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March 4, 2021

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599152

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-1-2, pages 2 and 3 and Appendix D

Request for Confidential Treatment of Certain Appendices

To support the Application, FEI has filed several Appendices, with the following ones being filed confidentially in accordance with the BCUC's Rules of Practice and Procedure, as set out in Order G-15-19.

- Appendix A – Solaris FEED Report Documents
- Appendix B – Construction Cost Estimate (FEI)
- Appendix C - Risk Analysis Reports
- Appendix E – Financial Schedules
- Appendix H-14 – OCU Land Acquisition Plan
- Appendix H-18 - Status of Private Landowner Property Acquisition
- Appendix I-5 – OIB Consultation Response

FEI respectfully requests that the BCUC hold the above listed documents confidential, and believes that such information should remain confidential even after the regulatory process for this Application is completed. Below, FEI will outline the reasons for keeping the information confidential.

Appendix D

Appendix D includes cost estimates, containing capital cost estimates for the Project. They should be kept confidential on the basis that FEI may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding.

Appendix D
DETAILED SCHEDULE

1.1 Appendix D, Detailed Schedule is included in the Public documents and does not contain capital cost estimates. Please confirm that FEI does not intend to keep Appendix D confidential.

Response:

Confirmed. The reference in the preamble to Appendix D was a typographical error and should have instead referenced Appendix E – Financial Schedules. FEI does not intend to keep Appendix D confidential.

1.2 Please confirm that FEI intended to reference Appendix E, E-1, and E-2 as including costs estimates and requiring confidential treatment.

Response:

Please refer to the response to CEC IR1 1.1.

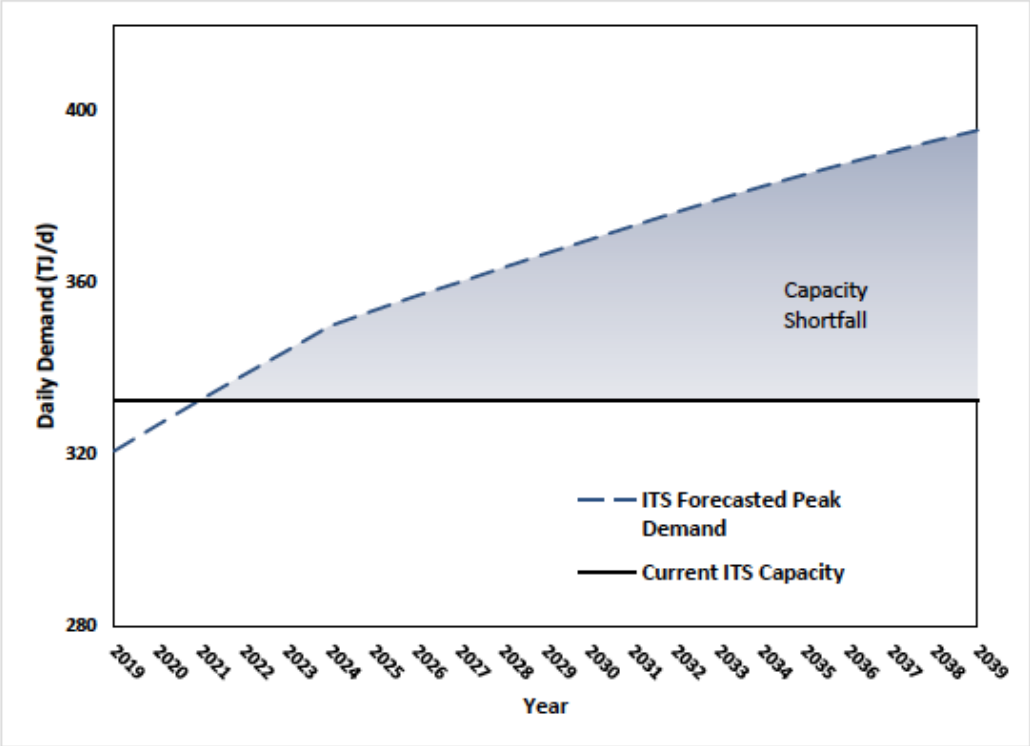
2. Reference: Exhibit B-1-2, pages 18 - 20 and page 29

Figure 3-7 below illustrates the current capacity limit of the ITS under peak cold winter conditions versus the forecast increase in demand across the whole ITS (as shown previously in Figure 3-6), with the capacity shortfall shown as the shaded region under the demand curve. Note that the forecast demand curve meets the current ITS capacity line in 2021, suggesting that the ITS will reach its capacity limit in the winter of 2021/2022. However, FEI's system capacity planning group has identified short-term mitigation measures that can be used through the winter of 2021/2022 and 2022/23, if required, to manage the peak load within the available

[10] System design temperature is determined for each region by calculating the coldest day which is statistically likely to occur once in a 20-year period. FEI's system is designed to meet the peak demand which would occur during this extreme cold weather event. The statistical 20-year low is calculated using information from local weather stations, and is updated as weather trends change.

system capacity while FEI implements a practical long-term solution. These short-term mitigation measures are described further in Section 4.2 of the Application.

Figure 3-7: ITS Peak Demand vs. Capacity



The need to address a future capacity shortfall in the Okanagan area was previously identified in FEI's December 14, 2017 Long Term Gas Resource Plan (LTGRP) filing:[15]

2.1 Please state when FEI first became aware of the expected capacity shortfall.

Response:

Please refer to the response to BCUC IR1 18.1, which includes a discussion of the expected capacity shortfall since 2004.

2.2 Why did FEI wait until November 2020 to make an application for the proposed upgrade when the capacity shortfall is expected to occur in 2021?

Response:

When planning for projects that require major system upgrades, the timing for filing an application is determined by striking a balance between employing short-term mitigation measures and finding an appropriate long-term and practical solution. Time is required to identify, analyze, and evaluate all alternatives and select the preferred solution. As discussed in the responses to CEC IR1 10.2 and 17.1, FEI typically defers initiation of major system upgrades as long as is practical to maximize utilization of existing system capacity, ensuring that ratepayers receive maximum value from those assets. In this situation, the available short-term mitigation measures allowed FEI to defer the capacity shortfall into 2023 and allowed the identification of the most cost-effective solution to address the capacity shortfall. Based on these considerations and this timeline, FEI believes that November 2020 was the appropriate time to file the Updated Application.

2.2.1 Would FEI have been able to undertake different options if it had addressed the issue earlier? Please explain.

2.2.1.1 If yes, what other options could FEI have introduced, and at approximately what cost?

Response:

Addressing the issue earlier would not have resulted in a different option being proposed. As discussed in Section 3.4 of the Updated Application, the need to address a future capacity shortfall in the Okanagan area was previously identified in FEI's 2017 LTGRP filing. Since then, FEI has considered and examined options to address the need and timing for the OCU Project. All feasible options were further evaluated to determine their performance in relation to the evaluation criteria defined for the Project, and Alternative 3 (the OLI PEN 406 pipeline extension) was selected as the preferred solution for the Project.

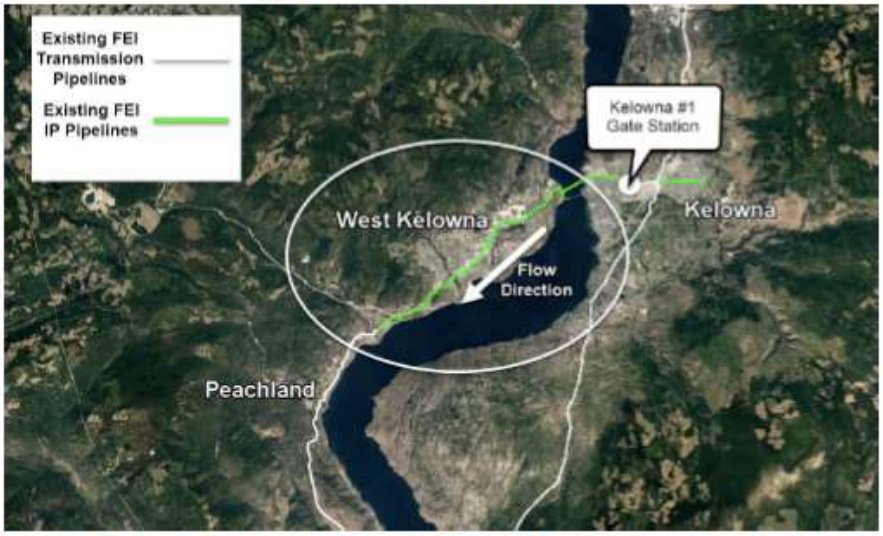
2.3 To what extent could FEI utilize capacity-related DSM measures to defer the increase? Please identify the types of measures and the potential impacts that might have been employed.

Response:

Please refer to the responses to BCSEA IR1 7.2 and 8.1 for a discussion of capacity-related DSM.

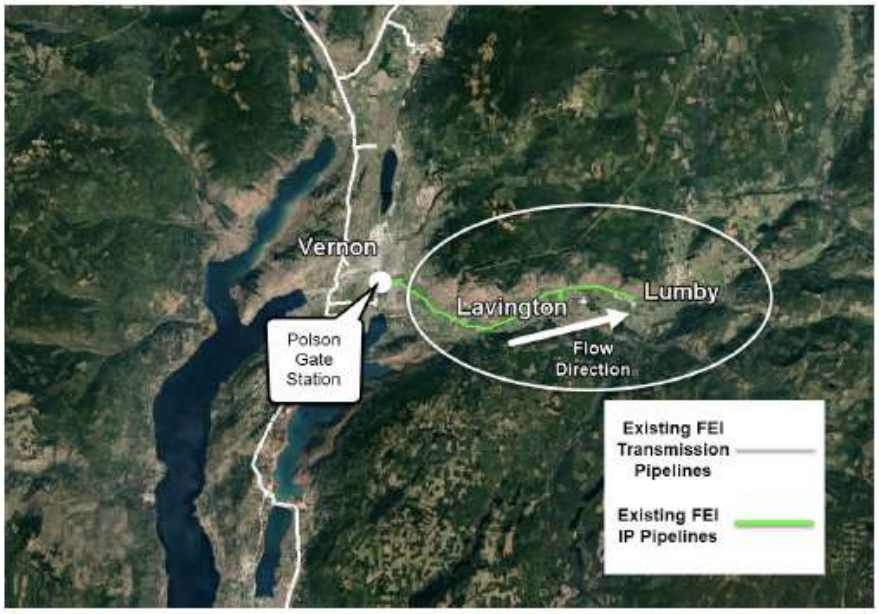
3. Reference: Exhibit B-1-2, page 27

Figure 3-9: West Kelowna and Peachland



Source: Google Earth overlaid with FEI transmission pipeline location data (10/5/2020)

Figure 3-10: Lavington and Lumby



Source: Google Earth overlaid with FEI transmission pipeline location data (10/5/2020)

3.1 Could FEI undertake capacity-related DSM measures specifically targeted at those communities likely to experience a capacity shortfall? Please explain why or why not.

3.1.1 If yes, to what extent has FEI considered this option?

Response:

Please refer to the responses to BCUC IR1 2.6.1 and BCSEA IR1 8.1.

4. Reference: Exhibit B-1-2, pages 26 and 28

> **3.3.1 Capacity Shortfall Will Negatively Impact Residential and Commercial Customers**
>
> FEI's customer profile in this region has evolved over time such that it has fewer large interruptible industrial customers like pulp mills that can be quickly curtailed in a supply emergency. This means that the necessary curtailment volumes to make a meaningful difference in load have to be obtained from a larger pool of smaller non-interruptible or firm customers. Consequently, any capacity shortfall would predominantly impact residential, commercial (e.g. restaurants and shopping malls), and institutional customers (e.g. schools, hospitals, and community centres).
>
> The first regions to experience a capacity shortfall would be the communities of West Kelowna, Lavington, and Lumby (shown in Figures 3-8 and 3-9 above). The systems in these

4.1 Please identify any interruptible schedules that are available for commercial ratepayers.

4.1.1 Has FEI considered introducing more interruptible schedules for non-industrial ratepayers? Please explain.

Response:

FEI's interruptible or partially interruptible rate schedules are Rate Schedules 7, 27 and 22/22A/22B.

FEI's interruptible schedules are available to commercial and industrial customers as long as they meet the tariff's conditions of service within each rate schedule. FEI has not considered introducing more interruptible schedules as the current interruptible rate schedule offerings cover service requirements for all types of commercial and industrial customers. Rate Schedules 7 and 27 would be the interruptible rate schedules that require the lowest annual consumption from an economic perspective to recognize annual savings when compared to firm service. These rate schedules do not have a minimum required consumption as a condition of service for a customer to qualify, however a customer would need to consume at least 4000 GJ annually when comparing bundled interruptible Rate Schedule 7 vs firm Rate Schedule 3 and 4700 GJ annually when comparing interruptible Rate Schedule 27 vs firm Rate Schedule 23. These are the rough breakeven points between firm and interruptible service however this does not take into consideration any additional costs (i.e., alternative fuel supply, alternate fuel storage costs, and gas equipment burner upgrades) that a customer may incur as a result of electing interruptible service.

5. Reference: Exhibit B-1-2, pages 28 and 29

> ### 3.3.2 The Project is Necessary Despite Uncertainty in COVID-19 Impacts
>
> 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. Furthermore, there is no firm evidence to confirm that any decreases in overall gas demand will be long lasting. Due to this inability to predict what the lasting impacts may be, FEI does not believe that the execution of this critical system capacity addition project should be deferred due to the COVID-19 pandemic.
>
> In the near term, COVID-19 may result in commercial loads declining due to business closures (in compliance with public health orders or resulting from general economic conditions). However, there are also some factors that may mitigate the economic impacts of COVID-19 as they relate to peak load forecasting. For example, FEI expects there to be some offsetting increase in residential heating loads, due to individuals working from home or spending more time at home. Further, some impacts will be temporary and may be resolved quickly, but FEI cannot forecast the timing and magnitude of full recovery. At this time, FEI has no information available to quantify the impact on other customer classes or economic sectors.
>
> FEI noted above a number of possible factors that could act to increase load above the load forecast presented above, including expanding greenhouse operations, winery operations and new CNG fuelling stations, along with other industrial customers. Since the occurrence of COVID-19, FEI continues to receive inquiries and requests for preliminary planning for several projects. FEI cannot conclude that COVID-19 will result in the deferral or cancellation of these potential additional loads.
>
> 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 capacity and that the OCU Project should proceed as set out in this Application.

5.1 Please confirm that the peak demand load forecast is based on the best available information.

Response:

Confirmed. Please also refer to the response to BCUC IR1 1.2.

5.2 Please confirm or otherwise explain that the peak demand load forecast being relied upon in this application has been approved by the Commission, and please identify in what proceeding this peak demand load forecast was approved.

Response:

Not confirmed. FEI has not used the 2019 peak demand forecast in any other approved capacity related applications However, as explained in Section 3.3.1 of the Updated Application, the peak day demand forecast methodology that FEI used to assess the need for the OCU Project is consistent with the methodology FEI has used in its previous long-term gas resource plans (LTGRP) filed with and accepted by the BCUC. Based on this accepted methodology, and since the 2017 LTGRP, FEI has developed its most recent peak demand load forecast, which indicates that increases in population and the increase in gas use by all types of customers will lead to a shortfall in ITS capacity by the 2023/2024 winter peak demand period. If this situation is not addressed through the proposed OCU Project, capacity shortfalls and the resulting curtailment of customers will become increasingly likely and widespread.

5.3 Please provide quantification of the impact of COVID-19 on FEI's load relative to its 2020 load forecast and January 2021 load forecast.

Response:

Please refer to the response to BCUC IR1 1.2.

5.4 Please describe what additional drivers could potentially cause increases or decreases in the load above or below the peak demand load forecast.

Response:

FEI discussed potential increases in peak demand in the referenced section of the Updated Application. In addition, economic drivers related to the cost of energy can impact peak load through the level of customer attachments. For example, the current favourable cost of natural gas relative to other fuels could drive new industrial customers to attach or existing customers to add gas equipment thereby increasing load. Alternatively, government policies promoting forms of energy other than natural gas could decrease load as natural gas customers choose other sources for their energy needs. In the case of industrial customers, since changes in demand can cause changes in local requirements for capacity upgrades, FEI's approach is to incorporate the location and magnitude of changing industrial demand in a responsive manner rather than a speculative manner. Therefore, FEI includes these known industrial load increases or decreases in the first year or two of the load forecast but only where the specific local need is clearly defined.

For changes that might affect the UPC_{peak} of forecasted customer groups, please refer to the responses to BCUC IR1 5.2 and 5.2.1 on contributors to increases or decreases in UPC_{peak} over the forecast and FEI's approach to addressing those factors over time in the peak demand forecast.

5.5 Please describe the economic or other drivers that would potentially cause increases in the load above the peak demand load forecast.

5.5.1 Why has FEI not already included these factors in the peak demand load forecast?

Response:

Please refer to the responses to CEC IR1 5.4 and BCUC IR1 5.2 and 5.2.1 for a discussion of how FEI addresses these factors.

6. Reference: Exhibit B-1-2, page 29

> **3.4 *ITS DELIVERY CAPACITY MUST BE INCREASED TO MEET FORECAST DEMAND***
>
> FEI is committed to providing reliable service to its customers. As such, the inability to reliably serve customers due to a shortage of capacity on the ITS during an expected 1 in 20 year weather event is considered unacceptable.
>
> FEI must also maintain adequate system capacity such that customer additions can be accommodated. Section 28 of the UCA states that a utility must provide service upon request, should the supply line be near the property requesting service.[12] Without an increase in ITS capacity, FEI will be unable to satisfy future growth in gas demand caused by new customer additions.

6.1 When considering the potential for a '1 in 20 year' weather event to occur, how does FEI account for the possibility of climate change to vary the weather from that included in historical data? Please explain.

Response:

Please refer to the responses to BCUC IR1 8.3 and 8.4.

7. Reference: Exhibit B-1-2, page 30

> **3.5 CONCLUSION**
>
> The population and consequent development in the Okanagan region has grown since the ITS was initially constructed in the 1950s. Over time, upgrades to the system have been undertaken to maintain reliable gas supply to the surrounding communities. The most recent major upgrade was in 2000, and since then, the population has increased significantly in the major centres of Vernon, Kelowna and Penticton. FEI's recent forecasts indicate that this increase in population and the increase in gas use by all types of customers will lead to a shortfall in ITS capacity by the 2023/2024 winter peak demand period. If this situation is not addressed, capacity shortfalls and the resulting curtailment of customers will become increasingly likely and widespread.
>
> FEI examined several alternatives to address this situation. The solution proposed in the Application to increase the delivery capacity of ITS is the appropriate response to meet the peak demand requirements in the central and north Okanagan regions, and to ensure that FEI maintains long-term safe and reliable gas service to meet customers' expectations.

7.1 Please provide the historical and forecast population growth for the region dating back ten years and ten years into the future.

Response:

The following table shows the actual (2010 to 2019) and projected (2020 to 2029) population, population growth and population growth rates for the municipalities connected to the ITS. The data is from a report prepared for FortisBC Inc. by BC Stats and is based on the P.E.O.P.L.E 2020 forecast. The data shown was received in February 2021.

Year	Population	Population Growth	Population Growth Rate
2010	571,599	(2,108)	-0.4%
2011	575,876	4,277	0.7%
2012	579,665	3,789	0.7%
2013	584,355	4,690	0.8%
2014	595,951	11,596	2.0%
2015	606,378	10,427	1.7%
2016	615,377	8,999	1.5%
2017	636,687	21,310	3.5%
2018	651,495	14,808	2.3%
2019	659,861	8,366	1.3%
2020	666,419	6,558	1.0%
2021	671,549	5,130	0.8%
2022	677,570	6,021	0.9%
2023	684,147	6,577	1.0%
2024	690,838	6,691	1.0%
2025	697,432	6,594	1.0%
2026	703,918	6,486	0.9%
2027	710,312	6,394	0.9%
2028	716,590	6,278	0.9%
2029	722,737	6,147	0.9%

7.2 Please provide FEI's customer account history (number of accounts) for the last 10 years by rate class.

Response:

The following table shows FEI's customer totals by rate schedule for the communities served by the ITS for years from 2010 to 2019.

Rate Schedule	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	159,237	160,574	158,496	161,510	163,966	166,843	169,459	172,588	176,579	180,210
2	15,605	15,809	15,210	15,582	15,868	16,082	16,254	16,404	16,613	16,787
3	533	533	526	472	471	460	466	511	628	685
4	10	10	10	1	9	10	1	4	2	2
5	18	16	16	15	15	14	15	15	18	18
6	1	1	1	-	-	-	-	-	-	-
22	7	7	7	5	5	6	7	6	6	6
23	160	164	164	186	188	202	209	210	202	204
25	48	46	46	45	48	52	53	54	51	51
27	11	11	10	12	11	11	10	11	11	11
Total	175,630	177,171	174,486	177,827	180,571	183,680	186,474	189,803	194,110	197,974

7.2.1 Please provide FEI's customer account forecast for the next 5 years to the extent it is available.

Response:

Please refer to rows 278 to 289 in the tab "ITS Accounts" of Appendix L-3 - ITS Account and Peak Day Demand Forecast Details by Rate Schedules.

For convenience, the requested data is reproduced in the table below. FEI has assumed the question is requesting the data for 2022 to 2026 but has also provided the data for 2018 to 2021.

Rate Schedule	2018 YE Accounts	2019	2020	2021	2022	2023	2024	2025	2026
1	176,579	180,210	183,317	186,105	188,751	191,302	193,850	196,269	198,493
2	16,613	16,787	16,964	17,146	17,331	17,516	17,703	17,887	18,075
3	628	685	744	804	865	927	989	1,000	1,012
23	202	204	207	209	212	214	217	220	222
4	2	2	2	2	2	2	2	2	2
5	18	18	18	18	18	18	18	18	18
6	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-
22	6	6	6	6	6	6	6	6	6
25	51	51	51	51	51	51	51	51	51
27	11	11	11	11	11	11	11	11	11
Total ITS System	194,110	197,974	201,319	204,352	207,247	210,048	212,848	215,464	217,890

7.3 Please provide the Use Per Customer by rate class for residential and commercial customers over the last 10 years.

Response:

Please refer to the response to BCUC IR1 5.3.

7.3.1 Please provide FEI's Use Per Customer forecast for the next 5 years to the extent it is available.

Response:

FEI UPC_{peak} values remain constant for the next five years and through the remainder of the forecast period. The values are provided in the Appendix L-3 - ITS Account and Peak Day Demand Forecast Details by Rate Schedules (refer to tab "ITS UPC"). For convenience, the UPCpeak values are reproduced in the table below.

UPC_{peak} Values used in 2019 ITS Peak Demand Forecast

Network Area	3 Year Average UPC for 2019		
	(TJ/d)	(TJ/d)	(TJ/d)
	Rate 1	Rate 2	Rate 3
Armstrong, Spallumcheen	0.00094	0.003348	0.041168
Castlegar, Robson	0.000819	0.0033	0.030106
Chase, Pritchard	0.000916	0.003386	0.036346
Christina Lake	0.000846	0.00212	0
Creston, Yahk	0.000802	0.002622	0.052761
Falkland	0.000934	0.002564	0.026771
Grand Forks	0.000848	0.002754	0.049277
Greenwood	0.00087	0.002207	0
Kamloops, Heffley Creek, Tobiano	0.000961	0.004757	0.039577
Kelowna, Westbank, Oyama	0.000915	0.004228	0.043765
Keremeos, Cawston	0.000839	0.002911	0.061115
Midway, Rock Creek	0.000874	0.003335	0
Nelson	0.000914	0.003331	0.039417
Osoyoos, Oliver	0.000772	0.003097	0.0401
Princeton, Hedley	0.000933	0.00312	0.040626

Network Area	3 Year Average UPC for 2019		
	(TJ/d)	(TJ/d)	(TJ/d)
	Rate 1	Rate 2	Rate 3
Penticton, Naramata, Okanagan Falls, Summerland, Kaleden	0.000818	0.003692	0.039221
Peachland	0.000938	0.003377	0.04047
Salmon Arm, Enderby, Grinrod	0.0009	0.003166	0.030276
Salmo	0.000893	0.003223	0.022704
Sorrento, Blind Bay, Tappen	0.000956	0.002633	0.026077
Savona	0.000955	0.003205	0
Trail, Warfield, Rossland, Fruitvale, Montrose	0.000892	0.003459	0.032363
Vernon, Coldstream, Lumby	0.000906	0.003577	0.031181

1

8. Reference: Exhibit B-1-2, page 32

> **4. DESCRIPTION AND EVALUATION OF ALTERNATIVES**
>
> **4.1 *INTRODUCTION***
>
> As outlined in Section 3, FEI is forecasting load growth in the Okanagan region, which will result in insufficient pressures in portions of the ITS unless a system upgrade is installed. The first impact expected will be the loss of sufficient winter inlet pressures to the Kelowna #1 Gate Station and the Polson Gate Station, which may occur as early as the winter of 2021/2022. With the reduction in inlet pressure, FEI would lose the capability to deliver gas to customers in portions of the Okanagan on winter days that approach system design conditions. The OCU Project therefore 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.
>
> As explained in the following section, FEI has determined that short-term mitigation measures may be required to maintain sufficient capacity for the winters of 2021/2022 and 2022/2023. However, these interim measures are not viable to support projected demand in 2023/2024, and a longer-term solution must be implemented prior to this point.

8.1 Please provide a breakdown of those customers that could be affected by an inability of FEI to deliver gas on winter days approaching design conditions as early as 2021/2022. Please breakdown by rate class of the number of customers and annual energy consumed.

Response:

A customer breakdown is provided below. The industrial customer rate schedules were grouped to protect any individual customer's annual consumption from being disclosed.

Rate Schedules	1	2	3	23	5,25,27
2020 Consumption by Rate Schedule (TJ)	1,321.9	265.1	169.1	44.6	1,334.2
2020 Customer Count by Rate Schedule	16,744	1,095	49	10	6

Note: A small number of seasonal rate schedule (RS4) customers not operating though the winter periods were excluded from this table.

9. Reference: Exhibit B-1-2, page 33

> **4.1.1 Short-Term Mitigation Measures are Possible to Maintain Capacity for Winters of 2021/2022 and 2022/2023**
>
> All alternatives rely on the implementation of short-term mitigation measures to address the possibility of a capacity shortfall during the winters of 2021/2022 and 2022/2023.
>
> Short-term mitigation measures include options such as maximizing the utilization of the currently available capacity within the system by temporarily allowing lower station inlet pressures where existing stations are capable; increased pressure monitoring; minor station upgrades; and CNG injection to offset peak demand where feasible.
>
> While these measures are adequate to provide some capacity safety margin in the winter of 2021/2022 and 2022/2023, they do not represent a viable long-term solution, and do not provide FEI with sufficient and reliable system capacity starting from the winter of 2023/2024. Local measures such as operating stations at lowered inlet pressures provide limited benefit to the system outside their immediate area and do not address the continued decline in system pressures that a pipeline upgrade would address. While CNG injection could also mitigate short-term capacity needs in the region, this is not a viable long-term solution as the volumes of CNG required to meet growing demand continue to increase each year with additional load growth, and due to the significant cost to implement, operate and maintain a CNG supply. More importantly, CNG injection is a far less reliable method to transport gas through B.C.'s Interior than a pipeline, due to reliance on a fleet of CNG trucks, which would need to operate on rural highways in adverse weather conditions.

9.1 Please elaborate on the temporary allowance of lower station inlet pressures.

9.1.1 What is the impact of this option on other customers?

9.1.2 Why can this only be a temporary measure?

Response:

In the response to BCUC IR1 2.5, FEI presented Figure 1 which shows the inlet pressure to the major gate stations to be declining under forecast peak demand conditions in the absence of the OCU Project. Two stations in the Central and North Okanagan (Polson and Kelowna #1 Gate Station) are the most critical. The figure also shows that, under peak demand, the inlet pressure will be at or below 350 psig at these stations in winter 2020-2021 and without the OCU Project the inlet pressure will continue dropping at a rate of more than 40 psig per year. Until the Project is complete, FEI will be required to make some temporary allowances to mitigate the impact of increasingly low station inlet pressure and maintain gas supply and reliable service to all customers. The temporary allowances or short-term mitigation measures do not address the overall decline in system pressure. This decline in pressure is driven by customer growth and the associated increase in peak demand each year. Therefore, the allowances are only short-term. The following elaborates on the allowances each year until the OCU Project is expected to be in service.

Winter 2020-2021:

- FEI has confirmed that under peak demand, although the inlet pressures at the Polson and Kelowna #1 Gate Stations are below standard minimums, the stations do have capacity to operate at the available pressure and still function normally.

Winter 2021-2022 (until Project completion):

- FEI will shift load off the Kelowna #1 and Polson Gate Stations through system configuration adjustments (to be in place all winter) The effectiveness of this support is limited by the capability of downstream distribution systems to distribute the load. The load reconfiguration slows the pressure decline at the critical stations by reducing the flow in the lateral pipelines.
- FEI will lower the operating pressure of the downstream IP systems below 300 psig to ensure that the differential across the station remains sufficient for normal operation at the reduced inlet and outlet pressures.
- Some regulating stations in the downstream system will need modification to allow operation at the lower pressures reliably.

Winter 2022-2023:

- In addition to the above, FEI is installing full-size bypass piping around the Polson and Kelowna #1 Gate Stations to be opened and controlled locally, only as necessary, on a peak day. The bypass will avoid the larger pressure drop caused by flow through the station. This approach will require Operations personnel to be present at the station sites to facilitate operation of these bypasses on a peak day.
- This will continue to support peak demand for 2022-2023. Some commercial and industrial customers may be impacted through temporary load management for any new or added loads. No other customers will be impacted.

With successful execution of the temporary allowances described above, no other customers on the ITS in the Capacity Shortfall Region or elsewhere will be impacted by low pressure or loss of supply.

9.2 Please describe the increased pressure monitoring and how that assists.

Response:

Pressure monitoring will be added to the system at key points in the system. Generally this increased pressure monitoring, transmitted to FEI Gas Control, will be installed at the inlets and outlets of certain stations and locations in the weakest points of the distribution systems. These

points are not currently monitored, and are on the tail-end of the system; therefore they will experience low pressure first in the event of design day peak demand on the system. This will provide FEI with some advance notice that pressures in the system are dropping to critical levels and assist in the deployment of FEI Operations resources. This is critical as certain mitigation measures require manual intervention, such as operation of manual station bypasses.

9.3 What minor station upgrades would be required? Please explain and elaborate on what they would contribute to mitigating the issue.

Response:

FEI plans minor upgrades to the pressure regulator installations of the following stations at the tail-ends of the Kelowna and Polson IP systems to increase their capacity:

- Westbank IP/DP Station;
- Peachland IP/DP Station; and
- Lavington IP/DP Station.

FEI also plans to install full bypasses on the following stations to allow manual bypass of these stations when inlet pressure drops sufficiently low:

- Kelowna #1 Gate Station; and
- Polson Gate Station.

This will allow transmission pressure gas from upstream of the stations to flow directly into the downstream IP systems without a pressure drop through station equipment, improving pressures in these IP systems. For safety reasons, this is allowable only when the inlet pressure drops below the maximum allowable operating pressure of the IP pipelines downstream, and will require careful planning and monitoring by operations personnel.

9.4 Please elaborate on the CNG injection option. Would that be used in conjunction with the other mitigating options, or independently?

9.4.1 Could use of significantly increased CNG independently resolve the issue? If so, for how long?

Response:

Please refer to the response to BCUC IR1 11.1.

10. Reference: Exhibit B-1-2, pages 33, 42 and 45

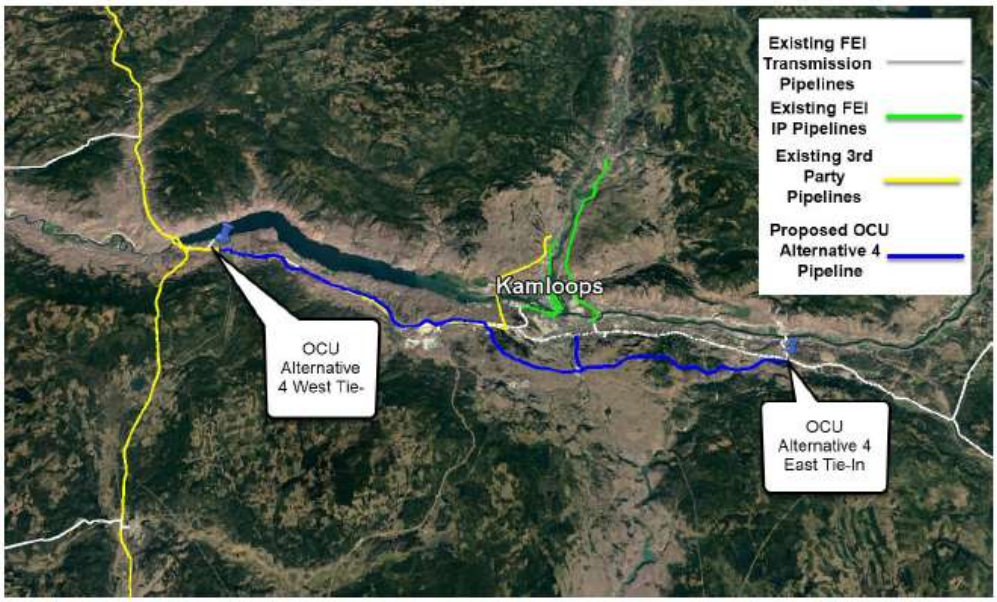
FEI conducted a comprehensive evaluation of these five alternatives and concluded that Alternatives 4 and 5 do not meet the primary project objectives and are not feasible to implement within the timeframe required to meet capacity requirements. These alternatives were therefore screened out early in the project development phase. The remaining three feasible alternatives (Alternatives 1 through 3) were further analyzed and evaluated using the evaluation criteria specified in Section 4.4.1. These criteria include improving operational flexibility, minimizing impact to the environment and the public, as well as financial criteria.

4.2.4 Alternative 4 – 508 mm Loop from Savona

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.

This pipeline looping would increase gas supply delivered via the Enbridge pipeline at Savona. This alternative would also require an upgrade to the 4.1 km 114 mm Coldstream lateral in Vernon to a 168 mm pipeline. Figure 4-5 below provides an overview of Alternative 4.

Figure 4-5: Overview Map of Alternative 4



Source: Google Earth overlaid with FEI Transmission Pipeline Data (Image taken 10/5/2020)

The new pipeline would be designed such that it could be operated at a MOP of 6,619 kPa to match the outlet pressure of the Savona Compressor Station.

Only the first 52.4 km of this loop would be required to be in-service by winter of 2022/2023 to avoid the forecast shortfall. However, the preliminary route chosen for this loop bypasses the City of Kamloops which does not allow for a tie-in to the existing ITS at the 52.4 km mark. Therefore the entire loop would need to be built before it could be tied into the existing system.

(EA)[15]. The anticipated timeline for completion of an EA is three years. Due to this delay, it is highly unlikely that construction of this pipeline could begin prior to 2024. Pipeline installation is likely to take approximately three years due to the length and complexity of this pipeline route, indicating a completion date of 2027 or later. A capacity shortfall which requires significant, lasting mitigation is expected to occur in the winter of 2023/2024; this shortfall will increase each year during the EA and construction phases, as demand on the ITS continues to grow. As discussed in Section 4.1.1, measures such as CNG injection, which can be used to mitigate a small, short-term capacity shortfall such as the shortfall projected for 2021/2022 and 2022/2023, are costly and inefficient in the long term when compared to standard gas supply methods such as pipelines. Relying on such measures to mitigate a large and extended capacity shortfall, such as the one which would occur during implementation of Alternative 4, represents an unacceptable level of risk for FEI's customers. For this reason, FEI does not consider Alternative 4 to meet the primary project objectives as it does not mitigate the risk of capacity shortfall within an acceptable timeframe.

10.1 Is it fair to say that FEI screened out Alternative 4 primarily because it could not be built in the timeframes required for the winter of 2022/2023?

Response:

Alternative 4 did not meet one of the Project objectives as it could not be constructed within the timeframe required to mitigate the upcoming forecasted capacity shortfall and was therefore screened out as not feasible.

However, as discussed in Section 4.4.2.3 of the Updated Application, FEI expects both a significantly higher cost, as well as almost a doubling of installed pipeline length for Alternative 4 (as shown in Table 4-2 of the Application) without providing any additional capacity benefit as compared to the preferred Alternative 3. As such, FEI expects this would have led to Alternative 4 not being the preferred option, even if it was buildable within the limited timeframe.

10.2 At what point would FEI have needed to conduct its initial analysis to have permitted Alternative 4 to be a viable option?

10.2.1 Why was this not undertaken?

10.2.1.1 Did the regulatory regime influence FEI's decision-making with respect to capital spending with respect to this project in any way whatsoever? Please explain.

Response:

To allow Alternative 4 to be completed on time, FEI estimates that the project would have had to be initiated approximately four years earlier. This would have allowed for a three-year environmental assessment timeline (which often is longer, and is a significant schedule

uncertainty) as well as an additional year for construction (required due to the additional length of the pipeline proposed in Alternative 4 compared to the preferred Alternative 3).

It should be noted that, regardless of whether work started earlier to make Alternative 4 viable from a schedule perspective, Alternative 3 is a superior choice for the reasons listed in response to CEC IR1 10.1. Starting earlier would not have changed that determination.

FEI optimizes the timing for the initiation of major system upgrades as much as is practical to maximally utilize existing system capacity, ensuring that ratepayers receive the maximum value from already installed assets. Alternative 4 is not a cost-effective solution to mitigate the capacity shortfall forecasted on the ITS. Regardless of timeline, Alternative 3 is a more cost-effective choice.

FEI's decision-making and alternative selection process was not in any way impacted by FEI's approved regulatory treatment, as any capital investment to address the capacity shortfall was expected to well exceed FEI's CPCN threshold of $15 million.

10.3 Recognizing that FEI conducted a 'comprehensive evaluation' before screening out Alternatives 4 and 5, please provide a general statement of the benefits of Alternative 4.

Response:

Alternative 4 would meet the capacity requirements for the Project, and would be routed primarily through rural terrain. As such, it would likely cause little disturbance to the public during construction and operation. However, for the reasons explained in response to CEC IR1 10.1, FEI does not consider Alternative 4 to be a feasible solution for the Project.

10.4 Please provide a general statement of the detriments of Alternative 4.

Response:

Please refer to the response to CEC IR1 10.1, which provides the detriments of Alternative 4 and explains why it is not a feasible solution for the OCU Project. As discussed there, Alternative 4 is nearly twice as long as the preferred alternative without providing additional capacity benefit. Additionally, there would be a much higher cost associated with Alternative 4 when compared with any of Alternatives 1, 2, or 3. Alternative 4 would also require an EA, which is expected to add a minimum of three years to the Project schedule as well as schedule

uncertainty, making it impossible to complete in the required timeframe and therefore not meeting the Project's objectives. Finally, Alternative 4 increases the percentage of gas flowing into the ITS from the Enbridge T-South system, increasing FEI's reliance on T-South as its primary source of supply.

11. Reference: Exhibit B-1-2, pages 33, 43 and 45

FEI conducted a comprehensive evaluation of these five alternatives and concluded that Alternatives 4 and 5 do not meet the primary project objectives and are not feasible to implement within the timeframe required to meet capacity requirements. These alternatives were therefore screened out early in the project development phase. The remaining three feasible alternatives (Alternatives 1 through 3) were further analyzed and evaluated using the evaluation criteria specified in Section 4.4.1. These criteria include improving operational flexibility, minimizing impact to the environment and the public, as well as financial criteria.

4.2.5 Alternative 5 – LNG Facility Near Vernon

The fifth alternative proposes setting up an LNG storage and peak shaving facility located between Westwold and Grandview Flats northwest of Vernon. Such facilities located closer to the load centre allow gas to be moved into storage in times of low gas demand when excess pipeline capacity is available, and provide on-system delivery during periods of high demand.

In addition to the LNG storage and peak shaving facility, this alternative would also require an upgrade to the 114 mm Coldstream Lateral similar in nature to Alternative 1 and Alternative 4. Figure 4-6 below shows the location of the proposed facility.

Figure 4-6: Overview Map of Alternative 5

Source: Google Earth overlaid with FEI Transmission Pipeline Data (Image taken 10/5/2020)

4.3.2.2 Alternative 5 Discussion and Analysis

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. As detailed in the discussion of Alternative 4, this represents an unacceptable level of risk to FEI and does not meet the project objective to reliably meet demand on the ITS by the winter of 2023/2024. Therefore, it was rejected in the early development phase of the project.

11.1 Is it fair to say that FEI screened out Alternative 5 primarily because it could not be built in the timeframes required for the winter of 2022/2023?

Response:

Alternative 5 did not meet one of the Project objectives as it could not be constructed within the timeframe required to mitigate the upcoming forecast capacity shortfall and was therefore screened out as not feasible. However, as shown in Table 4-2 of Section 4.4.2.3 of the Updated Application, preliminary cost estimates indicated that Alternative 5 was likely to be significantly more expensive (approximately double the cost of a pipeline solution). This would likely have ruled out this alternative even if it was buildable within the limited timeframe.

11.2 At what point would FEI have needed to conduct its initial analysis to have permitted Alternative 5 to be a viable option?

11.2.1 Why was this not undertaken?

Response:

To allow Alternative 5 to be completed on time, FEI estimates that the project would have had to be initiated approximately four to five years earlier to allow for the time required for the permitting, design, and construction of an LNG facility.

Given the much higher preliminary costs, the complexities associated with permitting for a greenfield LNG facility, and the lack of any compelling system capacity benefits associated with the construction of a new LNG facility in the Interior as compared to the pipeline solution, FEI did not pursue this solution further.

11.3 Recognizing that FEI conducted a ‘comprehensive evaluation’ before screening out Alternatives 4 and 5, please provide a general statement of the benefits of Alternative 5.

Response:

If sized appropriately, Alternative 5 could meet the capacity requirements of the OCU Project by providing peak shaving capacity. Alternative 5 could also provide a source of LNG in the Okanagan region which could have operational and gas supply benefits. Constructing a LNG facility in a single location near to existing transmission pipelines could be less impactful during construction as compared to a constructing a new pipeline.

11.4 Please provide a general statement of the detriments of Alternative 5.

Response:

Please refer to the responses to CEC IR1 11.1 and 11.2, which provide the detriments of Alternative 5 and explain why it was not selected as the preferred solution for the OCU Project. As discussed there, Alternative 5 was expected to be approximately double the cost of a pipeline solution with a lack of compelling system capacity related benefits.

11.5 Please explain whether or not FEI could have a mobile option for LNG injection for any part of its system at any point in time required and, if so, why it does not?

Response:

FEI has used LNG injection or supplementation in the past, as discussed in the response to BCUC IR 11.4.1. 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.

12. Reference: Exhibit B-1-2, pages 45 and 46

> ***4.3.2.3 Alternatives 4 & 5 Capital Costs are Expected to be Significantly Higher as Compared to All Other Alternatives***
>
> As shown in Table 4-1 below, preliminary high level cost estimates[16] for Alternatives 4 and 5 are significantly higher as compared to other alternatives. Because neither alternative met the schedule requirements of the project, FEI did not believe that producing more detailed estimates for these alternatives would be a prudent use of funds. Instead, these two alternatives were screened out, while Alternatives 1, 2, and 3 were investigated in more detail to select a preferred alternative.
>
> **Table 4-1: Preliminary Cost Estimates of All Alternatives**

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

> **4.3.3 Conclusion: Screening of Alternatives**
>
> As discussed above, FEI's alternatives screening process concluded that Alternative 4: 508 mm North Loop from Savona and Alternative 5: LNG Peak Shaving Facility near Vernon could not be completed in time to address capacity shortfalls forecast for 2023/2024, and therefore do not meet the primary objectives of the project. Preliminary high level cost estimates also indicated that both Alternative 4 and Alternative 5 would be significantly more costly as compared to other alternatives considered for the Project. As these two alternatives would not achieve the OCU Project objective to eliminate the capacity shortfall in Okanagan region by winter of 2023/24, they were deemed not feasible and were not considered further in the evaluation process. Alternatives 1, 2, and 3 do meet the primary project objectives, and were therefore evaluated in more detail as discussed below.

12.1 When did FEI make the decision to screen out Alternatives 4 and 5?

Response:

Alternatives 4 and 5 were screened out following completion of a preliminary estimate and schedule, and an evaluation of the costs and benefits of each option identified for the OCU Project. This was prior to initiation of the Class 4 estimate which was completed for the three feasible alternatives. This occurred in the second quarter of 2019.

12.2 What level of AACE cost estimate do the above cost estimates represent?

12.2.1 Please provide a table of the level of project definition, end usage, methodology, expected accuracy range and preparation effort for each of the AACE class estimates.

Response:

As described in footnote 18 of the Updated Application, the preliminary high level cost estimates provided in Table 4-1 are at an AACE Class 5+. The maturity level of project definition deliverables is the primary characteristic to determine the cost estimate class. For each alternative, FEI utilized specific industry AACE Recommended Practice Guidelines to measure the maturity level. The estimating methodology followed stochastic estimating methods such as factoring and gross unit costs from benchmarked projects.

As Alternatives 4 and 5 were significantly more expensive than the lowest cost options and did not meet the schedule requirements of the Project, FEI did not consider that developing more detailed estimates for these alternatives would be a prudent expenditure. Therefore, these alternatives were determined to be not feasible and were not considered further in the evaluation process. Table 4-7 in the Updated Application provides AACE Class 4 cost estimates for Alternatives 1, 2 and 3.

Included below is Table 1 from AACE RP 17R-97 *Cost Estimate Classification System* that provides the level of project definition, end usage, methodology, expected accuracy range and preparation effort for each of the AACE class estimates.

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical +/- range relative to index of 1 (i.e. Class 1 estimate) [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Screening or feasibility	Stochastic (factors and/or models) or judgment	4 to 20	1
Class 4	1% to 15%	Concept study or feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget authorization or control	Mixed but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 75%	Control or bid/tender	Primarily deterministic	1 to 3	5 to 20
Class 1	65% to 100%	Check estimate or bid/tender	Deterministic	1	10 to 100

Notes:
[a] If the range index value of "1" represents +10/-5%, then an index value of 10 represents +100/-50% (at an 80% confidence interval).
[b] If the cost index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%.

Table 1 – Generic Cost Estimate Classification Matrix

13. Reference: Exhibit B-1-2, pages 46 and 48

> ### 4.4.1 Evaluation Criteria
>
> Evaluation criteria were grouped into three primary categories:
>
> - Asset Management Capability;
> - Project Execution and Lifecycle Operation; and
> - Financial.
>
> These categories, and the evaluation criteria within them, are listed and defined below.
>
> Weightings were assigned to the overall categories of evaluation criteria as shown in Table 4-3. Asset Management Capability was weighted the most heavily to reflect the importance of meeting FEI's overall technical objectives. Weighting was split evenly between the other two categories. Both are considered important as they measure various types of impact to the communities affected by the OCU Project. Weightings were also assigned to the criteria within each category, also as summarized in Table 4-3.
>
> **Table 4-3: Evaluation Criteria Weighting**

Evaluation Criteria - Category	Weight (Overall)	Evaluation Criteria - Specific	Weight (Within Category)
Asset Management Capability	40%	System Capacity Increase	50%
		Operational Flexibility	50%
Project Execution and Lifecycle Operation	30%	Environmental, Public, and Indigenous Impacts	45%
		Schedule Risk	55%
Financial	30%	Rate Impact	100%

13.1 Are these Evaluation Criteria the identical or very similar to the Evaluation Criteria that FEI uses in other CPCNs?

13.1.1 If not, why not?

13.1.2 If not, what other criteria may be considered that was not considered in this instance, or what criteria was included that might not be otherwise? Please explain.

Response:

As discussed in response to BCSEA IR1 13.1, evaluation criteria and weightings for any project are selected based on the individual and unique requirements of a specific project. Please refer to the responses to BCUC IR1 22.5 and 22.6 for further information on how FEI determined the evaluation criteria and associated weightings for the OCU Project.

13.2 Please provide details as to how FEI determined the Evaluation Criteria.

Response:

Please refer to the response to BCUC IR1 22.5.

13.3 Are these Weightings identical or very similar to the Weightings that FEI uses in other CPCNs?

13.3.1 If not, why not?

13.3.1.1 If not, what other Weightings may be considered that was not considered in this instance? Please explain.

Response:

Please refer to the response to BCSEA 13.1.

13.4 Please provide details as to how FEI determined the appropriate Weightings.

Response:

Please refer to the response to BCUC IR1 22.5.

14. Reference: Exhibit B-1-2, page 49

> FEI applied a scoring methodology to evaluate all three feasible alternatives. The score assigned for each alternative was based on information provided by SMCI, and validated by FEI internal subject matter experts. The components of the evaluation methodology are described in the subsections below.

14.1 Please confirm the CEC's understanding that SMCI did not provide the scoring.

Response:

Confirmed.

14.2 Please identify who originally did the scoring.

Response:

The scoring was done by FEI based on the deliverables developed during creation of Class 4 cost estimates.

14.3 Please provide the positions of the subject matter experts that validated the scoring.

Response:

FEI's team that validated the scoring consisted of the following:

- Senior Project Manager;
- Manager of Gas System Assets;
- Manager of Regulatory Projects;
- Senior Manager of Engineering Projects;
- Senior Manager of Community and Indigenous Relations;
- Environmental Program Lead;
- Manager of Property Services;
- Manager of Environmental Programs;
- Corporate Communications Adviser; and
- Manager of Community Relations.

15. Reference: Exhibit B-1-2, pages 45, 46 and 55

> **4.4.2.3** ***Alternatives 4 & 5 Capital Costs are Expected to be Significantly Higher as Compared to All Other Alternatives***
>
> As shown in Table 4-2 below, preliminary high level cost estimates[18] for Alternatives 4 and 5 are significantly higher as compared to other alternatives. Because neither alternative met the schedule requirements of the project, FEI did not believe that producing more detailed estimates for these alternatives would be a prudent use of funds. Instead, these two alternatives were screened out, while Alternatives 1, 2, and 3 were investigated in more detail to select a preferred alternative.

Table 4-2: Preliminary Cost Estimates of All Alternatives

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

Table 4-8: Capital, O&M, Property Taxes ($000s)

Particulars	Alternative 1	Alternative 2	Alternative 3
Capital Cost (2019$) (excl. AFUDC)	$195,113	$206,623	$188,149
Capital Cost As Spent (incl. AFUDC)	$220,215	$232,927	$212,906
In-Line Inspection Capital (2019$)	N/A	N/A	$828
Retirement / Removal Costs As Spent	$1,569	$692	Nil
Incremental Annual O&M (2019$)[22]	Nil	$9	$24
Incremental O&M - Integrity Digs (2019$)[23]	N/A	N/A	$140
Incremental Annual Property Taxes (2019$)	$6	$78	$337

15.1 Please explain why the Capital cost estimate in Alternative 1 increased from a maximum of $100 million in the initial analysis to $200 million in the final analysis.

Response:

As typically occurs in the project development process, a Class 5 estimate is based on limited information and assumptions. As the scope of the project was further defined and engineering analysis of each option progressed, FEI developed a better understanding of what was required to construct each of the Alternatives, as well as the associated challenges. For a definition of what is included in Class 5 vs 4 estimates, please refer to the response to CEC IR1 12.2.

A relevant example is the number of discrete revalidation hydrotests that would be required to recertify the line due to the effects of the elevation change as the pipeline continued. With the low-resolution of the Class 5 estimate, it was assumed that few would be required. However, as more detailed analysis was undertaken to support the Class 4 estimate, it became apparent that additional tests were required due to how the strength of the existing VER PEN 323 pipeline would limit the elevation difference as it pertained to the static pressure of the water in the pipeline during the hydrotests.

Limitations and challenges such as these, that are better understood as development continues, resulted in higher costs which were not identified when the preliminary analysis was first completed.

15.2 Please explain why the Capital cost estimate in Alternative 2 increased from a maximum of $130 million in the initial analysis to $232 million in the final analysis.

Response:

Please refer to the response to CEC IR1 15.1.

16. Reference: Exhibit B-1-2, page 47

> **4.5.1.3** ***Financial***
>
> The sole criterion within this category measures the financial impact of the project on FEI's customers. FEI considered the long term rate impact to FEI's non-bypass customers in order to financially compare all three feasible alternatives. This was completed by evaluating the present value of the incremental revenue requirement as well as the levelized delivery rate impact over the 70 year analysis period for each alternative based on the estimated capital cost and operating cost.
>
> - **Rate Impact:** Ability for an alternative to be completed with the lowest possible rate impact. The alternative which minimizes the rate impact to FEI's customers will score the highest.

16.1 For each Alternative, please identify and provide quantification for any costs included in the Financial criterion that are related to managing the Project on a short timeline, or that could have been reduced by having a longer timeline for implementation (for instance, overtime costs, higher pricing for shorter delivery times etc.).

Response:

Additional costs associated with completing each Alternative on FEI's required timeline were included within the Class 4 cost estimates. FEI anticipates all of these costs would also be incurred if the durations were lengthened. Any efficiencies or savings would be negligible and are included within the accuracy range of the estimate.

For example, to shorten project execution, FEI increased the crew make-up and size to meet the timelines by completing multiple spreads concurrently instead of applying overtime during construction. Any extension in timelines would incur similar labour costs, but incur them over a longer construction window.

17. Reference: Exhibit B-1-2, page 46, 47 and 48

4.5.1 Evaluation Criteria

Evaluation criteria were grouped into three primary categories:

- Asset Management Capability;
- Project Execution and Lifecycle Operation; and
- Financial.

These categories, and the evaluation criteria within them, are listed and defined below.

4.5.1.1 *Asset Management Capability*

Criteria within this category measure the success of the alternative in achieving the technical goals of the project now and into the future. As this category assesses the efficacy of the solution in meeting the project objectives, FEI considers this category to be relatively more important, which is reflected in the weighting discussed below.

The factors evaluated within this category are as follows:

- **System Capacity Increase:** Ability of an alternative to increase capacity in the ITS such that supply can be maintained to the Okanagan region under peak demand conditions. Alternatives that provide the greatest capacity increase will score the highest. If two or more alternatives provide a similar capacity increase, the same score is assigned.
- **Operational Flexibility:** Ability of a project to provide FEI with greater operational flexibility to perform inspection and repair work on its system assets. Projects which extend the window during which FEI can complete such work on sections of the ITS will score the highest.

4.5.1.2 *Project Execution and Lifecycle Operation*

Criteria within this category measure risks to project completion, and the impact a project will have during construction and over its lifetime on the communities and environment it affects.

- **Schedule Risk:** Ability for an alternative to be completed on schedule, with few identified risks to achieve the scheduled in-service date. Alternatives which can be completed on time will score the highest. Other alternatives are scored lower.
- **Environmental, Public and Indigenous Impacts:** Ability of an alternative to minimize impacts to the environment, the public (i.e., residents, landowners, customers, local government) and Indigenous communities, both during construction and over the lifetime of the project. Alternatives which effectively mitigate environmental and public safety hazards and which reduce negative impacts on the public, Indigenous communities and other stakeholders during project execution will score the highest.

4.5.1.3 *Financial*

The sole criterion within this category measures the financial impact of the project on FEI's customers. FEI considered the long term rate impact to FEI's non-bypass customers in order to financially compare all three feasible alternatives. This was completed by evaluating the present value of the incremental revenue requirement as well as the levelized delivery rate impact over the 70 year analysis period for each alternative based on the estimated capital cost and operating cost.

- **Rate Impact:** Ability for an alternative to be completed with the lowest possible rate impact. The alternative which minimizes the rate impact to FEI's customers will score the highest.

Weightings were assigned to the overall categories of evaluation criteria as shown in Table 4-3. Asset Management Capability was weighted the most heavily to reflect the importance of meeting FEI's overall technical objectives. Weighting was split evenly between the other two categories. Both are considered important as they measure various types of impact to the communities affected by the OCU Project. Weightings were also assigned to the criteria within each category, also as summarized in Table 4-4.

Table 4-4: Evaluation Criteria Weighting

Evaluation Criteria - Category	Weight (Overall)	Evaluation Criteria - Specific	Weight (Within Category)
Asset Management Capability	40%	System Capacity Increase	50%
		Operational Flexibility	50%
Project Execution and Lifecycle Operation	30%	Environmental, Public, and Indigenous Impacts	45%
		Schedule Risk	55%
Financial	30%	Rate Impact	100%

17.1 The CEC notes that Schedule Risk accounts for 16.5% of the total assessment, and encompasses risk associated with meeting the scheduled in-service date. Would this risk have been mitigated if the project were undertaken sooner? Please explain why or why not.

Response:

FEI acknowledges that there could have been some reduction in Project Execution Risk for Alternative 3 associated with increased flexibility in the schedule. However, as discussed in the response to CEC IR1 10.2, FEI considers that it has filed the Updated Application at the appropriate time after maximally utilizing existing system capacity and comprehensively examining of all potential alternatives to address the Project need.

Regardless, Alternatives 1 and 2 carry a high degree of schedule risk regardless of the timing of the project start due to the potential for cycles of hydrotest failures and associated repairs which would take an unknown length of time. The VER PEN 323 pipeline is necessary to maintain supply to the Kelowna region. There is only a short window of time within the year when demand on the system is low enough that adequate capacity can be maintained without this pipeline in operation. This means that if FEI selected Alternative 1 or 2, there would be a limited construction window during which hydrotesting could take place, after which the pipeline would be required to be operational for the colder portion of the year. Should multiple cycles of hydrotesting failure occur, the VER PEN 323 pipeline may not be operational when required, resulting in a capacity shortfall in the Kelowna area even before the winter of 2023/2024.

17.2 Please identify any of the other Evaluation Criteria that reflect timing risk.

Response:

FEI did not identify any other evaluation criteria that reflect timing risk.

17.2.1 Would FEI have adjusted the weightings for the various alternatives considered if there were no timing issues in meeting the 2021-2024 winters? Please explain.

Response:

FEI notes that Table 4-4 in the preamble above shows weightings for the evaluation criteria and not for the alternatives considered. FEI scored three feasible alternatives against the weightings assigned to the evaluation criteria shown above.

FEI would not have adjusted the weighting for "Schedule Risk" if there were no timing issues in meeting the capacity shortfall, as there is still a significant schedule constraint as described in the response to CEC IR1 17.1. Alternatives 1 and 2 would have received low scores for "Schedule Risk" even without the need to complete the Project within a limited timeframe.

17.2.2 If schedule risk were not a factor in meeting the 2021-2024 winters, how would FEI have weighted Schedule Risk? Please explain.

Response:

FEI's assigned weighting would not have changed. Please refer to the response to CEC IR1 17.2.1.

17.2.2.1 Please identify any other evaluation criteria or weightings that FEI would have altered based on timing risk, and how they would have been changed.

Response:

FEI would not have altered any other evaluation criteria or weightings based on timing risk.

18. Reference: Exhibit B-1-2, pages 48, 49 and 50

> **4.5.2 Scoring and Weighting**
>
> Each feasible alternative was scored against each of the evaluation criteria using a scale from 1 to 5. These scores are defined as shown in Table 4-3.
>
> **Table 4-3: Alternative Evaluation Scoring Definitions**
>
Score	Impact Evaluation*
5	Best choice: very low risk, or; very high opportunity for positive impact
4	Good choice: low risk, or; high opportunity for positive impact
3	Acceptable choice: neutral or moderate risk, or; opportunity for medium positive impact
2	Poor choice: high risk, or; low opportunity for positive impact
1	Worst choice: very high risk, or; no opportunity for positive impact
>
> **For evaluation criteria such as System Capacity Increase, which provides a net positive, extent of positive impact is ranked. For others such as Schedule Risk, in which FEI seeks to minimize negative impact to the public, the extremity of this negative impact is ranked.*
>
> Construction of Alternative 1 will not have a positive impact on operational flexibility, as no additional sections of pipeline will be constructed. The system configuration will remain unchanged. A score of 2 was assigned to reflect this (worst choice, low positive impact).
>
> **4.6.1.3 *Alternative 2: Modified ITS Upgrades to VER PEN 323***
>
> Alternative 2 provides a significant positive capacity impact, fully meeting system capacity requirements, and was therefore awarded a score of 5 for System Capacity Increase (best choice; very high positive impact).
>
> Construction of Alternative 2 will have some positive impact on operational flexibility. The proposed 6 km of pipeline extension will allow a greater weather window in which the segment of the VER PEN 323 pipe running from Ellis Creek to the north tie-in point of the proposed 6 km extension can be shut in for inspection, emergency response, or repair. Therefore, a score of 3 (acceptable choice, medium positive impact) was assigned as the improvement to operational flexibility is limited to a small portion of the ITS.
>
> **4.6.1.4 *Alternative 3: OLI PEN 406 Extension***
>
> Extension of the OLI PEN 406 pipeline further north by 30 km provides a significant positive capacity impact, fully meeting system capacity requirements, and was therefore assigned a score of 5 for System Capacity Increase (best choice; very high positive impact).
>
> Construction of Alternative 3 will have a positive impact on operational flexibility. For a portion of the year, it will be possible to shut in sections of the VER PEN 323 line between Ellis Creek and the north tie-in point of the proposed 30 km pipeline extension for inspection, emergency response or repair. As this is a much longer segment of pipeline than the small section affected by Alternative 2, Alternative 3 received a score of 4 (good choice; high positive impact).

18.1 To the extent that the Impact Evaluation uses the term 'or' in identifying the rationale, FEI's impact evaluation appears to equate 'risk' with 'opportunity for positive impact', please elaborate on why a risk is matched with apparently 'doing more' than what would be otherwise expected from the project (i.e. Alternative 1

is scored 2, or a 'poor choice' even though it does not appear to have any risk factors).

Response:

FEI does not equate risk with the opportunity for positive impact. Two separate definitions are given for each score to reflect the different meanings a score can have. A score of 5 is always positive and leads to the alternative scored a "5" being preferred over an alternative with a lower score against a given criteria.

When considering criteria such as schedule risk, however, FEI felt that assigning a score of 5 could be misleading – this could appear to say that a high schedule risk is a good thing. Thus a possible definition of "low risk" was added to the scoring matrix shown in Table 4-3. This reflects that a high score against a "negative" criteria such as schedule risk actually indicates a low risk.

When considering other criteria, such as "Operational Flexibility," a score of "5" has a different meaning. In this case, a "5" indicates a very high opportunity for positive impact. Thus Table 4-3 provides two different meanings for each score, depending on the evaluation criteria in question.

18.2 Why does the risk evaluation not allow for taking on some risk and getting higher value?

Response:

The evaluation scoring definitions do allow for taking on some risk and getting higher value. Alternatives are scored against all criteria and a final weighted score is used to select a preferred alternative, which takes into consideration scores associated with both risk and potential value. This allows FEI to select the best alternative with high opportunity for positive impact, even if another alternative was less risky in one or more areas.

18.3 Operational Flexibility accounts for 20% of the overall weight, compared to 30% for Financial evaluation, and defines the Asset Management Capability differences between the Alternatives. Please provide quantification for the benefits derived from operational flexibility to support the rankings of 2, 3 and 4 for Alternatives 1, 2 and 3 respectively.

Response:

Please refer to the responses to BCUC IR1 22.2 and RCIG IR1 16.06 for further information on the importance and implications of Operational Flexibility, as well as how it applies to Alternatives 1, 2, and 3.

19. Reference: Exhibit B-1-2, page 51

Table 4-6: Project Execution and Lifecycle Operation Alternative Evaluation

Criterion	Weighting	Alternative 1: ITS Upgrades Score	Alternative 2: Modified ITS Upgrades Score	Alternative 3: OLI PEN 406 Extension Score
Schedule Risk	55%	1	1	3
Environmental, Public and Indigenous Impacts	45%	2	2	3
Weighted Total:*	**100%**	**1.45**	**1.45**	**3**

**Weighted total is calculated for each alternative by multiplying the score for each criterion with its associated weighting, and then summing these scores. The maximum possible weighted total is 5.*

As Alternatives 1 and 2 are similar in their overall strengths and weaknesses, they are discussed together below.

4.6.2.2 *Alternative 1 (ITS Upgrades) and Alternative 2 (Modified ITS Upgrades)*

The existing VER PEN 323 was installed in 1957 and was designed to operate at 6,619 kPa. At the time of installation, this pipeline was pressure tested to 110 percent of its design MOP (7,281 kPa), in accordance with the industry standard in 1957. Since its installation, the areas surrounding this pipeline have experienced population growth, changing the class location[19] and requiring the MOP to be reduced to 5,171 kPa to comply with the requirements of CSA Z662. As described in Sections 4.2.1 and 4.2.2 of this Application, Alternative 1 and Alternative 2 involve the replacement of certain pipeline segments to meet CSA Z662 Class location requirements. In addition, FEI has concluded that, to meet current industry best practices, the existing portions of the VER PEN 323 pipeline that are not replaced in Alternative 1 or Alternative 2 must be requalified by retesting. Retesting would be in accordance with CSA Z662:19 at a minimum of 1.25 times the desired MOP of 6,619 kPa (i.e., 8,274 kPa) prior to recommissioning the pipe at its original MOP of 6,619 kPa.

For Alternative 1 and Alternative 2, SMCI established the boundaries of test segments and the number of test segments required, the time it would take to complete a test, and the risks that are associated with the pressure testing process. Due to limitations on allowable elevation difference on a test section, thirty-three requalification tests would be required in addition to six tests for the replacement segments.

The completion of construction and testing required for Alternatives 1 and 2 is complicated by the fact that VER PEN 323 is a critical portion of the ITS and there are nine months of the year when it cannot be taken out of service. It can only be temporarily shut down between June 1 and September 1, leaving little time to carry out the required testing. Using multiple crews working simultaneously during the three month outage, all work required for either alternative

[19] 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.

can feasibly be performed in two three-month periods (i.e., two years) provided that all activities go ahead smoothly. However, FEI has significant concerns regarding its ability to successfully complete the requalification tests of the existing segments of the VER PEN 323 pipeline, as discussed below.

19.1 What options exist for FEI to mitigate the risks associated with the requalification tests? Please explain.

19.1.1 To what extent did FEI consider these options for mitigation in their risk assessments?

Response:

Other than having multiple crews working simultaneously (as described in Section 4.6.2.2 of the Updated Application), there are no other feasible schedule risk mitigation options for Alternatives 1 and 2 associated with the requalification tests.

FEI considered other options, such as use of CNG/LNG to serve customers to facilitate an outage period longer than three months, but only to the extent necessary to confirm that the residual risks to customer supply were not acceptable to FEI and that the mitigation options would therefore not be feasible.

20. Reference: Exhibit B-1-2, page 54

> The route chosen for Alternative 3 results in a comparatively lower impact on the public and the environment by paralleling existing infrastructure (the VER PEN 323 transmission pipeline and the FBC 73L transmission powerline) wherever possible. This routing reduces the necessity to clear a new right of way, thereby reducing the long-term visual impact to the public in Naramata and Penticton as well as the impact to the environment. FEI anticipates acquiring some new land rights should this alternative be selected. As discussed in detail in Section 8.2 of the Application, FEI is committed to negotiating fair agreements with all landowners along the route and will continue to engage with landowners post CPCN filing to acquire the requisite land rights. If FEI is unable to come to agreement with landowners, it does reserve the right to proceed with expropriation of the required land rights.

20.1 Please confirm that FEI accounted for the cost of acquiring land rights.

Response:

FEI has included the cost of acquiring the necessary land rights in the Project's cost estimate. The cost for acquiring land rights can be found in Confidential Appendix E-2, Schedule 6, Line 31.

21. Reference: Exhibit B-1-2, pages 55 and 56

Table 4-7: PV of Incremental Annual Revenue Requirement and Rate Impact

	Alternative 1	Alternative 2	Alternative 3
PV of Annual Revenue Requirement $000s	$199,969	$213,780	$203,973
Levelized Rate Impact $/GJ	$0.057	$0.061	$0.059
Financial / Rate Impact	4	2	3

The following Table 4-8 summarizes the incremental capital costs, annual operating and maintenance and property tax costs for the three alternatives. For Alternative 3 the incremental integrity capital related to running crack detection tools for in line inspection and the resulting operating costs (i.e., the integrity digs) that occur on a once per seven-year cycle are also provided.

Table 4-8: Capital, O&M, Property Taxes ($000s)

Particulars	Alternative 1	Alternative 2	Alternative 3
Capital Cost (2019$) (excl. AFUDC)	$195,113	$206,623	$188,149
Capital Cost As Spent (incl. AFUDC)	$220,215	$232,927	$212,906
In-Line Inspection Capital (2019$)	N/A	N/A	$828
Retirement / Removal Costs As Spent	$1,569	$692	Nil
Incremental Annual O&M (2019$)[22]	Nil	$9	$24
Incremental O&M - Integrity Digs (2019$)[23]	N/A	N/A	$140
Incremental Annual Property Taxes (2019$)	$6	$78	$337

Although Alternative 3 has higher operating and maintenance (O&M) expense and Property Taxes[24], it has the lowest capital cost which result in lower costs for depreciation expense,

21.1 Please confirm or otherwise explain that the PV of the Incremental Revenue Requirement in Table 4-7 includes all the costs identified in Table 4-8.

Response:

Confirmed, all the costs identified in Table 4-8, except for the Capital Cost in 2019 dollars (because the Capital Cost as Spent is included instead), are included as part of the calculation for the PV of the Incremental Revenue Requirement in Table 4-7. FEI clarifies the Capital Cost in 2019 dollars is essentially the Capital Cost in As Spent dollars before escalation and AFUDC. FEI also clarifies that for the line items of Incremental Annual O&M, Incremental O&M – Integrity Digs and Incremental Annual Property Taxes in 2019 dollars, these are escalated at 2 percent per year in the calculation of the PV of the Incremental Revenue Requirement whereas the figures shown in the table are in 2019 dollars only.

22. Reference: Exhibit B-1-2, page 62

> ***5.3.2.3 Weighting and Methodology***
>
> Each of the evaluation criterion was given a weighted score as outlined in Table 5-2, in order to quantify the relative merits of each option.
>
> **Table 5-2: Pipeline Route Evaluation Weighting[23]**

Criteria	Weighting	Evaluation Considerations
Category 1: Community and Stakeholder Criteria Weighting		
Health and Safety	15	Assessment of the construction zone environment, nature of the planned construction activities and proximity to vulnerable entities.
Socio-Economic	15	Proximity to populated areas, roadway usage impacts, number of commercial accesses impacted, agricultural impacts, etc.
Land Ownership and Use	5	Properties directly impacted during construction and nature of impacts.
Sub-total:	***35***	
Category 2: Environmental Criteria Weighting		
Ecology	5	Natural and environmentally sensitive areas impacted.
Cultural Heritage	5	Culturally sensitive areas impacted.
Human Environment	15	Nature and proximity of visual, noise and vibration impacts, residential accesses impeded, etc.
Sub-total:	***25***	
Category 3: Technical Considerations Weighting		
Engineering	5	Areas of construction difficulty requiring engineering solutions identified.
Construction	10	Type of construction required, pipe installation productivity quantified, length of pipeline and overall construction footprint etc.
Operation	10	Areas of potential operational difficulty identified.
System Interface	5	Complexity of interface and length of pipeline laterals quantified.
Adjacent infrastructure	5	Type of adjacent infrastructure, proximity and spacing, planned infrastructure, using wider road allowance to maximize proximity, etc.
Natural Hazards	5	Preliminary evaluation of the surrounding natural and man-made environment and potential hazards along the route corridor.
Sub-total:	***40***	
Total	***100***	

22.1 Please explain how FEI determined the evaluation considerations.

22.1.1 Did FEI make the determinations internally, or were third parties involved in the decision-making?

Response:

All decision making regarding evaluation considerations was done by FEI internally. FEI determined evaluation considerations in a similar manner to its determination of appropriate evaluation criteria and weightings to select a preferred option. A team of FEI internal subject matter experts provided their input; this formed the basis of Table 5-2 which was further refined

based on meetings between stakeholders. Please refer to the response to BCUC IR1 22.5 for a list of the parties involved in this process.

22.2 Please explain how FEI determined the appropriate weights.

22.2.1 Did FEI make the determinations internally, or were third parties involved in deciding the weightings?

Response:

Weightings were determined as part of the same process that determined evaluation criteria and considerations. Please refer to the response to CEC IR1 22.1.

22.3 Did FEI include financial considerations in establishing the weightings?

22.3.1 If no, please explain why not.

22.3.2 If yes, please explain how the financial considerations were included, in what category, and what weight they were given.

Response:

FEI implicitly included financial considerations by incorporating all factors of routing a pipeline which typically drive costs in a project.

For example, more complex construction practices would cost more than simpler construction practices. FEI would not undertake a project in an environmentally damaging way, and so working in a more sensitive environmental area would be more costly due to the safeguards and restoration required than a less sensitive area. Thus, if a route option scores well (high number) against the various criteria related to complexity of project execution, it will be less expensive than an option which receives poor (low number) scores against these criteria due to the costs associated with mitigating the challenges associated with ensuring successful execution.

For this reason, FEI determined that including an explicit financial criteria would result in counting cost considerations twice.

23. Reference: Exhibit B-1-2, page 67

> **5.3.3 Final Route Development**
>
> The next and final stage of the routing process will involve detailed field investigation of the route and the environment in which the pipeline is to be constructed.
>
> Pipeline detailed engineering, geotechnical engineering, and environmental specialist review, with appropriate agreements from Indigenous groups, landowners and stakeholders will confirm the locations for mainline pipe, station sites, cathodic protection (CP) sites and main line valve sites.
>
> Municipalities, stakeholders and third parties will be contacted to obtain further details of any known or expected development or encroachments along the route, the location of underground obstructions, pipelines, services and structures and all other pertinent data. Traffic impact assessments will be completed as required in consultation with the City of Penticton and the Ministry of Transportation and Infrastructure. Stakeholder, local jurisdiction and government approval will be obtained in accordance with statutory requirements.
>
> The outcome of the final stage of the routing process will comprise a confirmed pipeline route and complete list of the affected landowners and stakeholders which will facilitate preparation of the construction scope of work and detailed construction execution plans.

23.1 When does FEI expect to determine a confirmed pipeline route?

Response:

FEI anticipates completion of a confirmed pipeline route in November 2021.

The route mapping, surveys, topography, geotechnical investigations, and alignment sheets have been reviewed and approved at the 30 percent design maturity. As outlined in Table 3 of AACE RP 97R-18 *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Pipeline Transportation Infrastructure Industries*, the route for the OCU Project was a required deliverable for a Class 3 estimate. A Class 3 estimate has a level of definition that varies between 10 to 40 percent, but it is common practice in the pipeline industry to finalize deliverables at the 30 percent design maturity level.

As the design progresses to the 60 percent design phase, or as land and right of way negotiations are finalized, minor adjustments to the route alignment can still occur to accommodate new information related to crossing and boring designs or piping discipline drawings.

The final pipeline alignment sheets required as part of a construction package are completed at the 90 percent design maturity.

24. Reference: Exhibit B-1-2, page 68

> **5.4.2 Pipeline Design**
>
> The proposed OLI PEN 406 pipeline extension will operate at 7,826 kPa and be able to provide sufficient capacity to the existing ITS mainline pipeline to support forecast peak demand for the next 20 year period. The proposed OLI PEN 406 pipeline will traverse approximately 30 km in a south to north alignment from Ellis Creek near Penticton to Chute Lake south of Kelowna.

24.1 Please confirm or otherwise explain that the current upgrade means that there will be sufficient capacity along the full length of the ITS mainline pipeline to support forecast peak demand for the next 20 years.

Response:

FEI confirms that Alternative 3, the proposed OLI PEN 406 extension, will provide the necessary system capacity to support peak demand within the forecast 20-year period along the full length of the ITS mainline. Additional support from future compressor upgrades, as described in the Updated Application would be required to deliver gas to the OCU Project pipeline. Alternatively, a means of redirecting gas supply in FEI's transmission system such as that proposed in the Tilbury LNG Storage Expansion Project CPCN application, as discussed in the response to BCUC IR1 12.1, would also support the capacity needs of the ITS.

24.2 If not confirmed, please provide a list of other pipeline or other ITS enhancements that FEI expects will be required to provide sufficient capacity to support forecast peak demand for the full length of the ITS mainline pipeline.

Response:

Please refer to the response to CEC IR1 24.1.

25. Reference: Exhibit B-1-2, page 70

> ***5.4.2.5 In-line Inspection***
>
> ILI is a process that utilizes the pipeline gas flow and pressure to propel an inspection tool within the pipeline. There are a number of types of ILI tools which are used to detect and size a variety of pipeline anomalies, including corrosion, mechanical damage and cracking.
>
> FEI has determined that due to the longevity of steel pipelines, it is appropriate to design the new OLI PEN 406 extension with ILI capability. This will enable cost effective and targeted mitigation of specific pipeline hazards (i.e., corrosion) over the service life of the new asset. Consequently, a receiver at the pipeline outlet (to receive the ILI tool) will be provided during the design and construction. The OLI PEN 406 has an existing launcher at the pipeline inlet (for tool insertion and to control the propulsion) at kilometre point 0.0. For further details see the Project Design Basis Memorandum, P-00760-PIP-DBM-0001, in the Appendix A-1.
>
> To facilitate ILI, the OCU Project pipeline design must incorporate certain features and mechanical components such as avoiding use of tight radius pipe bends, wall thickness transitions, and ensuring that all fittings and appurtenances (e.g. valves, tees) allow for consistent and reliable passage of ILI tools to maximize data collection.

25.1 FEI's Inland Gas Upgrade Project enables in-line inspection with Geometry, Magnetic Flux Leakage and Circumferential tools where the in-line inspection alternative was selected.[1] Please explain whether or not FEI's proposed capability will be consistent with the capabilities of the IGU project.

Response:

The proposed OLI PEN 406 extension will be designed and constructed to allow in-line inspection, consistent with the capabilities of the IGU Project.

[1] FortisBC Energy Inc. Certificate of Public Convenience and Necessity Application for the Inland Gas Upgrade Project ~ Project No. 1598988, Exhibit B-5, Response to CEC IR 1.1.2.

26. Reference: Exhibit B-1-2, page 78

> **5.6.1 Contractor/Consultant Selection and Award**
>
> 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.
>
> Selection criteria will be developed and used to select contractors and consultants that will participate in the various procurement processes. The selection criteria will consider but not limited to items such as previous project experience, project references, Indigenous engagement, performance ability, financial stability, and WorksafeBC standing. Evaluation criteria will be developed and used to award each of the procurement contracts. Evaluation criteria will be unique to each of the contracts, but will generally include key personnel, experience and qualifications, performance ability and understanding of the scope requirement, and cost.

26.1 Does FEI typically use a delivery method utilizing separate contracts for engineering design, construction management and inspection and construction for large scale projects, or is this a novel methodology?

Response:

Please refer to the response to BCUC IR1 24.1.

26.2 What project delivery alternatives did FEI consider, and why were they rejected?

Response:

FEI engaged with Ernst and Young Canada (EY), a multi-disciplinary professional services firm offering consulting services that include, among other things, procurement advice on selecting project delivery method (PDM). FEI selected the PDM by utilizing the in-house Project Delivery Method Selection Framework developed in collaboration with EY. This framework provides a detailed and structured approach for selecting PDMs for FEI's capital projects such as OCU. The Framework is also applied to assess the suitability of Design-Bid-Build when compared to non-standard delivery methods, as was done for OCU, or to re-assess and select a PDM should a project constraint change during the planning phase.

FEI considered following PDMs as part of the evaluation process:

- Design-Bid-Build (DBB)
- Design-Build (DB)
- Construction Manager - At Risk (CM-AR)

- Construction Manager - Agency (CM-A)
- Integrated Project Delivery (IPD)
- Progressive Design-Build (PDB)

The methodology to choose a PDM is based on selecting a method that best addresses the unique characteristics of a project. The various methods are ranked, rather than one being selected over others which are rejected over another, using the procurement objectives, such as timeliness/schedule certainty, cost certainty and risk allocation, to meet as evaluation criteria. The use of procurement objectives allows for a consistent and un-biased comparison of the options, whilst articulating the reasoning for the scoring of each method.

A DBB PDM was selected for the OCU Project primarily because the Project schedule allows for sufficient time to complete the design to 100 percent prior to tendering for the construction contract and achieve schedule and cost certainty.

26.3 Please describe the benefits of the delivery methodology and why it is superior to any alternatives that FEI considered.

Response:

Please refer to the response to BCUC IR1 24.1.2 which provides the pros and cons for the DBB delivery model, and the response to CEC IR1 26.2 for an overview of the methodology used to choose a DBB PDM.

The selected PDM is not superior to any alternative, but rather has advantages over the other methods to successfully deliver the OCU Project based on the Project's scope, scale, characteristics, and risk profile. As explained in the response to CEC IR1 26.2, FEI selected the PDM by utilizing the in-house Project Delivery Method Selection Framework developed in collaboration with EY. This framework provides a detailed and structured approach for selecting project delivery methods for FEI's capital projects.

26.4 Does using separate contracts potentially result in higher costs? Please explain why or why not.

26.4.1 If yes, please quantify the additional costs imposed by this delivery methodology.

Response:

FEI is of the view that using separate contracts or PDMs does not potentially result in higher costs. The cost of a project is based on delivering the scope of work on a pre-determined schedule to meet an objective based on the risk to be encountered during the project's life cycle. Ultimately, a PDM is a procurement approach that defines the relationships, roles, and responsibilities of the parties involved in a project and the sequences of activities required to complete a project.

26.5 If FEI had more time available to complete the Project, would FEI have selected a different methodology? Please explain why or why not.

Response:

FEI would not choose a different PDM if there was additional time available. The DBBPDM is typically the most competitive and commonly used method for pipeline projects.

27. Reference: Exhibit B-1-2, pages 78 and 79

> **5.6.2 Detailed Engineering Design and Land Acquisition**
>
> A consulting engineering firm will complete the engineering detailed design activities. Detailed design activities encompass all engineering calculations, validations, preparation of drawings and bid packages required to cover the Project needs. Detailed design will commence prior to obtaining CPCN approval due to the anticipated durations required for permitting and procuring long lead materials such as valves and pipe that are required in order to meet the proposed construction schedule. Engineering activities will be organized in order of priority, in relation to the fabrication/procurement lead times and the construction schedule.
>
> The Project will require new and expanded ROW, temporary construction working space and access rights. FEI has developed a land acquisition plan to assess the required properties and prioritize the acquisitions based on risk and impacts to the schedule. Further details of the land acquisition are found in Section 8.2.5.3.
>
> **5.6.3 Procurement**
>
> Material required for the Project which have long lead times to fabricate and deliver include items such as line pipe and block valves. Prior to the receiving CPCN approval, FEI will procure all of the long lead material required in order to commence the early works construction in Q1, 2022. Where applicable, FEI will secure the remaining long lead material required for the Project through the contracts established for the early works.

27.1 Please describe the process that FEI will employ to select the consulting engineering firm.

Response:

FEI designed a competitive process to secure the consulting engineering firm. First, FEI developed a Request for Proposal (RFP) detailing the complete scope of services sought from various proponents. Once the RFP was completed, FEI issued the RFP to a short list of six consulting firms based on prior relevant pipeline design work experience and both internal and external references. The proponents were allowed a fixed duration to prepare and submit their proposals. The proposals were evaluated against specific criteria and ranked against each other to determine a shortlist of the top proponents. Through a clarification process and interviews, FEI will fine-tune the evaluation, clarify certain aspects of the proposal, and eventually select a successful proponent.

27.2 Does FEI frequently begin projects prior to BCUC approval? Please explain and discuss the circumstances under which FEI begins projects prior to receiving BCUC approval.

Response:

No, FEI does not begin construction for CPCN projects prior to BCUC approval. However, in order to mitigate any significant project schedule delays, FEI often plans to initiate the detailed design and procurement activities of the long lead material required for its major projects in parallel with the regulatory review process.

27.3 In the event that FEI did not receive CPCN approval for the Project, which party would be responsible for the costs incurred to date? Please explain.

Response:

As discussed in Section 3.4 of the Updated Application, FEI identified the need for the Project in its most recent 2017 Long-Term Gas Resource Plan and began project development to ensure ongoing safe and reliable supply to customers. If a CPCN is not granted for the OCU Project, FEI would request BCUC approval to recover Project costs incurred prior to the BCUC decision from FEI's non-bypass ratepayers. These costs have been prudently incurred to meet the Project schedule requirements driven by forecast capacity constraints and the need to ensure continued safe and reliable gas service to customers in the Okanagan region.

28. Reference: Exhibit B-1-2, page 79

> **5.6.5 Early Works Construction**
>
> The main objective of the early works construction phase is to complete the HDD 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.
>
> To prepare for the HDD, the ROW must first be developed and graded to allow adequate land/space for both of the 820 m long pipe sections to be built. The ROW prep crew will first develop the area around Penticton Creek for the HDD and will then move to the north end of the project (Chute Lake) and begin clearing and developing the ROW working south. This early work is being advanced and is planned to be completed around the bird nesting season and prior to the 2022 wildfire season.

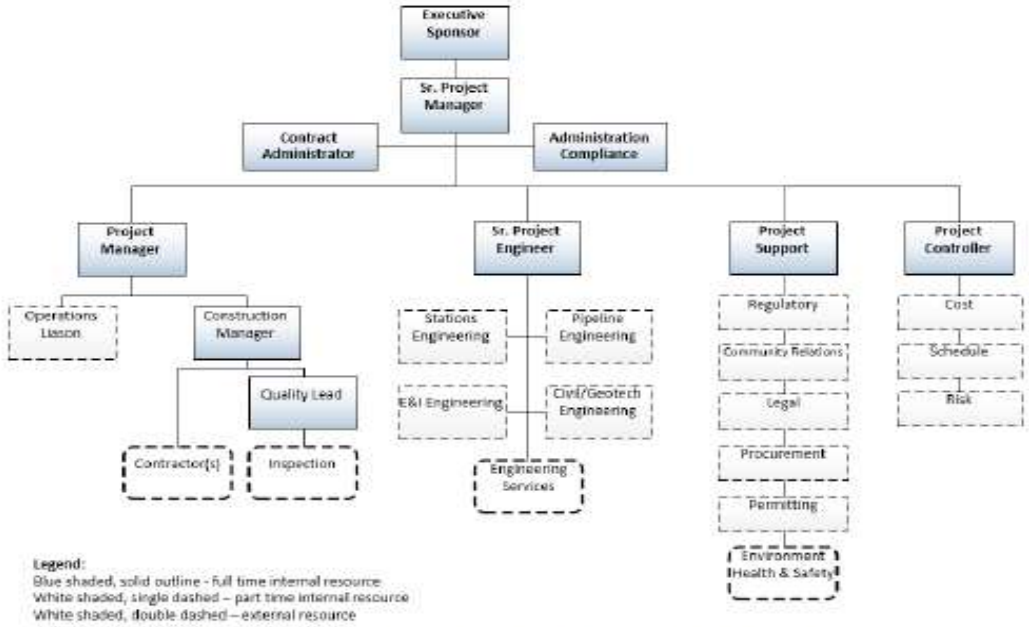
28.1 Might the early works construction also occur before BCUC approval, or would FEI not proceed in the event the approval was delayed or not provided? Please explain.

Response:

As per the requirements of section 45(1) of the *Utilities Commission Act*, FEI would not begin construction of any portion of the Project prior to receiving a CPCN from the BCUC. FEI based the early works schedule around a typical BCUC application review process and decision timeframes with a two month buffer.

29. Reference: Exhibit B-1-2, page 80

Figure 5-4: Proposed Resources and Organizational Chart



The Executive Sponsor for the execution of the Project is the Vice President, Major Projects.

29.1 The CEC is unable to determine definitively which selections would be considered double-dashed and those single-dashed. Please confirm or otherwise clarify if the Contractor, Inspection, Engineering Services and Environment Health and Safety positions are the external resources.

Response:

Confirmed, the Contractor, Inspection, Engineering Services and Environment Health and Safety positions identified in Figure 5-4 above are external resources.

29.2 Please explain why the Environment Health and Safety position is an external resource.

Response:

The Environment Health and Safety (EH&S) role shown in the organizational chart is not solely an external resource. The Senior Project Manager, with oversight by the Executive Sponsor, is accountable for all project activities and is supported by the FEI Project and Construction Managers as well as subject matter leads from FEI's internal EH&S group. These FEI staff are supported by external specialized EH&S resources based on the type of planning or construction activity, such as studies, preparation of management plans, monitoring, auditing,

and compliance reporting. In other words, FEI uses highly specialized external resources to augment its internal resources to provide the required additional capacity and support needed during Project planning and construction.

29.3 Does FEI allocate time for the part-time internal resources to the Project costing? Please explain.

Response:

Confirmed. FEI allocates time within the project cost estimate for those departments that charge time to capital, regardless if part-time or full-time.

30. Reference: Exhibit B-1-2, page 81

> ***5.8.1.2 Ecological Environment***
>
> The proposed alignment of the preferred alternative is located within or directly adjacent to existing rights of way as much as possible. The proposed route overlaps with watercourses, patches of mature trees, and areas with potential for plant communities at risk. Habitat for wildlife or plant species at risk was identified along the proposed alignment of the preferred alternative and surrounding area. Invasive plants are present in the vicinity of the proposed alignment.
>
> The proposed alignment of the preferred alternative was assessed for potential impacts or effects on the ecological environment. Final routing will be selected to minimize disturbance to sensitive environmental features. Best management practices will be applied to minimize any remaining potential negative impacts or effects on the environment. Invasive plant management will be applied throughout construction to minimize the potential spread or introduction of invasive plants. Some vegetation removal will be required during site preparation and construction.
>
> Contaminated sites may be present along the proposed alignment of the preferred alternative. Preliminary studies identified the location and nature of potential contaminated sites. Further studies will be completed prior to construction to identify appropriate handling and disposal techniques.

30.1 Does FEI work directly with the governing regional authority in order to manage the ecological impacts?

30.1.1 If yes, could FEI work jointly with the authority to reduce the invasive plant material rather than simply minimizing potential spread or introduction? Please explain.

30.1.2 If no, why not?

Response:

FEI has been and will continue consulting directly with the governing regional authorities (Regional District of Okanagan-Similkameen and City of Penticton) throughout the Project development and execution phase.

FEI will adhere to all environmental legislation applicable to the Project. Where a governing authority has a specific request regarding managing ecological impacts, FEI will work with the authority to ensure their concerns are addressed in the project Environmental Management Plan (EMP).

Depending on the initiative, FEI would consider working with a governing regional authority if there was an interest expressed by them to address invasive plants within the Project footprint. If the initiative was outside of the Project footprint, FEI would have to consider Project constraints such as impact to cost and schedule.

31. Reference: Exhibit B-1-2, page 82

> There are over 40 wineries along the Naramata Bench. FEI has included these considerations in its route selection process, and as such, has proposed a route that runs alongside FEI's existing VER PEN 323 right-of way and FBC's existing 73 Line right-of way where possible, to minimize the creation of additional right-of-way lands.
>
> 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.
>
> FEI's plans to mitigate, manage and minimize potential short-term adverse effects and monitor Project impacts as construction proceeds. The mitigation measures will be based on industry best practices and applicable requirements of local regulations. To mitigate short-term adverse socio-economic impacts of Project construction, FEI will require the contractor to develop a Public Impact Mitigation Plan. Mitigation measures will include, for example, complying with municipal noise bylaws and limiting traffic access restrictions to businesses and residents during construction.

31.1 For how long does FEI expect its 'short term' impacts to last?

Response:

FEI expects the short-term impacts cited in the preamble to range from a few days to months, but the duration is dependent on the contractor's construction methods. When the contractor is retained, one of their deliverables will be to develop a Public Impact Mitigation Plan that will outline the timing and duration of any such impact(s) to the various stakeholders along the OCU Project pipeline route.

31.2 Will the KVR be shut down completely, or only in sections? Please explain.

Response:

The KVR will be shut down in locations where construction activities pose a hazard to users of the KVR trails. Where possible and practical, FEI will work with the contractor to provide an alternate means around the construction site to maintain the access as a part of its Public Impact Mitigation Plan.

32. Reference: Exhibit B-1-2, page 82

> FEI will also work with Indigenous and local leaders and organizations to identify and mitigate issues, and to connect local workforce and businesses to Project opportunities. Throughout the Project, FEI will endeavor to track the following: Project investment in local Indigenous communities, Project investment in municipalities/regional districts, local employment opportunities, and other community investment activities.
>
> The Project is expected to result in an overall positive impact to residents and businesses through the creation of additional employment, the procurement of local materials, and the use of local services, such as lodging and dining. Further, the Project will benefit the Okanagan region, by helping to meet long-term capacity requirements for a reliable and safe gas system, as population is forecast to increase for the next 20-year period as described in Section 3.3 of the Application.

32.1 In addition to tracking Project Investment in Indigenous communities, municipalities etc., has FEI also established objectives for investment levels that it intends to meet? Please explain.

Response:

FEI is early in the engagement process and has not set specific quantitative targets or objectives for investment levels with Indigenous or local communities. FEI continues to engage with Indigenous and local communities to identify opportunities for economic participation in the project. Generally, these opportunities include contracts for goods and services, or employment with FEI or its contractors.

32.1.1 How can the BCUC determine whether or not the investment levels are appropriate? Please explain.

Response:

FEI's goal is to connect local workforce, businesses and Indigenous communities to existing Project opportunities. Generally, these opportunities include contracts for goods and services, or employment with FEI or our contractors for scopes of work required during the construction of the Project. The purpose of tracking such expenditures (i.e., investments) is to monitor progress and facilitate reporting to the BCUC who is able to inquire into the level of investment by FEI during the course of the Project.

33. Reference: Exhibit B-1-2, pages 87 and 88

> ### 5.10.3 Cost Verification and Validation
>
> Cost estimate quality assurance and validation were completed as follows:
>
> - Internal SMCI reviews that included peer reviews, document quality checks, and independent review;
> - Validation reviews involving both SMCI and FEI team members throughout the estimate development process to confirm that the estimate assumptions were valid; and
> - External independent review completed to verify and validate that the estimate as well as schedule criteria and requirements were met, comparing estimate to the appropriate cost metric and a credible estimate and schedule have been developed for the full construction scope of the Project.
>
> Any material discrepancies or risks identified during the cost validation process were considered during the risk analysis.
>
> ### 5.10.4 Risk Analysis
>
> FEI engaged Yohannes Project Consulting Inc. (YPCI), a company specializing in risk management, to conduct a qualitative risk analysis to identify all of the risks associated with the Project. YPCI conducted multiple workshops with the Project team to develop a risk register for the Project to identify risks that could likely occur.
>
> FEI also retained Validation Estimating LLC, USA (Validation Estimating), a company that provides services in estimate validation, risk analysis and contingency estimation. Validation Estimating completed an escalation estimate and a quantitative analysis using an integrated parametric and expected value methodology based on AACE 42R.
>
> FEI will hold contingency[26], management reserve[27] and escalation funds in addition to the Project base cost estimate as outlined in Section 5.10.1 to address all foreseeable risks. The following sections (5.10.4.1 – 5.4.10.7) outline the methodology used to understand the risks inherent with the Project and the funding required to address the risks.
>
> #### *5.10.4.1 Risk Identification Planning*
>
> The risk identification and qualitative analysis conducted by YPCI was completed using the AACE International Recommended Practice 62R-11: *Risk Assessment: Identification and Qualitative Analysis* (AACE 62R-11, Revision May 11, 2012) as a guide. First, the risks were identified through collaborative discussions between YPCI and FEI through a series of risk workshops facilitated by YPCI. Next, the team developed the risk response actions and the risk likelihood and consequence scales.
>
> The risk likelihood and consequence scales used for the Project are based on the 5 by 5 risk assessment matrix recommended in AACE 62R-11 which is illustrated in Figure 5-5.

33.1 Which company conducted the external independent review, and how was it selected?

Response:

FEI engaged Stantec and Innovative Pipeline Projects Ltd (IPP) to conduct external independent reviews.

Stantec was selected based on its experience and qualifications completing Class 3 estimates for FEI's Inland Gas Upgrades and Transmission Integrity Management Capabilities Projects and their experience and qualifications completing pipeline engineering work for FEI under a master services agreement.

IPP was selected from a list of three qualified firms using a competitive Request for Proposal process. Each proposal was reviewed and evaluated and IPP was selected as the proponent best suited and qualified to complete the work.

33.2 If it was not Yohannes Project Consulting Inc., please explain why not.

Response:

Yohannes Project Consulting Inc (YPCI) is a company that specializes in risk management and it was retained to assist in risk identification and to conduct a qualitative risk analysis of the Project risks. YPCI does not have relevant experience in cost estimating or scheduling.

33.3 What process did FEI undertake to select Yohannes Project Consulting Inc. to conduct the qualitative risk analysis?

Response:

YPCI is an industry recognized expert firm on risk management processes. FEI invited YPCI to submit a written proposal to develop a Project Risk Management Framework. On completion of the framework, FEI invited YPCI to submit proposals for risk management services for the OCU Project. FEI reviewed the proposal for quality, confirmed YPCI's experience through references and evaluated the cost basis. Once confirmed, YPCI was retained through a standard services agreement.

34. Reference: Exhibit B-1-2, pages 89 and 90

> ***5.10.4.3 Quantitative Risk Analysis - Contingency***
>
> Following the completion of the YPCI Risk Report, Validation Estimating completed a quantitative analysis to evaluate the impact of Project specific risks and systemic risks. A Monte Carlo simulation was completed by Validation Estimating to determine a distribution of possible cost outcomes associated with the existing scope of the Project at different levels of confidence. The analysis was conducted using the base Project cost estimate of $187.0 million as outlined in section 5.10.1 above and derived a risk adjusted P50 cost of $213 million representing a contingency of approximately 13 percent. Please refer to Confidential Appendix C-2 for further details on Validation Estimating's contingency methodology and results.
>
> The output of the Monte Carlo simulation, is shown in tabular form in Figure 5-6:

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%

34.1 Please confirm or otherwise explain that the above table is in thousands of $2020.

Response:

FEI confirms that the amounts shown in the table above are in thousands and estimated using $2020 values.

34.2 Without jeopardizing confidential information, please confirm or otherwise explain that a P50 estimate would indicate that there is a 50% chance that the Project cost would not be exceed $213 million, and a corresponding 50% chance that the

Project would not be under $213 million, such that $213 million represents an approximate middle ground estimate.

Response:

Confirmed. P50 represents the 50 percent probability of project cost overrun versus underrun. The estimate is equally likely to be less than or greater than the P50 value, so in other words it is the middle ground estimate or the median value. Note that this amount ($213 million) excludes escalation and management reserve and is different from the cost estimate for the OCU Project, described in Table 6-1 of the Updated Application.

34.3 Is 13% a standard contingency? Please explain and provide quantification of the range of contingencies that are typical.

34.3.1 If not within a typical range, please explain why not.

Response:

FEI clarifies that it does not consider the concept of a “standard contingency” to be appropriate for its major projects. Since each project is unique, FEI calculates a contingency amount specific to each project to achieve a P50 confidence level. In the case of the OCU Project, a 13 percent contingency was applied to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.

35. Reference: Exhibit B-1-2, pages 90 and 91

5.10.4.4 Quantitative Risk Analysis - Management Reserve

Risks with low probabilities and high consequence are not appropriately funded through contingency as they overwhelm the cost and schedule allotments. The cost associated with these types of risks are typically identified and managed as management reserves that the project team cannot spend without the Company's management's approval. Validation Estimating identified two risks which have low probability and high consequence; failed HDD across Penticton Creek, and market costs.

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. As such 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.

During the cost validation process outlined in Section 5.10.3, 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. FEI considered market prices as a risk that could impact the Project cost and undertook additional analysis. The results of the market risk analysis indicate that there is a possible uplift in the price to be quoted by a contractor and FEI retained Validation Estimating to conduct an analysis of the possible uplift in actual bids versus estimate. Table 5-12 outlines the range of possible outcomes resulting from market risk. Please refer to Confidential Appendix C-2 for further details on Validation Estimating's management reserve methodology and results.

Table 5-12: Summary of Management Reserve Monte Carlo Simulation (2020$)

Probability of Underrun	Indicated Risk Funding	
	HDD Failure	Market Risk
5%	10,300	1,300
10%	11,200	2,600
15%	11,900	4,100
20%	12,500	5,600
25%	12,900	7,000
30%	13,400	8,500
35%	13,700	10,000
40%	14,100	11,700
45%	14,500	13,500
50%	14,900	15,300
55%	15,300	17,200
60%	15,700	19,200
65%	16,000	21,300
70%	16,500	23,600
75%	16,900	26,200
80%	17,400	28,800
85%	18,100	32,000
90%	18,800	35,400
95%	19,900	40,200

35.1 Please confirm or otherwise explain that the above table is in thousands of $2020.

Response:

FEI confirms that the amounts shown in the table above are in thousands and estimated using $2020 values.

35.2 Please elaborate on the possible causes of the potential uplift in prices.

Response:

Based on the microeconomic principle of supply and demand, a shortage of qualified and/or competent contractors causes a market risk. The potential uplift in prices arises because many pipeline construction companies that are suitable to build the OCU Project may be actively working on other long-term pipeline projects and hence not have the capacity and/or availability to construct the OCU project. Consequently, there is a risk to FEI that there may not be enough qualified and/or competent contractors and labour and equipment resources available to construct the Project. For example, fewer proponents may choose to compete in an RFP process, reducing competition, and a lack of labour resources could lead to increased salaries. As well, contractors may incur higher costs to subcontract aspects of work they would ordinarily self-perform. Finally, a lack of equipment may require purchasing additional equipment at a higher cost to meet a target completion date. The net result is there is a likelihood that a constrained market could cause an uplift in prices. Please also refer to the response to BCUC IR1 29.1.

35.3 Does the above table indicate a P50 estimate would require a Management reserve of $14,500,000 plus $15,300,000 for a total of $30,200,000? Please explain.

Response:

FEI confirms that a P50 funding level for HDD Failure is $14,900,000 and for Market Risk it is $15,300,000. However, since these two risks are independent of each other the impacts are not summed. The use of the table to determine management reserve is based on the rationale contained in the Confidential Appendix C-4 Validation Estimating Risk Funding Memo.

36. Reference: Exhibit B-1-2, page 91

> ***5.10.4.5 Quantitative Risk Analysis Conclusion – Contingency and Management Reserve***
>
> Contingency is typically expected to be spent and is used as an allocation for risks that are known and likely to be encountered during Project execution. 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.
>
> 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.

36.1 Please confirm that the Market Risk and the HDD Failure risk are not mutually exclusive.

Response:

FEI confirms that the market risk and the HDD failure risk are not mutually exclusive, they are independent. The market risk provision is in place primarily to address increased market costs associated with securing the mainline construction contractor. If the project proceeded with an HDD under Penticton Creek and it failed, FEI would issue the mainline construction contractor a change order to install the gas line using an open trench installation technique. If the market risk also materialized and the mainline construction company costs were higher than originally estimated, then FEI would pay higher than estimated costs to complete the open trench across Penticton creek as well since it would be the same contractor. However, FEI considers the likelihood of both risks occurring is low, as described in the response to CEC Confidential IR1 52.1.

36.2 Do the Market Risk and the HDD Failure risk overlap, such that the Market Risk will be greater if the HDD Failure risk occurs? Please explain.

Response:

Please refer to the response to CEC IR1 36.1.

36.3 Please elaborate on why FEI selected the P70 value of the Market Risk for the management reserve instead of any other value, such as P80 of the Market Risk or adding the two risks together.

Response:

FEI engaged Validation Estimating LLC (John Hollmann), a leading industry expert to conduct a quantitative risk analysis to evaluate the impact of Project specific risks and systemic risks, to develop a contingency estimate, and to confirm the reasonableness of FEI's selection of management reserve at the P70 value of the higher management reserve risk. Mr. Hollmann concluded in the report found in Confidential Appendix C-4, Validation Estimating Risk Funding Memo, page 1, the following:

> The definition of management reserve that does apply to OCU is an allowance for risks "that cannot be effectively managed using contingency". Typically, these are risks with a low probability of occurrence and high potential impact such that if it occurred it would consume much of the contingency. For the OCU project, two such risk events were identified. Given their low probability of occurrence, and having only two such risks, funding one of them (usually the one with the greatest potential cost impact) is appropriate. A p50 value would be acceptable; however, given that there are multiple risks, the p70 value of the larger risk is prudent without being overly cautious. Table 7 of the subject risk analysis report provides the values at various confidence levels.
>
> 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.

37. Reference: Exhibit B-1-2, pages 91 and 92

> ***5.10.4.6 Escalation Risk***
>
> Validation Estimating conducted a cost escalation estimate for the Project. Escalation per AACE is "a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation." The base estimate was developed using 2020 pricing data and conditions and does not inherently account for escalation. Price increases/decreases beyond 2020, including contingency, must be covered by the escalation estimate. As outlined in Section 5.10.4.5, FEI will fund contingency at the P50 confidence level, therefore the escalation estimate is calculated using the risk adjusted P50 cost of $213 million as outlined in section 5.10.4.3 as the basis.
>
> The AACE "by-period" method was applied to develop the cost escalation estimate. This method uses price indices by cost account applied to the annual cash flow by cost account. The base indices are forecasts provided by the economic consulting firm IHS Markit. These indices are used to develop weighted indices that match the cost types (pipeline material, construction labour, etc.). The indices are further adjusted for forecast global and regional capital spending market conditions (i.e., adjusts for bid mark-up behaviour as well as productivity trends in hot or cold markets).
>
> The IHS Markit Q3 2020 forecast is showing minimal cost escalation through 2022 (with the exception of pipe steel) with a slight decrease forecast for the remainder of 2020. However, global and regional capital spending is forecast to rebound by 2022 with the weighted annual price increase forecast to peak at 2.8 percent. The probabilistic analysis, which takes into account the historical standard deviation in price changes from the mean, results in a significant range as shown in Table 5-13. Please refer to Confidential Appendix C-3 for further details on Validation Estimating's escalation methodology and results.
>
> **Table 5-13: Summary of Escalation Monte Carlo Simulation (2020$)**

Base Estimate	$213,059,800	
Probability of Underrun	Escalation	Percent of Base
5%	(9,636,420)	-4.5%
10%	(5,672,540)	-2.7%
15%	(2,885,690)	-1.3%
20%	(146,230)	-0.1%
25%	2,094,160	1.0%
30%	4,198,420	2.0%
35%	6,114,320	2.9%
40%	7,932,070	3.7%
45%	9,716,200	4.6%
50%	**11,611,240**	**5.4%**
55%	13,473,460	6.3%
60%	15,393,410	7.2%
65%	17,470,720	8.2%
70%	**19,522,520**	**9.2%**
75%	21,858,100	10.3%
80%	24,311,300	11.4%
85%	26,931,670	12.6%
90%	30,395,630	14.3%
95%	35,810,570	16.7%

> FEI will fund escalation at $11.6 million which corresponds to the P50 level of confidence.

37.1 Please explain how Escalation Risk differs from Market Risk.

Response:

Please refer to the response to RCIG IR1 23.1 that explains the differences between escalation and market risk and that there is no duplicate provisioning in the Project cost estimate for these risks.

Please also refer to the response to BCUC IR1 29.1 for an overview of the market risk. Market risk covers increased costs to the project stemming from a reduced level of competitiveness when trying to recruit a construction contractor specialized in building gas line projects through mountainous terrain with shallow bedrock.

As outlined in Confidential Appendix C-3, Validation Estimating Escalation Report:

Escalation per AACE is “a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation.” The base estimate reflects Q2 2020. Any price increases/decreases after that point must be covered by escalation. Contingency (less the schedule delay portion), which also has a Q2 2020 basis, is also escalated (contingency cash flow is pro-rated to the base cash flow).

38. Reference: Exhibit B-1-2, pages 94 and 95

> Table 6-2 below includes the financial evaluation of the Project over a 70-year period (65 years post-Project and 5 prior years during the Project)[29]. Details of the financial evaluation of the Project can be found in the Financial Schedules as included in Confidential Appendix E-2.
>
> **Table 6-2: Financial Analysis of the Project ($millions)**

Item	Amount
Total Charged to Gas Plant in Service	$271.3
Total Project Deferral Credit	$(0.8)
Total Project Cost	$270.5
Incremental Rate Base in 2024[30]	$269.6
Incremental Revenue Requirement in 2024	$19.4
Rate Impact in 2024 when all assets enter Rate Base %	2.21%
Levelized Delivery Rate Impact 70 Years (%)	1.62%
Levelized Delivery Rate Impact 70 Years ($ / GJ)	$0.073
PV of Incremental Revenue Requirement 70 years ($ million)	$253.6
Net Cash Flow NPV 70 years ($000s)	$(7.1)

> [29] The 65-year post-project analysis period is equal to the financial life for Transmission Mains as described on page 3-6 of FEI's most recently approved depreciation study. The 5 prior years are related to project development, regulatory approvals, and the construction schedule of the Project from 2022 through 2023.
> [30] 2024 Rate Base is less than the Total Project costs because the 2024 Rate Base also includes the mid-year effect of Accumulated Depreciation and allowance for incremental Cash Working Capital.
> [31] FEI's 2021 AFUDC rate is 5.47%, which is equal to the after-tax weighted average cost of capital.

38.1 Please provide the costs per year (actual and forecast) for the 2018-2023 period.

Response:

For the project capital cost from 2020 to 2023, please refer to BCUC Confidential IR1 2.1. For the capitalized project development costs incurred by FEI in 2019 and 2020, please refer to BCUC IR1 32.3. For the costs related to the Project's CPCN Application and Preliminary Stage Development costs between 2018 and 2021 (actual and forecast), please refer to BCUC IR1 33.1.

38.2 Does FEI include costs related to abandonment or removal in its analysis? Please explain why or why not.

38.2.1 Please provide an estimate of the costs related to abandonment or removal at the end of the 70-year period.

Response:

FEI notes there are no abandonment or removal costs associated with the OCU Project capital costs.

With respect to costs related to abandoning or removing the new pipe at the end of its life, this is collected through the component of FEI's approved depreciation rates that recover net salvage (removal costs). FEI's financial analysis of the OCU Project includes the approved rate for collection of net salvage over the life of the pipeline, as determined by FEI's 2017 Deprecation Study (approved through BCUC Order G-165-20). At the end of the 70-year period, the total amount of provision related to abandonment or removal costs for this Project recorded in the Net Salvage deferral account will be approximately $70 million (Confidential Appendix E-2, Financial Schedule 9, Line 45).

39. Reference: Exhibit B-1-2, page 96

6.3.2 Application and Preliminary Stage Development Costs

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 is seeking approval to record these costs in a new non-rate base deferral account, the OCU Application and Preliminary Stage Development Costs Deferral Account, attracting FEI's after tax weighted average cost of capital until it enters rate base. 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[32]	$(108)	$(244)	$(352)
Capitalized Costs[33]		$(1,682)	$(1,682)
Total Tax Offset	$(108)	$(1,926)	$(2,034)
Financing, WACC after tax	$10	$(73)	$(63)
Total	$302	$(1,097)	$(795)

39.1 Please explain why income tax recovery benefits are deferred into the non-rate base deferral account as opposed to being recorded in the year realized.

Response:

The income tax recoveries **are** recorded in the year realized. This can be seen in Confidential Appendix E-2, Schedule 9, Lines 4 and Line 13 which show by year the Income Tax Recoveries related to the Application and Developments Costs (including the Income Tax offset available for the capitalized development costs). Consistent with past CPCN applications approved by BCUC, the Application and Development Costs are captured by the proposed non-rate base deferral account on a net-of-tax basis (i.e., include the income tax recoveries associated with the Application and Development Costs) and transferred to rate base after BCUC approval. This treatment ensures the net deferred costs/credits will be recovered from/returned to FEI's non-bypass customers following the BCUC's decision approving the deferral account.

40. Reference: Exhibit B-1-2, pages 96 and 97

6.4 *RATE IMPACT*

As discussed above, FEI will complete the Project in 2023. Combined with the amortization of the deferral costs beginning in 2022, the impact to customer delivery rates will change each year from 2022 to 2024[34]. Table 6-4 shows 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.

[32] Income tax recovery on the amount recorded in the deferral account which equals the $400 thousand in costs and the $902 thousand in costs times the Income tax rate of 27%.
[33] 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%.
[34] The first two years of delivery rate impact due to the Project are 2022 and 2023 as a result of the amortization of the deferral credit balance.

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)[35]	2.21%
Delivery Rate Impact (2024) $ / GJ	$0.100
Levelized Rate Impact $ / GJ (2019 – 2088)	$0.073

In conclusion, 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. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an approximate average bill increase of $9.00 per year ($0.100 / GJ x 90 GJ).

40.1 FEI states that the impact to customer delivery rates will change each year from 2022 to 2024. Please provide the delivery rate impact for each year including 2022 and 2023.

Response:

The following table provides: the incremental revenue requirement for 2022 through 2024, the percentage increase (over the 2021 revenue requirement, as applied-for), the delivery rate impact, the typical annual consumption for Rate Schedules 2 and 3 commercial customers, and the approximate change in the annual average bill.

Particulars	2022	2023	2024
Incremental Revenue Requirement $000's	$ (411)	$ (257)	$ 19,448
% increase to 2021 Applied for Revenue Requirement, Non-Bypass (August, 2020)	-0.05%	-0.03%	2.21%
Delivery Rate Impact $ / GJ	$ (0.002)	$ (0.001)	$ 0.100
Typical Annual Consumption / Customer			
Rate Schedule 2 - Small Commercial	340	340	340
Rate Schedule 3 - Large Commercial	3,770	3,770	3,770
Approximate Annual Average Bill Change			
Rate Schedule 2 - Small Commercial	$ (0.68)	$ (0.34)	$ 34.00
Rate Schedule 3 - Large Commercial	$ (7.54)	$ (3.77)	$ 377.00

40.2 Please provide approximate average bill increases for commercial customers by rate class.

Response:

Please refer to the response to CEC IR1 40.1.

41. Reference: Exhibit B-1-2, pages 105 and 106

> ### 7.3.2 Indigenous Community Participation
>
> Notifications were sent to Indigenous communities prior to the onset of the AOA. The notification outlined the intended work and, as noted above, on completion of the draft AOA an opportunity to provide information or comments.
>
> The following communities were contacted as a part of the AOA:
>
> - Esh-kn-am Cultural Resource Management
> - Lower Similkameen Indian Band
> - Nooaitch Indian Band
> - Okanagan Indian Band
> - Okanagan Nation Alliance
> - Penticton Indian Band
> - Upper Nicola Band
> - Westbank First Nation
>
> During fieldwork activities to develop this application, Indigenous communities were invited to participate. Both Penticton Indian Band (PIB) and Westbank First Nation (WFN) participated in PFR activities. Prior to the AIA, Indigenous communities will be notified of the work and provided the opportunity to participate in the AIA.

41.1 Please confirm that the above list represents a complete list of affected Indigenous communities.

41.1.1 If not confirmed, please explain why not and identify any other Indigenous communities that were not contacted as part of the AOA.

Response:

FEI confirms that the list of Indigenous communities and organizations was informed by the Government of British Columbia's Consultative Areas Database (CAD) which identifies affected Indigenous groups.

42. Reference: Exhibit B-1-2, page 106

> A project EMP which will include archaeological specifications, will be prepared and included in the contractor RFP documents. The EMP is also required as a part of the application to the OGC. Environmental Protection Plan(s) specific to the Project, including protection of archaeological, historic heritage and, cultural resources, will be developed by successful contractor(s) prior to commencement of the Project.
>
> If required, archaeological monitoring will be undertaken during all archaeologically sensitive aspects of the work program and the designated archaeological monitor will have "stop work authority" in the event that works underway have the potential to result in unauthorized impacts to archaeological, historic heritage or cultural resources.

42.1 Please confirm that EMP stands for Environmental Management Plan.

Response:

Confirmed. EMP stands for Environmental Management Plan.

43. Reference: Exhibit B-1-2, pages 109, 112 and 113

> **8.2.2 FEI Has Identified Key Stakeholders for Public Consultation**
>
> As part of developing its Consultation and Engagement Plan, FEI identified and consulted with the following stakeholders:
>
> 1. Residents, businesses, FEI's gas customers, and stakeholder groups, all of whom are in close proximity to (and may be impacted by) the Project.
> 2. Landowners who are in close proximity and potentially impacted by the Project.
> 3. Provincial government bodies, including Members of the Legislative Assembly, the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Transportation and Infrastructure, the Ministry of Forests, Lands, Natural Resource Operations and Rural Development, the Agricultural Land Commission, and the BCOGC.
> 4. Federal government bodies, including Fisheries and Oceans Canada, and Environment and Climate Change Canada.
> 5. Local governments including the Mayor, Council, Regional Board members, City Manager and/or staff within the following municipalities and regional district: City of Penticton, RDOS, City of Kelowna, and City of West Kelowna.
>
> Based on feedback from these stakeholders, FEI will continue to refine its communication and consultation methods.

> ***8.2.5.2 Consultation to Date with Stakeholder Groups***
>
> FEI consulted with the following stakeholder groups impacted by the Project and the consultation with these stakeholders is included in the consultation log in Appendix H-2.
>
> - Penticton Area Cycling Association – The Three Blind Mice Trails
> - Penticton Disc Golf Course
> - Naramata Bench Winery Association
> - Naramata Citizens Association
> - South Okanagan Trail Alliance
> - Hoodoo Adventure Company Ltd.
> - Chute Lake Lodge
> - Upper Carmi Neighbourhood Association
> - Okanagan Similkameen Stewardship Society (OSS)
>
> FEI offered to discuss the Project individually with the organizations and local stakeholder groups, and also invited them to participate in the virtual project information sessions. No significant issues were identified in our outreach and there was general support for the Project.

43.1 Did FEI consult with individual businesses, or just associations? Please explain and identify how many businesses FEI consulted directly.

Response:

FEI consulted with individual businesses, in addition to associations. This included consultation with a total of nine businesses classified as landowners along the proposed route (described in Section 8.2.5.3 of the Updated Application). The nine businesses along the proposed route consist of developers, vineyards, wineries, and bed & breakfasts. In addition, FEI consulted with three businesses in proximity to the proposed route, including the Penticton Disc Golf Course,

Chute Lake Lodge, and Hoodoo Adventure Company Ltd. (described in Section 8.2.5.2 of the Updated Application).

43.2 FEI states that it will refine its communications and consultation methods based on feedback. Is FEI open to making changes to its proposal based on customer feedback? Please explain.

Response:

Yes, FEI will refine its communications and consultation methods based on stakeholder feedback. To date, FEI's communications and consultation methods have included the following:

- Meetings, phone calls, and email correspondence;
- Public announcement and information bulletin to local media;
- Project notification letters and information cards;
- Customer communications including bill inserts and information included with natural gas customers' electronic bills;
- Paid advertisements;
- Project website updates; and
- Telephone town hall sessions/virtual information sessions

In addition to continuing to pursue these communications and consultation methods, and other methods proposed by stakeholders, FEI plans to host local in-person information sessions, once COVID-19 safety restrictions are lifted.

44. Reference: Exhibit B-1-2, page 125

> **9.1 *INTRODUCTION***
>
> Section 46 (3.1) of the UCA states that in considering whether to issue a CPCN, the BCUC must consider:
>
> (a) the applicable of British Columbia's energy objectives,
>
> (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and
>
> (c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act* (CEA).
>
> Sections 6 and 19 of the CEA, as referred to in (c) above, do not apply to FEI. FEI addresses the other two requirements below.
>
> **9.2 *BRITISH COLUMBIA'S ENERGY OBJECTIVES***
>
> British Columbia's energy objectives are defined in section 2 of the CEA. Based on the results of the socio-economic assessment described in Section 5.8.2, the 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".
>
> The Project will support this objective by having positive employment impacts and 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. Further, the Project will benefit these Okanagan regions, by helping to meet long-term capacity requirements for a reliable and safe gas system, as some communities are expected to grow by up to 40 percent in the next 20 years.
>
> The work is anticipated to occur in a largely rural landscape, with low population density, and alongside existing rights-of-ways. However, FEI will develop a Public Impact Mitigation Plan, which will outline strategies to minimize community impacts. FEI will also work with Indigenous and local leaders and organizations to develop the local workforce, support local businesses, and connect them to Project opportunities.

44.1 Please identify any areas in which the project is contrary to the energy objectives, and explain why.

Response:

In FEI's view, there are no areas in which the Project is contrary to British Columbia's energy objectives.

Consistent with the BCUC's CPCN Guidelines, FEI notes that the OCU Project may not directly link to the energy objectives defined in section 2 of the CEA, but does not impede or hamper other projects or initiatives undertaken by FEI or others, from advancing these energy objectives. As discussed in the Updated Application, the Project strongly supports energy objective listed in section 2(k) of the CEA "to encourage economic development and creation and retention of jobs". Please refer to the response to BCUC IR1 40.1 that discusses the extent to which OCU Project is consistent with and will advance the BC government's energy objectives.