. As described in the response to BCUC IR1 30.5, FEI requires the ability to reactivate this pipeline section as part of future integrity management activities. The value to FEI of the right-of-way and pipeline is significant as it provides flexibility for integrity management activities for no incremental cost.

The BCUC in its Decision and Order G-246-20, dated October 5, 2020 on BC Hydro's F2020 to F2021 Revenue Requirements Application approved for inclusion in BC Hydro's rate base the costs of the West End Vancouver Purchase (the East End Vancouver Land Purchase was approved in the BC Hydro F2017 to F2019 RRA Decision) which was to advance two substation construction projects. In reaching its decision, the BCUC Panel referenced a previous BCUC decision regarding the Waneta Dam transaction:[9]

> In the Waneta Decision, the BCUC, identified two exceptions to the Used and Useful principle set out above, namely that assets which are not currently physical (sic) used and useful in utility service may still be "Used and Useful", and therefore included in rate base, if they are "expected to be used in the reasonably foreseeable future", or if a portion of the asset is needed now, and the remainder "may not be needed for quite some time."

[9] Page 91. Also refer to BCUC Order G-130-18, BCUC Decision to the BC Hydro Waneta 2017 Transaction Application, page 71.

30.2 Please provide the amount of depreciation remaining to be recorded on this section of pipeline and the remaining useful life of the asset.

Response:

The asset value, accumulated depreciation, and net book value of the OLI PEN 406 pipeline, and the portion of the 1,200 m section that is to be deactivated is provided in the following table.

		$000's		
Length	**Particulars**	**Acquisition Value**	**Accumulated Depreciation**	**Net Book Value**
	OLI PEN 406mm Pipeline			
	Land Rights	$2,298	$176	$2,122
31.873km	TP Transmission Mains	33,261	15,369	17,892
	Total	$35,559	$15,545	$20,014
	Deactivated Portion			
	Land Rights [1]	$18	$1	$17
1.2km	TP Transmission Mains	1,252	599	653
	Total	$1,270	$600	$670

Note:

[1] *Allocation based on Deactivated Portion = Acquisition Value / Total Land Rights Acquisition Value x Accumulated Depreciation ($18 / $2,298 x $176)*

The actual remaining useful life is dependent on the ongoing condition of the pipeline. However, FEI's 2017 Depreciation Study filed and approved with FEI's Multi-year Rate Plan sets the average service life for transmission mains as 65 years. The OLI PEN 406 pipe was installed in 1994 and by the end of 2023 this line will have been in service for 29 years leaving an additional 36 years of financial service life (65 – (2023 – 1994) = 36). However, the actual life of a pipeline is dependent on the ongoing condition of the line and the continuous effectiveness of FEI's integrity management activities which can extend a pipeline's life beyond 65 years.

30.3 Please provide the costs of deactivation and on-going maintenance of OLI PEN 406.Please discuss the ecological and socio-economic disturbance to the area that would occur if the pipeline was abandoned.

Response:

The deactivation costs for the 1,200 m section of the existing OLI PEN 406 are approximately $80 thousand. This will include removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line, and filling it with a low pressure blanket of nitrogen.

Annual ongoing maintenance costs of the deactivated section of the existing OLI PEN 406 are approximately $3.5 thousand per year. This segment of pipe would be managed under applicable FEI standards and guidelines including right-of-way patrol and inspections, vegetation management, third-party driven inspections, nitrogen blanket pressure inspection and calibration, and cathodic protection testing and maintenance.

Abandonment of the proposed deactivated section of the existing OLI PEN 406 would imply the permanent removal from service of the 1,200 m pipe segment. Consistent with industry standard practice, FEI abandonment specifications require excavation, cutting, and capping every 200 metres along the abandoned pipeline section and includes grout filling of the entire length.

The abandonment process for the section of the existing OLI PEN 406 would have the potential to disturb contaminated soils in and around the industrial parks located along Okanagan Avenue, potential archaeological sites, and disturbance to sensitive creek crossings. It would also negatively impact some local businesses, as the OLI PEN 406 traverses several industrial parks and the excavation work required to support the abandonment process could impede their operations.

30.4 Please clarify whether FEI undertook an assessment of the costs associated with deactivating this section of pipeline compared to abandonment.

30.4.1 If yes, please provide the financial assessment.

30.4.2 If not, please explain why no assessment was undertaken.

Response:

FEI undertook development of scope of work and cost estimates for both deactivation and abandonment of the section of OLI PEN 406 pipeline.

The scope of work for abandonment would follow FEI abandonment specifications and is consistent with industry standard practice. At the tie-in location, a four metre section of pipe would be removed and a cap welded onto the abandoned section. At the Ellis Creek Pressure Control Station, a section of the OLI PEN 406 pipe would be removed from the road edge to the station facilities and a cap welded onto the abandoned section. 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). The site would be restored consistent with preexisting conditions. For the 1,200 metre section of the existing OLI PEN 406 line, approximately five sites would require excavation. FEI has estimated the costs associated with abandonment of the section of pipe to be approximately $200 thousand.

The scope of work for deactivation would be much more simple and consists of removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line, and maintaining a low pressure blanket with nitrogen. The costs associated with deactivation of the section of pipe are approximately $80 thousand.

30.5 Please discuss under what circumstances that FEI would reactivate this section of the OLI PEN 406 pipeline.

Response:

FEI is currently developing the Interior Transmission System (ITS) Transmission Integrity Management Capabilities (TIMC) project application to identify and address cracking threats on the ITS pipelines and intends to file it in 2022. One of the pipelines of potential concern is the VER PEN 323, including the section between the Ellis Creek Pressure Control Station and the proposed Chute Lake Pressure Control Station.

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.

30.6 Please explain the factors that could cause FEI to consider abandonment of the deactivated pipeline in future.

Response:

At this time, FEI has no reason to believe it would abandon the deactivated pipeline in the future.

31.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-2, Section 5.10.4.3, pp. 90–92

Contingency Estimate

On page 91 of the Updated Application, FEI states, “Contingency is normally funded at the P50 confidence level. Based on FEI’s risk tolerance, the Project contingency will be $25.1 million (13 percent) at the P50 confidence level.”

On page 90 of the Updated Application, FEI provides the following table showing the results of the Monte Carlo analysis:

Figure 5-6: Quantitative Risk Analysis - Monte Carlo Simulation

Base Estimate:	$187,960	Currency:	$CAN
Probability of Underrun	Indicated Funding Amount	Contingency	
		Costs (thousands)	Percent of Base Est.
5%	171,500	(16,500)	-9%
10%	179,500	(8,500)	-5%
15%	185,200	(2,800)	-1%
20%	190,100	2,100	1%
25%	194,800	6,800	4%
30%	198,700	10,700	6%
35%	202,400	14,400	8%
40%	206,100	18,100	10%
45%	209,700	21,700	12%
50%	213,100	25,100	13%
55%	217,000	29,000	15%
60%	220,400	32,400	17%
65%	224,400	36,400	19%
70%	228,400	40,400	21%
75%	233,200	45,200	24%
80%	238,600	50,600	27%
85%	244,700	56,700	30%
90%	252,900	64,900	35%
95%	265,000	77,000	41%

31.1 Please discuss how FEI determined the P50 confidence level to be the appropriate contingency for the OCU Project.

Response:

The rationale for selecting a P50 level of confidence is consistent with the AACE definition for contingency and aligns with the industry practice for contingency funding, which was confirmed by a leading industry expert.

FEI engaged Validation Estimating LLC (John Hollmann), to conduct a risk analysis, to develop a contingency estimate, and to confirm the reasonableness of FEI’s selection of contingency at the P50 level of confidence for the Project. Mr. Hollmann concluded in the memo provided as Confidential Appendix C-4 to the Updated Application, page 2, the following:

> In summary, a decision by FEI to fund contingency and escalation at the p50 confidence level is appropriate. Also, funding one of the two identified low probability/high impact risks at a p70 confidence level as a management reserve, in particular the risk event with the greatest potential impact, is prudent without being overly cautious.

In summary, the choice of a P50 level of confidence aligns to industry practice, was confirmed by a leading industry expert, and is appropriate to establish a contingency amount. As such, a higher confidence level was not considered.

31.2 Please explain whether FEI considered any alternative confidence level, other than the P50 confidence level.

31.2.1 If yes, please discuss the alternative(s) considered by FEI, including the advantages and disadvantages of each and please explain why each alternative was rejected.

31.2.2 If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 31.1. FEI engaged a leading industry expert to confirm the reasonableness of FEI's selection of contingency at the P50 confidence level. FEI did not consider funding contingency at any other confidence level.

On page 91 of the Updated Application, FEI states:

> The probability of both management reserve risks occurring is low, therefore, FEI will hold one reserve fund to cover the impact should either of the risks occur. Given there are two risks covered by a single management reserve, FEI has chosen to fund the P70 value of the larger risk or $23.6 million.

On page 92 of the Updated Application, FEI states, "FEI will fund escalation at $11.6 million which corresponds to the P50 level of confidence."

31.3 Please discuss FEI's rationale for selecting the P50 confidence level to estimate escalation. Please discuss why FEI considers the P50 level to be appropriate to estimate escalation for the OCU Project.

Response:

Please refer to the response to BCUC IR1 31.1 where FEI explained the rationale for selecting a P50 level of confidence to derive the contingency amount. FEI used a similar rationale to select the P50 value as the basis for the level of confidence used to fund escalation.

31.4 Please explain whether FEI considered any alternative confidence levels to estimate escalation, other than the P50 confidence level.

31.4.1 If yes, please discuss the alternative(s) considered by FEI, including the advantages and disadvantages of each and please explain why each alternative was rejected.

31.4.2 If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 31.3. FEI engaged a leading industry expert to confirm the reasonableness of FEI's selection of escalation at the P50 confidence level. FEI did not consider funding escalation at any other confidence level.

31.5 Please provide the total OCU Project cost estimate if the P70 confidence level was used to estimate contingency and escalation, as well as the management reserve.

Response:

At a P70 confidence level for contingency, management reserve, and escalation, the total OCU Project cost would increase from $271.3 million to $295.9 million. Note that at the P70 confidence level there is no change to the management reserve which remains at $23.6 million. As a result of the changes in the contingency and escalation, the AFUDC would also increase. The following table outlines the costs at both the P50 and P70 confidence level and the change in costs represented in millions of dollars.

Line	Item	Amount P50	Amount P70	Difference
1	Construction Cost Estimate (Contractor)	153.4	153.4	$--
2	Construction Cost Estimate (FEI)	34.5	34.5	$--
3	*Owner Costs ($25.1M)*			
4	*Inspection Services ($8.6M)*			
5	*AC Mitigation, Cathodic Protection, Deactivation ($0.7M)*			
6	Sub-Total Construction Base Cost Estimate (2020$)	187.9	187.9	$--
7	Project Development Costs (Capitalized Estimate)	6.2	6.2	$--
8	Contingency	25.1	40.4	$15.3
9	Sub-Total Cost Estimate (2020$)	219.2	234.5	$15.3
10	Management Reserve	23.6	23.6	$--
11	Cost Escalation Estimate	11.6	19.5	$7.9
12	Sub-Total Construction Cost Estimate (As-spent)	254.4	277.6	23.2
13	AFUDC	16.8	18.3	1.5
14	Grand Total Project Cost Estimate (As-spent)	271.3	295.9	24.7

E. PROJECT COST ESTIMATE

32.0 Reference: PROJECT COST ESTIMATE

Exhibit B-1-2, Section 6.2, p. 83

Summary of Project Costs

On page 83 of the Updated Application, FEI provides the following table showing a summary of the total cost estimate of the OCU Project:

Table 6-1: Summary of Forecast Capital and Deferred Costs ($millions)

Line	Item	Amount	Reference
1	Construction Cost Estimate (Contractor)	$153.4	Appendix A-3 [30]
2	Construction Cost Estimate (FEI)	$34.5	Appendix B
3	*Owner Costs ($25.1M)*		Appendix B
4	*Inspection Services ($8.6M)*		Appendix B
5	*AC Mitigation, Cathodic Protection, Deactivation ($0.7M)*		Appendix B
6	Sub-Total Construction Base Cost Estimate (2020$)	$187.9	Section 5.10.3
7	Project Development Costs (Capitalized Estimate)	$6.2	Section 6.2
8	Contingency	$25.1	Section 5.10.4.5
9	Sub-Total Cost Estimate (2020$)	$219.2	
10	Management Reserve	$23.6	Section 5.10.4.5
11	Cost Escalation Estimate	$11.6	Section 5.10.4.6
12	Sub-Total Construction Cost Estimate (As-spent)	$254.4	
13	AFUDC	$16.8	
14	Grand Total Project Cost Estimate (As-spent)	$271.3	

32.1 Please discuss the accuracy range of the OCU Project cost estimate.

<u>Response:</u>

The accuracy range of the OCU Project is -5% to +35% at an 80 percent confidence interval of actual costs from the cost estimate. As described in AACE RP 97R-18 *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Pipeline Transportation Infrastructure Industries* one of the secondary characteristics of a Class 3 estimate is the expected accuracy range of low: -10% to -20% and high: +10% to +30%. This range of ranges represents typical percentage variation but as indicated in AACE RP 97R-18, "individual estimates should always have their accuracy ranges determined by a quantitative risk analysis study that results in an estimate probability distribution." FEI conducted such a quantitative risk analysis, included in Confidential Appendix C-2 - Validation Estimating Contingency Report, to establish the OCU Project's accuracy range.

32.2 Please explain how FEI developed FEI's portion of the construction base cost estimate of $34.5 million, including the sources of information used to develop the cost estimate.

Response:

FEI's portion of the construction base cost estimate was developed using an established internal cost estimating process which has been followed in similar CPCN applications. The process began with defining the purpose of the estimate, followed by a plan (in the form of scheduled activities) of how to acquire information to complete, verify, and assemble the estimate for the required class of estimate. Next, using a combination of internal experience and knowledge, and external support for specialized services, FEI undertook the planning process and completed the planning deliverables listed in AACE RP 97R-18, such as:

- Defining the project delivery method;
- Developing a project execution strategy;
- Obtaining permits;
- Identifying stakeholders; and
- Developing the Work Breakdown Structure (WBS) for all Project Services work packages.

Concurrently, the construction schedule is developed by FEI's engineering consultant, and FEI develops a master schedule to show the activities and interfaces required to support the construction timelines. Various leads are assigned to the project to identify the resources required to support project execution. Once the necessary resources are identified, the durations and quantities are identified, and the schedule is optimized through resource leveling where possible. Hourly rates and related expenses are then allocated to the quantity and resource duration, and summed to produce a total cost. FEI's portion of the cost estimate was then reviewed and totaled with the construction cost estimate, contingency, and escalation to form the Project Class 3 estimate.

Please also refer to Confidential Appendix B, FEI Construction Cost Estimate, for a review of the Owner's costs WBS.

Further, on page 83 of the Updated Application Update, FEI states, "Project development costs include all of the costs associated with developing an AACE Class 3 cost estimate in accordance to AACE International Recommended Practices Nos. 18R-97 and 97R-18 as required by the CPCN Guidelines and are estimated to be $6.2 million (2020$)."

32.3 Please provide a detailed breakdown and explanation of the Project Development costs of $6.2 million by line item and year incurred.

<u>Response:</u>

Table 1 below provides details of the Project Development costs of $6.2 million by line item and year incurred.

Table 1: Project Development Cost Breakdown

	Project Development - Capitalized $000's			
Particulars	2018	2019	2020	Total
Engineering Design	$ 8	$ 1,273	$ 2,061	$ 3,342
Engineering Survey	-	84	111	194
Engineering Estimate Validation	-	-	319	319
Engineering Geotechnical	-	14	903	916
Project Services - Project Management	-	(503)	708	205
Project Services - Communications	-	10	118	128
Project Services - Community Relations	-	13	119	132
Project Services - Enviromental/Archaeology	-	9	112	121
Project Services - Indigenous Relations	-	24	78	102
Project Services - Legal	-	-	158	158
Project Services - Operations Support	-	3	-	3
Project Services - Procurement	-	12	81	94
Project Services - Property Services	-	0	421	421
Project Services - Regulatory / Permitting	-	13	83	96
Total	$ 8	$ 951	$ 5,271	$ 6,230

The following tables provides an explanation of the various types of Project Development costs:

Table 2: Engineering – Description of Activities

Activity	Description
Design	Costs associated with developing the Engineering deliverables of the OCU Project to the appropriate level for the CPCN application.
Survey	Costs associated with field survey to support design work for the OCU Project.
Estimate Validation	Costs associated with third party validation of the Class 3 cost estimate for the OCU Project.
Geotechnical	Costs associated with geotechnical work required to support engineering deliverables required to bring the OCU Project to the appropriate level of definition for the CPCN Application.

Table 3: Project Services – Description of Activities

Activity	Description
Project Management	Costs associated with Project Management activities, including cost and schedule oversight, project controls.
Communications	Costs associated with external facing communication of the Project to interested parties.
Community Relations	Costs associated with managing and incorporating feedback from the various communities impacted by the OCU Project.

Activity	Description
Environmental / Archaeology	Costs associated with undertaking, reviewing, and accepting required Environmental and Archaeological assessments to support the OCU Project.
Indigenous Relations	Costs associated with managing and incorporating feedback from the various Indigenous communities impacted by the OCU Project.
Legal	Costs for Project legal support .
Operations Support	Costs for Project operations support.
Procurement	Costs for Project procurement support.
Property Services	Costs associated with acquiring the necessary land rights to support the Project.
Regulatory / Permitting	Costs associated with developing the required regulatory and permitting plans for the OCU Project.

33.0 Reference: PROJECT COST ESTIMATE

Exhibit B-1-2, Section 6.3.2, p. 96, footnote 35, p. 96

Application and Preliminary Stage Development Costs

On page 96 of the Updated Application, FEI states:

> FEI is seeking BCUC approval under Sections 59-61 of the UCA for deferral treatment of the Application and Preliminary Stage Development costs. The Application costs are based on a written hearing process and include expenses for legal review, consultant costs, BCUC costs and BCUC-approved intervener costs. The Preliminary Stage Development costs are related to expenses incurred for engaging third-party consultants for feasibility evaluation, preliminary development and assessment of the potential design and alternatives as required to complete this Application. … FEI proposes to transfer the balance in the deferral account to rate base on January 1, 2022 and commence amortization over a three-year period.
>
> Table 6-3 below shows the December 31, 2020 net-of-tax balance for the Application costs and the Preliminary Stage Development costs is forecast to be a credit of $795 thousand.

Table 6-3: Forecast Application Costs and Preliminary Stage Development Costs ($000s)

Particulars	Application Costs	Preliminary Stage Development Costs	Total
Pre-tax Costs	$400	$902	$1,302
Income Tax Recovery:			
Costs held in deferral account[34]	$(108)	$(244)	$(352)
Capitalized Costs[35]		$(1,682)	$(1,682)
Total Tax Offset	$(108)	$(1,926)	$(2,034)
Financing, WACC after tax	$10	$(73)	$(63)
Total	$302	$(1,097)	$(795)

In footnote 35 to Table 6-3 on page 96 of the Updated Application, FEI states, "Income tax recovery on the development costs that were capitalized but are deductible for tax purposes. The amount shown is equal to the costs capitalized of $6.2 million times the income tax rate of 27%."

33.1 Please provide a breakdown of the Application costs of $400,000 and the Preliminary Stage Development costs of $902,000 by each activity (e.g. consultant costs, legal costs etc.) for each year incurred.

Response:

The excerpt from the Updated Application quoted in the preamble includes an error in the referenced date. The net-of-tax balance of $(795) thousand is at December 31, **2021,** not 2020.

The following table provides a breakdown of the forecast Application costs of $400 thousand, by year and type of cost. Only actual costs will be recorded in the deferral account.

Particulars	CPCN Application Costs $000's 2020	2021	2022	Total
BCUC	$ -	$ 60	$ -	$ 60
Intervenor PACA Award	-	70	-	70
Legal	40	190	-	230
Expert / Consultant	-	5	-	5
Notice / Publication	-	32	-	32
Administrative	-	3	-	3
Total	$ 40	$ 360	$ -	$ 400

In preparing this response, FEI has shifted $20 thousand of Application costs from 2020 to 2021 as this better aligns costs to the end of 2020 and projected costs for 2021. These costs are associated with external legal counsel support. (For original timing of total gross Application costs see Confidential Appendix E-2, Schedule 9, Line 12).

The following table provides a breakdown of the Preliminary Stage Development costs, $902 thousand, by year and activity. An explanation of the activities follows after the cost table.

Particulars	Preliminary Stage Development $000's 2018	2019	2020	Total
Engineering Design	$ 114	$ -	$ -	$ 114
Project Management	-	788	-	788
Total	$ 114	$ 788	$ -	$ 902

FEI is forecasting $902 thousand for Preliminary Stage Development Costs. These are actual costs incurred by FEI up to November 30, 2019 associated with the project management, engineering and consultants for assessing the potential design and alternatives for the Project. Engineering and Project Management after November 30, 2019 were related to the AACE Class 3 cost estimation and project development of the preferred alternative and are part of the $6.2 million that is discussed in BCUC IR1 32.3.

Engineering Design includes costs associated with developing the engineering deliverables of the OCU Project to the appropriate level for the CPCN Application. Project Management includes costs associated with project management activities, including cost and schedule oversight, and project controls.

33.2 Please clarify whether the income tax recovery of the capitalized costs relates to the Capital Cost Allowance (CCA) deduction of the capitalized Project Development Costs.

Response:

The Income Tax Recovery does not relate to the Capital Cost Allowance deduction of the capitalized Project Development Costs. The capitalized Project Development Costs of $6.2 million are not added to the Undepreciated Capital Cost (UCC) pools but are instead tax deductible in the year incurred. Therefore, the income tax recovery is derived by expensing, for Income Tax payable purposes, the capitalized portion of the Development Costs, $6.2 million, multiplied by the tax rate of 27 percent ($6,230.4 thousand x 27% = $1,682 Income Tax Recovery).

By including the tax recovery in the proposed deferral account, to be amortized over three years, the value of the tax recovery benefit is returned to ratepayers much sooner than if FEI were to include the $6.2 million in its UCC pools, which would then cause the income tax recovery benefit be returned to ratepayers over 65+ years.

It is FEI's standard regulatory practice to record the tax benefit in a net-of-tax deferral account. This enables matching of the tax benefit to customers to the recovery of associated costs. This practice was confirmed in BCUC Order G-53-94, Page 2.

> Deferred Account Balances in Rate Base
>
> If deferred expenses or credits are included in the utility's actual tax calculation in the year they are first recorded, then the amounts shall be recorded in rate base on a net of tax basis. If such expenses or credits are not included in the utility's tax calculation then the amounts shall be on a before tax basis.

33.3 Please explain why FEI proposes to include the income tax recovery of the capitalized costs of $6.2 million in the deferral account.

Response:

Please refer to the response to BCUC IR1 33.2.

33.4 Please provide FEI's rationale for proposing to amortize the deferral account over a three-year period.

Response:

The proposed three-year amortization period for the OCU Application and Preliminary Stage Development Costs deferral account is consistent with similar deferral account treatment approved for recent FEI CPCN applications:

- BCUC Order G-12-20 for the Inland Gas Upgrades Project approved a single Application and Preliminary Stage Development Costs deferral account with a three-year amortization period;
- BCUC Order C-11-15 for the Lower Mainland Intermediate Pressure System Upgrade Project approved two separate deferral accounts for the Application and Project Development costs, both with three-year amortization periods; and
- BCUC Order C-2-14 for the Muskwa River Crossing Project for the Fort Nelson Service Area approved a single Application and Project Development Cost deferral account with a three-year amortization period.

Given the size of the projected balance in the deferral account, FEI believes either a one or two year amortization period could also be appropriate. FEI ultimately selected an amortization period of three years which is consistent with recent BCUC approvals.

33.5 Please explain whether FEI considered any alternative amortization periods, other than three years.

33.5.1 If yes, please discuss the alternative amortization period(s) considered by FEI, including the advantages and disadvantages of each and please explain why each alternative was rejected.

33.5.2 If not, please explain why not.

Response:

FEI did not consider other amortization periods for the proposed deferral account for the OCU Project. In the table below, FEI shows the change in the total Project rate impact if the amortization period is changed to one year, two years, four years or five years. The change in amortization period has no impact on the long term average percentage change on delivery rates and the levelized rate impact.

Over the five years from 2022 to 2026, varying the amortization period results in customers being marginally better off in some years, some years would have no impact, and in other years customers would be marginally worse off, depending on the amortization period.

As discussed in response to the BCUC IR1 33.4, FEI is proposing to amortize the application and development costs over a three-year period, which is consistent with past BCUC CPCN decisions.

Rate Change Impact From Varying Amortization Period That Begins in 2022

Rate Impact $ / GJ	2022	2023	2024	2025	2026
3 Year Amortization [1)]	$ (0.002)	$ (0.001)	$ 0.100	$ 0.107	$ 0.108
1 Year Amortization	$ (0.006)	$ 0.001	$ 0.102	$ 0.106	$ 0.107
Change from 3 Year Amortization	$ (0.004)	$ 0.002	$ 0.002	$ (0.001)	$ (0.001)
2 Year Amortization	$ (0.003)	$ (0.002)	$ 0.102	$ 0.107	$ 0.108
Change from 3 Year Amortization	$ (0.001)	$ (0.001)	$ 0.002	$ -	$ -
4 Year Amortization	$ (0.002)	$ (0.001)	$ 0.100	$ 0.105	$ 0.108
Change from 3 Year Amortization	$ -	$ -	$ -	$ (0.002)	$ -
5 Year Amortization	$ (0.001)	$ (0.001)	$ 0.100	$ 0.105	$ 0.107
Change from 3 Year Amortization	$ 0.001	$ -	$ -	$ (0.002)	$ (0.001)

1) Reference: Confidential Appendix E-2, Schedule 10, Line 39

Note: The rate impacts shown above are for the overall OCU Project, not just for the deferred application and development costs. Also, the change would affect all non-bypass ratepayers.

34.0 Reference: PROJECT COST ESTIMATE

Exhibit B-1-2, Section 6.4, pp. 96–97

Rate Impact

On page 97 of the Updated Application, FEI provides the following table showing the annual delivery rate impact compared to the 2021 applied for non-bypass revenue requirement and the incremental annual delivery rate impact in percentage in 2024:

Table 6-4: Summary of Rate Impact for the Project

Particulars	Impact
Incremental Revenue Requirement ($000s)	$19,448
% Increase to 2021 Applied for Revenue Requirement, Non-Bypass (August, 2020)[37]	2.21%
Delivery Rate Impact (2024) $ / GJ	$0.100
Levelized Rate Impact $ / GJ (**2019 – 2088**)	$0.073

Further, on page 97 of the Updated Application, FEI states that "the Project will result in an estimated delivery rate impact of 2.21 percent in 2024 when all construction is complete and after all assets are placed in service in 2023."

34.1 Please discuss the assumptions used to calculate the rate impact, including the assumptions associated with the load forecast including growth in customer accounts and rationale for each assumption.

Response:

FEI did not consider growth in customer accounts, growth in volumes, or growth in delivery margin revenue when calculating the Project rate impacts. This approach is consistent with previous FEI CPCN applications. The purpose of the rate impact calculations in the Updated Application is to show the impact to existing rates, or in this case, relative to what was approved in the FEI Annual Review for 2021 Rates; i.e. holding the delivery margin revenue and volumes constant over the years. This results in a high-level estimate of the rate impact relative to the most recently approved rates. The actual rate impacts of the Project will not be known until a future Annual Review or Revenue Requirements proceeding when the costs of the Project are added to rate base at that time. Any increased growth in the delivery margin or volumes would only reduce the rate impact shown in Table 6-4.

34.2 Please clarify whether FEI considered any potential increase in volumes sold, as a result of the OCU Project, when determining the rate impact provided in Table 6-4.

34.2.1 If yes, to what extent to does the increased revenue offset the rate impact of the project?

34.2.2 If no increase in volumes is reflected in the rate impact, please explain why not.

Response:

Please refer to the response to BCUC IR1 34.1.

F. ENVIRONMENT AND ARCHEOLOGY

35.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-2, Section 7.1, p. 98

First Nations engagement and consultation

FEI states on page 98 of the Updated Application that draft versions of both the Environmental Overview Assessment (EOA) and Archaeological Overview Assessment (AOA) were provided to Indigenous communities who requested drafts for their review and comment. At the time of writing, FEI had not received any comments; however, any comments that are received will be incorporated during the detailed engineering phase of the Project.

35.1 Please provide an update on engagement with Indigenous communities with regards to the EOA and the AOA, including anticipated timelines for future engagement.

Response:

Engagement with potentially impacted Indigenous groups has occurred throughout the Project to date, and will continue throughout the remaining Project phases, on a community by community basis. With regard to the updates on the AOA and EOA, FEI sent the reports to Indigenous groups with a stated interest.

The Penticton Indian Band reviewed the EOA report and provided comments while Westbank First Nation deferred comment on the EOA to the Penticton Indian Band. Comments provided by the Penticton Indian Band did not materially change the EOA and therefore will be addressed during the environmental field program and in the Project Environmental Management Plan.

A confidential AOA was facilitated by the Penticton Indian Band, and conducted by the Syilx Traditional Ecological Knowledge Keepers (TEKK) – a group of individuals from communities across the Syilx traditional territory. The recommendations of this AOA will be addressed during the Archaeological Impact Assessment.

36.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-2, Appendix F, Table 6.1, p. 42

Overview of Potential Effects and Risks

Table 6.1 of Appendix F identifies several follow-up activities to mitigate project risks related to Land Use and the use of public roadways including engagement with the Ministry of Transportation and Infrastructure.

36.1 Please describe the engagement that has occurred with the Ministry of Transportation and Infrastructure to date.

Response:

In June 2020, FEI began communications with various contacts at the Ministry of Transportation and Infrastructure (MoTI) to understand who within MoTI should be consulted, and to provide a general awareness of the Project. In September 2020, FEI conducted two formal meetings with MoTI staff members.

The first meeting provided an overview of the route and allowed both FEI and the MoTi teams to gain an understanding of potential Project interactions with MoTI infrastructure. MoTI also reviewed the permitting process, the requirements in the MoTI Utility Policy Manual, and the application process for a variance if the gas line design is not in accordance with the MoTI Utility Policy Manual.

The gas line design for the OCU Project does not meet some of the criteria specified within the MoTI Utility Policy Manual as follows:

1. approximately 550 metres of the proposed alignment falls inside, or within 30 metres of and parallel to the MoTI Saliken Drive right of way (ROW), near the City of Penticton;
2. the crossing of Saliken Drive is proposed to be completed using an uncased open trench method;
3. the crossing of Chute Lake Road is currently designed to cross the MoTI ROW at an angle less than 70 degrees; and
4. the crossing of Chute Lake Road is proposed to be completed using an uncased open trench method.

The second meeting was held to discuss the specific details of and the need for variances. FEI submitted the variance application in January 2021 and expects a response from the MoTI in March 2021.

Table 6.1 identifies several Moderate to High project risks related to Surface Water Quality and Quantity, noting "construction timing (i.e., avoid periods of heavy precipitation" as a possible follow up activity.

36.2 Please discuss any adjustments to the construction schedule to mitigate these project risks.

Response:

The construction contract will include an environmental management plan which specifies all of the environmental requirements for the Project and the contractor will be required to prepare an environmental protection plan (EPP). FEI has planned construction work to proceed throughout the year. The contractor will be responsible for scheduling their work locations and activities to meet the contract requirements and in accordance with their EPP.

In the construction contract there will be an "adverse weather" clause so that FEI and the contractor may effectively address poor weather conditions such as heavy rain and snow. In addition, the contract will include unit price items for environmental protection measures such as silt fences, erosion control matting, etc. An allowance for adverse weather and extra work (if required) has been included in the Project contingency funding.

Table 6.1 notes high project risks associated with Fish and Fish Habitat, and follow-up activities include:

- Conduct instream works within reduced risk work window.
- To the extent practicable, undertake construction within the least-risk timing windows for applicable species.

36.3 Please discuss how FEI has adjusted its plan for instream works to align with the reduced risk work window.

Response:

The current schedule in the Updated Application has not been adjusted for instream works. During the detailed design phase of the Project, FEI will finalize the environmental requirements and the construction methodology for each water crossing in collaboration with the Penticton Indian Band and Westbank First Nation. Once complete, the requirements will be documented in an Environmental Management Plan (EMP) and provided to the construction contractor for compliance.

FEI expects that the contractor will undertake all instream works on fish bearing and fish habitat-streams during the reduced risk window of August 7 to October 15, other species-specific (i.e., amphibians) reduced risk windows as appropriate, or when the watercourses are dry.

37.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-2, Section 7.2.1.2, p. 100; Appendix F, Table 6.2, p. 44

Contaminated Sites and Environmental Permitting

FEI states on page 100 of the Updated Application:

> Locations where there is a medium to high potential for encountering soil or groundwater contamination within the Project footprint may impact construction cost, and timelines. These areas are defined as APECs [area of potential environmental concern]. One high risk and one low risk APEC were identified in the contaminated sites study area. … The high risk APEC is associated with an active landfill that includes operations dating back to 1972.

Hemmera recommends on page 44 of Appendix F that planning and construction be coordinated with the Campbell Mountain Landfill to comply with conditions of their landfill operating permit.

37.1 Please discuss what steps FEI has taken to engage with the operators of the Campbell Mountain Landfill to date.

Response:

The Campbell Mountain Landfill is operated by the Regional District of Okanagan-Similkameen (RDOS) and located on land leased from the City of Penticton.

FEI met with the RDOS Electoral Area 'E' (Naramata) Director and City of Penticton staff (including the Mayor) in Q1 2020 to provide a high level overview of the Project and the gas line route. Since May 2020, FEI and the Campbell Mountain Landfill operators have met numerous times to discuss the Project and to address any concerns or questions the operators had with respect to the pipeline alignment crossing through the landfill property. From those interactions, FEI adjusted the route to address their concerns. FEI is currently working with the Campbell Mountain Landfill operator's preferred environmental consultant, Sperling Hansen, to better understand the environmental implications of constructing a gas line through a short section of the landfill. FEI will continue to consult with the operators of the Campbell Mountain Landfill until all outstanding issues are resolved.

37.2 Please discuss the potential impact of this high risk APEC (VP1) on construction cost and timelines.

Response:

The cost and schedule implications associated with contaminated soil at the landfill were unknown at the time of developing the AACE Class 3 cost estimate for the Project, and therefore it is treated as a project-specific risk. The AACE Class 3 cost estimate includes a budget to further investigate APEC VP1 at the Campbell Mountain Landfill and once the investigation is complete, FEI's environmental consultant will provide advice on how to handle the contaminated soil, if any is identified. As the APEC VP1 study will take place well in advance of construction, FEI does not expect a schedule delay, however there may be additional costs required to handle the contaminated soil and if so they will be drawn from the Project contingency.

38.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1, Section 7.2.3, p. 103; Appendix F, Table 6.3, p. 45

Permitting

FEI states on page 103 of the Updated Application that all required environmental permits and approvals for the Project will be identified and applied for during the detailed engineering phase of the Project.

A list of anticipated permits and approvals along with the estimated timeframe for issuance is provided in Table 6.3 of Appendix F.

38.1 Please confirm if FEI has submitted a request for project review to Fisheries and Oceans Canada yet, including the date of submission if applicable. If not, please indicate when FEI intends to submit the request.

Response:

FEI has not submitted a request for review of the Project to Fisheries and Oceans Canada at this time. FEI expects that the first request for Project review will be submitted late Q1 2021 with an additional request for Project review to be submitted in mid Q3 2021.

38.2 Please confirm if FEI has submitted an application for the Waste Discharge Authorisation to the BC Oil and Gas Commission, including the date of submission if applicable. If not, please indicate when FEI intends to submit the application.

Response:

At this time, FEI does not expect to need a BCOGC Waste Discharge Authorization. If during detailed engineering it is determined that a Waste Discharge Authorization is required, FEI would apply for it in approximately Q3 2021.

38.3 Please confirm if FEI has received formal confirmation of the exemption from the Regional District of Okanagan-Similkameen for:

- the Environmentally Sensitive Area Development Permit; and
- the Watercourse Development permit.

Response:

Formal confirmation of the exemptions is not required as natural gas public utility work is exempted from the requirement for Environmentally Sensitive Area Development Permits and Watercourse Development Permits in Sections 23.2.8 and 23.3.8, respectively, of the Electoral Area "E" Official Community Plan Bylaw No. 2458, 2008.[10]

[10] https://www.rdos.bc.ca/assets/bylaws/planning/AreaE/2458-A.pdf.

G. CONSULTATION AND ENGAGEMENT

39.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-1-2, Section 8.2.5.3 pp. 113, 114

Consultation with Landowners

FEI notes on page 113 of the Updated Application that as a result of consultation with landowners, FEI was able to make adjustments to the route which ultimately decreased the number of directly impacted landowners from 57 to 38. Of the 57 original landowners to whom FEI sent the initial notification letter, five of those landowners responded. FEI subsequently followed up with landowners that did not respond to the initial notification letter.

FEI states on page 114 of the Updated Application that it began negotiations to acquire the necessary land rights in August and September 2020. The landowners were given a document package that included an independent real estate market appraisal of their property based on the latest IOP, the standard form of Agreement to Grant Statutory Right of Way and Temporary Work Space.….FEI is committed to negotiating fair agreements with landowners along the route and will continue to engage with landowners post CPCN filing to acquire the requisite land rights. Should FEI be unable to reach agreement with landowners, FEI will follow the internal escalation procedure outlined in the Land Acquisition Plan, including pursuing its rights to expropriate land in accordance with applicable legislation. <u>As at the filing date FEI has come to agreement with 13 of 38 private landowners.</u> [*Emphasis added*]

39.1 Of the 38 directly impacted landowners, please confirm if all of them have now responded to FEIs notification. If not confirmed, please clarify how many have not responded, and outline the steps FEI is taking to ensure notifications have been received.

<u>Response:</u>

FEI confirms that all 38 directly impacted landowners have responded to its notification.

39.2 Please provide an update with regard to the signing of agreements with the 38 private landowners.

<u>Response:</u>

Since filing the Updated Application, FEI has refined the route to address landowner feedback, constructability challenges, and contingency plans, resulting in an additional two impacted landowners. The following table provides a summary of land acquisition progress to date.

	Required	Obtained
Private rights-of-way	35	22
Private temporary workspace	2	1
Municipal City of Penticton rights-of-way	3	0
Total	40	23

FEI continues to work with the remaining unsigned property owners to address their concerns. While FEI's objective is to secure required land rights for the Project through open and transparent negotiations with landowners, FEI anticipates that there may be instances where a negotiated settlement with a landowner cannot be reached. In these cases, FEI would expect to expropriate in order to secure the required land rights, along with providing fair market value compensation.

39.2.1 If applicable, please discuss the possible impact of an expropriation process on the project schedule.

Response:

FEI's objective is to reach mutually acceptable negotiated agreements with landowners. Should an agreement not be reached and result in the potential for Project construction delays, FEI will take steps to expropriate the required land rights. Should FEI need to proceed with expropriation in a particular situation, FEI would make an application under Section 6 of the *Gas Utility Act* or section 34(3) of the *Oil and Gas Activities Act* as appropriate for approval to expropriate the necessary land. Should FEI have to undertake expropriation, costs are not expected to vary beyond those in the estimate.

39.3 Please discuss what steps FEI takes to ensure the independence of the real estate company.

Response:

FEI has already engaged an independent, third-party real estate appraisal firm and provided it with a scope of work to prepare necessary valuation reports to assist in land acquisition negotiations with private landowners. The appraiser has had the opportunity to meet with landowners to understand and evaluate their concerns during site inspections. FEI was provided with drafts of appraisal reports prior to finalization and had the opportunity to ask questions of the appraisers as necessary.

All appraisal reports are completed in compliance with the Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) and each appraiser is bound by the Appraisal Institute of Canada Code of Ethics.

39.4 Please clarify where the budget for all payments associated with property acquisition (including both statutory rights of way and temporary work space) appears in the project cost estimate. Responses can be provided confidentially if necessary.

Response:

Please refer to the response to BCUC Confidential IR1 4.2.

H. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES

40.0 Reference: PROVINCIAL GOVERNMENT ENERGY OBJECTIVES

Exhibit B-1-2, Section 9.2, p. 125

Policy Considerations

FEI states on page 125 of the Updated Application that the OCU Project will support the British Columbia energy objective found in section 2(k) of the CEA "to encourage economic development and the creation and retention of jobs."

Section 2 of BC's Clean Energy Act outlines BC's energy objectives, including:

…

(b)to take demand-side measures and to conserve energy,…

…

(g)to reduce BC greenhouse gas emissions

…

(iii)by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv)by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v)by such other amounts as determined under the Climate Change Accountability Act;

(h)to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i)to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j)to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k)to encourage economic development and the creation and retention of jobs;…"

40.1 Please discuss the extent to which project is consistent with and will advance the BC government's energy objectives as set out above.

Response:

As described in the Updated Application, the Project primarily supports objective (k) to encourage economic development and the creation and retention of jobs. The Project provides vital capacity to serve the growing energy needs of homes, business and industry in the central and north Okanagan regions which, in the absence of the Project, are expected to experience a capacity shortfall in the winter peak of 2023/2024. As described in Section 1.2.1 of the Updated Application, Kelowna has been one of the fastest growing cities in Canada in the past decade and is forecast to grow at a similar rate in the coming two decades. The continued supply of safe, reliable and affordable energy to new and existing customers in the region will support economic activity and the creation and retention of jobs.

In addition, the construction of the Project is expected to have positive employment impacts by contributing to the local economy in the central and north Okanagan regions. In particular, the procurement of local materials, and the use of local services such as lodging and dining, will contribute local economic activity.

More generally, the Project is aligned with the provincial energy objective to reduce greenhouse gas emissions. The gas energy delivery system, including the Project, delivers low carbon energy (i.e. renewable gas) to customers in the province. FEI continues to increase its supply of renewable gas in alignment with the provincial CleanBC target to achieve 15 percent renewable gas content by 2030. Over the longer term to 2050, FEI envisions a future where the majority of the energy it delivers, including through the Project, is renewable.

Attachment 25.1

ATTACHMENT 25.1: CLASS 3 ESTIMATE WATERCOURSE CROSSINGS LIST

Excerpted from Table 4.5 - Watercourses Overlapping the General Study Area, Classifications, and Riparian Setbacks (P-00760-ENV-EOA-0001 - ENVIRONMENTAL ASSESSMENT REPORT)

Project KP	Tie-in KP	Segment	Northing	Easting	Crossing name	Input Category	Construction Methodology	Environmental Protection and Management Regulation Classification	Riparian Management Area	Local Watershed Code[1]	Stream Order	Fish Bearing	Location or Crossing Description	Streamside Protection and Enhancement Area[2]
1+007.08	31+794.28	1	5483860.278	316166.377	Ellis Creek Tributary	Stream	Open Cut	NCD	n/a	300-432687-623544-1139914 (Tributary to Ellis Creek)	1	No	An unnamed watercourse overlaps the study area and runs parallel to before crossing the pipeline under Saliken Drive.	15-30
1+638.69	32+425.89	1	5484479.368	316258.796	Unnamed Watercourse	Stream	Open Cut	NCD	n/a	300-432687-623544-102657-539790	1	No	An unnamed watercourse overlaps with the study area and the pipeline.	15-30
2+854.30	33+641.50	2	5485687.124	316316.206	Penticton Creek	Stream	HDD	S2	50	300-432687-637835-179687 (Penticton Creek)	3	Yes	Penticton Creek overlaps with the study area and the pipeline and flows into Okanagan Lake.	30
3+555.27	34+342.47	3	5486368.897	316294.019	Penticton Creek Tributary	Stream	Open Cut	NCD	-	300-432687-637835-211241 (Penticton Creek tributary)	1	No	An unnamed watercourse crosses with the study area and pipeline and joins Penticton Creek to the east of the study area before Penticton Creek crosses the alignment.	15-30
5+584.00	36+371.20	4	5488005.892	315493.008	Randolph Creek Tributary	Stream	Open Cut	NSCI	n/a	300-432687-644621-853582 (Randolph Creek tributary)	1	No	An unnamed watercourse crosses with the study area and pipeline northwest of Reservoir Road and joins Randolph Creek within the study area	**
5+656.95	36+444.15	4	5488068.663	315455.838	Randolph Creek	Stream	Open Cut	NSCI	n/a	300-432687-644621-853582 (Randolph Creek)	1	**Yes (downstream of study area)	Randolph Creek crosses with the study area and pipeline and flows into Okanagan Lake.	**
5+880.13	36+667.33	4	5488272.839	315384.396	Randolph Creek Tributary	Stream	Open Cut	NSCI	-	300-432687-644621-764561 (Randolph Creek tributary)	1	No	An unnamed watercourse crosses with the study area and pipeline and joins with Randolph Creek to the west of the study area.	**
7+824.90	38+612.10	4	5490100.627	315189.957	Strutt Creek	Stream	Open Cut	S6	30	300-432687-646321 (Strutt Creek)	3	No	Strutt Creek crosses the study area and the pipeline and flows into Okanagan Lake.	15-30
8+801.88	39+589.08	5	5490998.263	314967.889	Johnson Spring Creek	Stream	Open Cut	NSCI	n/a	300-432687-647543 (Johnson Spring Creek)	1	Yes (downstream of study area)	Johnson Spring Creek crosses the study area and the pipeline and flows into Okanagan Lake.	**
10+564.50	41+351.70	5	5492635.968	314680.390	Turnbull Creek	Stream	Open Cut	S3	30	300-432687-655718-140892 (Turnbull Creek)	1	Yes	Turnbull Creek crosses the study area and the pipeline and flows into Okanagan Lake.	30
14+234.14	45+021.34	6	5495895.996	315010.320	Arawana Creek Tributary	Stream	Open Cut	NSCI	n/a	300-432687-664623-601339 (Tributary to Arawana Creek)	1	No	An unnamed watercourse crosses the study area and the pipeline, and joins Arawana Creek outside the study area	**
14+357.26	45+144.46	6	5496007.401	315060.974	Arawana Creek	Stream	Open Cut	S3	40	300-432687-664623-262113 (Arawana Creek)	2	UKN	Arawana Creek crosses the study area and the pipeline and flows into Okanagan Lake.	30
15+313.28	46+100.48	6	5496811.776	314883.023	Naramata Creek	Stream	Open Cut	S2	40	300-432687-668498-081260 (Naramata Creek)	3	Yes	Naramata Creek overlaps with the study area and the pipeline and flows into Okanagan Lake.	30
18+192.56	48+979.76	7	5499518.500	314177.142	Robinson Creek	Stream	Open Cut	S3	40	300-432687-674998 (Robinson Creek)	2	Yes	Robinson Creek crosses the study area and the pipeline and flows into Okanagan Lake.	30
19+782.54	50+569.74	7	5501018.937	313684.375	Trust Creek	Stream	Open Cut	S3	40	300-432687-675833-666895 (Trust Creek)	1	Yes	Trust Creek crosses the study area and the pipeline and flows into Okanagan Lake.	30
20+009.12	50+796.32	7	5501235.621	313618.235	Watercourse	Stream	Open Cut	These crossings were identified during field reconassaince by Golder Geotechnical and are not included in P-00760-ENV-EOA-0001.						
24+008.38	54+795.58	7	5505085.167	313954.0624	Watercourse	Stream	Open Cut							
24+023.53	54+810.73	7	5505097.442	313962.9349	Watercourse	Stream	Open Cut							
25+150.75	55+937.95	7	5505980.509	314656.2958	Watercourse	Stream	Open Cut							
25+310.75	56+097.95	7	5506086.576	314774.4243	Watercourse	Stream	Open Cut							
26+365.93	57+153.13	7	5506810.739	315531.6577	Chute Creek	Stream	Open Cut	S2	50	300-432687-688607-416446 (Chute Creek)	3	Yes	Chute Creek overlaps with the study area and the pipeline and flows into Okanagan Lake.	30
27+782.00	58+569.20	8	5507603.742	316600.1479	Chute Creek Tributary	Stream	Open Cut	NCD	n/a	300-432687-688607-484441 (Chute Creek tributary)	1	No	An unnamed watercourse overlaps the study area and the pipeline and joins Chute Creek south of the study area before Chute Creek crosses the study area.	**

Notes:

NSCI = no stream channel identified; NCD= Non-classified Drainage; N/A = not applicable; FWA = Freshwater Atlas; UKN = unknown

= not assessed during PFR

[1] 1:20,000 FWA watershed codes have a 300 prefix.

[2] Calculated from a Simple Assessment at the crossing location.

**If there is no watercourse present, then SPEA setbacks do not apply.