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August 14, 2023
File No.: 240148.00971/16550

Via Electronic Filing

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. ("FEI") Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project - Final Submission

In accordance with the regulatory timetable in the above-noted proceeding, we enclose for filing the Final Submission of FEI dated August 14, 2023.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by]

Tariq Ahmed

TVA/vde
Enclosure

cc (email only) Registered Interveners

British Columbia Utilities Commission

FortisBC Energy Inc.

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

Final Submission of FortisBC Energy Inc.

August 14, 2023

Table of Contents

PART ONE: INTRODUCTION

1. FortisBC Energy Inc. ("FEI" or the "Company") submits that the Okanagan Capacity Upgrade Project (the "OCU Project" or the "Project"), as described in the updated application (the "Application")[1], Supplementary Filing[2] and responses to information requests ("IRs"), is in the public interest.

2. The population of the Okanagan has increased significantly over the last two decades, and the residential and commercial demand for natural gas has grown along with it. There have also been new industrial loads, including new Compressed Natural Gas ("CNG") fuelling stations, greenhouse expansions and winery operations. Peak demand in the central and north Okanagan has already exceeded current system capacity of the Interior Transmission System ("ITS") and the shortfall is expected to imminently exceed FEI's ability to maintain pressure on the coldest days of the year.

3. A long-term practical solution is required to increase the ITS capacity so that FEI can meet the forecasted peak demand and continue to provide gas service to customers safely and reliably. FEI will otherwise need to resort to curtailing firm customers during peak periods to maintain pressure and preserve supply to remaining customers. Leaving firm service customers without gas for heat, hot water and cooking or industrial processes for multiple days in cold winter conditions is a highly undesirable situation, with potentially serious consequences for these customers. If capacity remains constrained on the ITS, FEI will be unable to continue accepting requests for new service (i.e., new customers, or new loads from existing customers) in this growing region without exposing more customers to a loss of gas service in the coldest winter conditions.

4. The evidence demonstrates that the OCU Project is the most timely and cost-effective way for FEI to continue serving peak loads reliably while also accommodating customer load growth and the anticipated reliability issues as Okanagan load exceeds ITS capacity. The preferred

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1 Exhibit B-1-2.

2 Exhibit B-35.

alternative has the lowest overall impact among the feasible options in terms of technical design, scope, complexity, cost, construction, and environmental, archaeological and societal impacts.

5. In considering this Application, the British Columbia Utilities Commission ("BCUC") is in effect determining what quality of service, per section 38 of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 (the "UCA"), "the commission considers is in all respects adequate, safe, efficient, just and reasonable." FEI is asking the BCUC to approve a Project that will allow FEI to continue providing the uninterrupted service that firm customers in the Okanagan have come to expect, and that customers in the other parts of FEI's system enjoy. The Application also has implications for the duty to serve, as it ensures FEI can continue adding customers that want service in the area. Put another way, the Project avoids the imminent potential for FEI and the BCUC to be faced with making an undesirable – and unprecedented for FEI – choice between: (a) allowing a new customer to connect, or allowing an existing customer to increase load, at the expense of increasing the risk of a winter outage for existing customers, or (b) seeking/granting relief from FEI's obligation to provide service to the potential new customer/new load to avoid increasing the outage risk for existing customers. There is a sound public interest rationale for approving a project like this one that will maintain FEI's longstanding ability to provide reliable service to existing and new customers in the Okanagan.

6. Therefore, FEI respectfully submits that the BCUC should grant a Certificate of Public Convenience and Necessity ("CPCN") for the Project pursuant to sections 45 and 46 of the UCA. The BCUC should also find that the proposed OCU Application and Preliminary Stage Development Costs deferral account is just and reasonable and approve the account pursuant to sections 59 to 61 of the UCA.[3]

7. These Final Submissions are organized around the following points:

- Part Two: The evidence establishes a need to expand the ITS in the near-term to meet load growth in the Okanagan and maintain reliable service.

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3 A draft form of Order sought is included as Appendix J-2 to the Application.

- Part Three: FEI evaluated the relevant alternatives to meet the need for the Project against appropriate criteria. The preferred OLI PEN 406 extension is superior to the other feasible options in a number of respects.

- Part Four: FEI has appropriately defined the Project, estimated costs, and considered and accounted for project risks, all in accordance with the CPCN Guidelines.

- Part Five: The requested deferral treatment for the OCU Project Application and Development Costs deferral account is consistent with prior BCUC approvals and promotes intergenerational equity.

- Part Six: FEI will mitigate environmental and archaeological impacts.

- Part Seven: FEI has engaged with Indigenous Nations and stakeholders adequately and appropriately throughout the course of developing the OCU Project, and will continue to do so.

- Part Eight: The OCU Project is aligned with the applicable British Columbia energy objectives, including by encouraging economic development and the creation and retention of jobs, and plays an important role in addressing the provincial energy and climate objective to reduce greenhouse gas emissions.

PART TWO: THE OCU PROJECT IS NEEDED AND JUSTIFIED TO ADDRESS INCREASED DEMAND

8. The evidence discussed in this Part establishes a clear need to expand the ITS to meet the forecast increase in peak demand throughout the central and north Okanagan regions. This Part is organized around the following supporting points:

(a) Okanagan customers depend on the ITS for service;

(b) Growth in the Okanagan has driven increased gas demand in the residential, commercial and industrial sectors;

(c) FEI is facing an immediate and worsening capacity shortfall despite short-term mitigation, with the real potential to cause customers to lose service in the coldest winter periods;

(d) FEI's peak day demand forecast is based on a methodology that has been used in prior applications and remains appropriate; and

(e) ITS delivery capacity must be increased to meet forecast demand.

A. OKANAGAN CUSTOMERS DEPEND ON THE ITS FOR SERVICE

9. The gas distribution systems in the central and north Okanagan are supplied by the ITS, which consists of approximately 1,515 km of transmission pipeline with a variety of diameters, operating pressures, and in-service dates. FEI's ITS interconnects the gas supply from the Enbridge-owned Westcoast Energy System ("T-South") in the west and the TC Energy-owned Foothills Pipeline in the east. Under typical operating conditions, gas is taken from T-South at the Savona Compressor Station ("Savona") to supply FEI's customers in the Thompson and north Okanagan Regions. FEI's customers in the south and central Okanagan Regions are supplied primarily by the Southern Crossing Pipeline supplying Oliver, which, in turn, supplies pipelines delivering gas through the Penticton area.[4]

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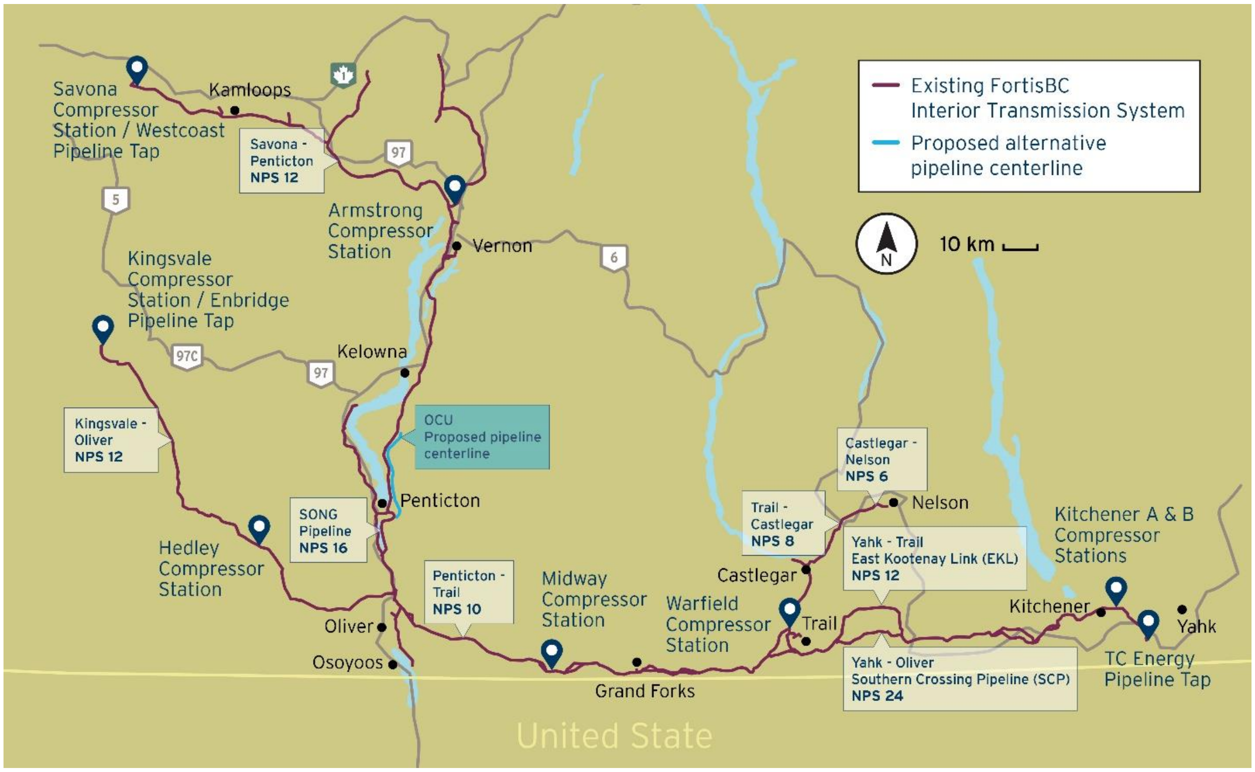
[4] Exhibit B-1-2, Updated Application, p. 11.

Figure 3-1 from the Application[5]



10. Gas systems must maintain certain operating pressures in order to serve customers, and these pressures determine the capacity of the system. FEI expects the minimum pressures experienced across the system, including the ITS, to coincide with the period of highest system demand that occurs on the peak day of the year. Gas flows increase as a result of increased demand on the system. During these conditions, the pressure at any downstream point in the transmission system decreases as distances from supply increase. The rate of pressure degradation increases as flow increases through the pipeline system. Consequently, highest demand inevitably coincides with lowest pressures.[6]

11. As new customers attach to the system, they collectively contribute to increasing demand, producing higher flows and causing lower pressures in the system than would have been experienced on the system in the same weather in previous years.[7]

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5 Exhibit B-1-2, Updated Application, p. 12.

6 Exhibit B-9, BCSEA IR1 1.4.

7 Exhibit B-9, BCSEA IR1 1.4.

12. The need for transmission upgrades like the OCU Project is thus tied to forecasted peak demand and the associated decline in system pressure. FEI's forecasts used for system planning are based on firm demand only, i.e., capacity calculations assume that interruptible load has been curtailed already.[8] In general, FEI can increase the pressure in areas of concern by (a) identifying solutions to meet the required customer demand in a way that can reduce the rate of pressure decline as gas flows through the system (for example, eliminating system bottlenecks), or (b) increasing the pressure available at pressure control points in the system to overcome the higher rate of pressure decrease caused by the increased demand.[9]

B. GROWTH IN THE OKANAGAN REGION HAS DRIVEN INCREASED GAS DEMAND

13. The last major upgrade to the ITS was in 2000,[10] and since then there has been population growth and development in the Thompson, Okanagan, and Kootenay regions, particularly in urban centres such as Vernon, Kelowna, West Kelowna and Penticton. Kelowna, with a population of over 140,000 (including its surrounding area), is now the largest urban centre in the British Columbia Interior. Between 1996 and 2016, Kelowna's population increased by over 37 percent, and it has been one of the fastest growing cities in Canada during the past decade. The average annual population growth rate is 1.6 percent over the past 20 years and growth is forecast to continue for the next 20-year period.[11] The population growth has been accompanied by more commercial and industrial activity.[12]

14. Development in the Okanagan associated with population growth has led to a corresponding increase in the demand for firm gas service, and thus an increased firm demand on the ITS. Increasing industrial load (including greenhouse operations, winery operations, and new CNG fuelling stations, along with other industrial customers on the system) has also

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8 Exhibit B-1-2, Updated Application, p. 21.

9 Exhibit B-9, BCSEA IR1 1.4.

10 Exhibit B-1-2, Updated Application, p. 13.

11 Exhibit B-1-2, Updated Application, p. 16. See also Exhibit B-4, CEC IR1 7.1 and Exhibit B-17, BCSEA IR2 27.1: it can be seen that growth from the referenced years (1996 to 2016) in the City of Kelowna was actually higher than the 1.6 percent reported for the Kelowna region including the Lake Country area.

12 Exhibit B-1-2, Updated Application, p. 16.

contributed to the increase in firm demand. Currently, approximately 60 percent of the demand on the ITS is concentrated in the Okanagan region, which includes Kelowna.[13]

C. FEI IS FACING AN IMMEDIATE AND WORSENING CAPACITY SHORTFALL DESPITE SHORT-TERM MITIGATION

15. After 23 years since the last major upgrade, FEI is now facing an immediate and worsening capacity shortfall. As discussed below, the operating pressure at the midpoint of the ITS, located in the north/central Okanagan (i.e., furthest from the major gas supply points) has declined to the point where a capacity upgrade is necessary to forestall widespread customer curtailments and maintain reliable supply to these areas.

(a) Latest Demand Forecast Confirms There Is Already a Capacity Shortfall that Will Only Worsen

16. FEI recently updated the demand forecast for the ITS in 2023[14] (the "Supplementary Filing Forecast"). The Supplementary Filing Forecast is based on the 2022 Forecast but incorporates actual 2022 year-end core customer attachment and consumption data that was available by the time of the Supplementary Filing.[15] The Supplementary Filing Forecast confirms that (a) peak demand has already exceeded current system capacity, and (b) the shortfall is expected to imminently exceed FEI's ability to maintain pressure on the coldest days of the year.[16]

17. Figures 2-1 and 2-2 of the Supplementary Filing, reproduced below, show the change in peak demand forecast between FEI's Updated Application Forecast (titled "ITS Peak Demand – Updated Application Forecast" in the figure), and the most recent Supplementary Filing Forecast (titled "ITS Peak Demand – Supplementary Filing Forecast" in the figure). The horizontal lines show different representations of the ITS capacity. Figure 2-2 is a magnified extract of the Figure 2-1 graph area within the red box and highlights the imminent need for a capacity upgrade.[17]

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13 Exhibit B-1-2, Updated Application, p. 16.

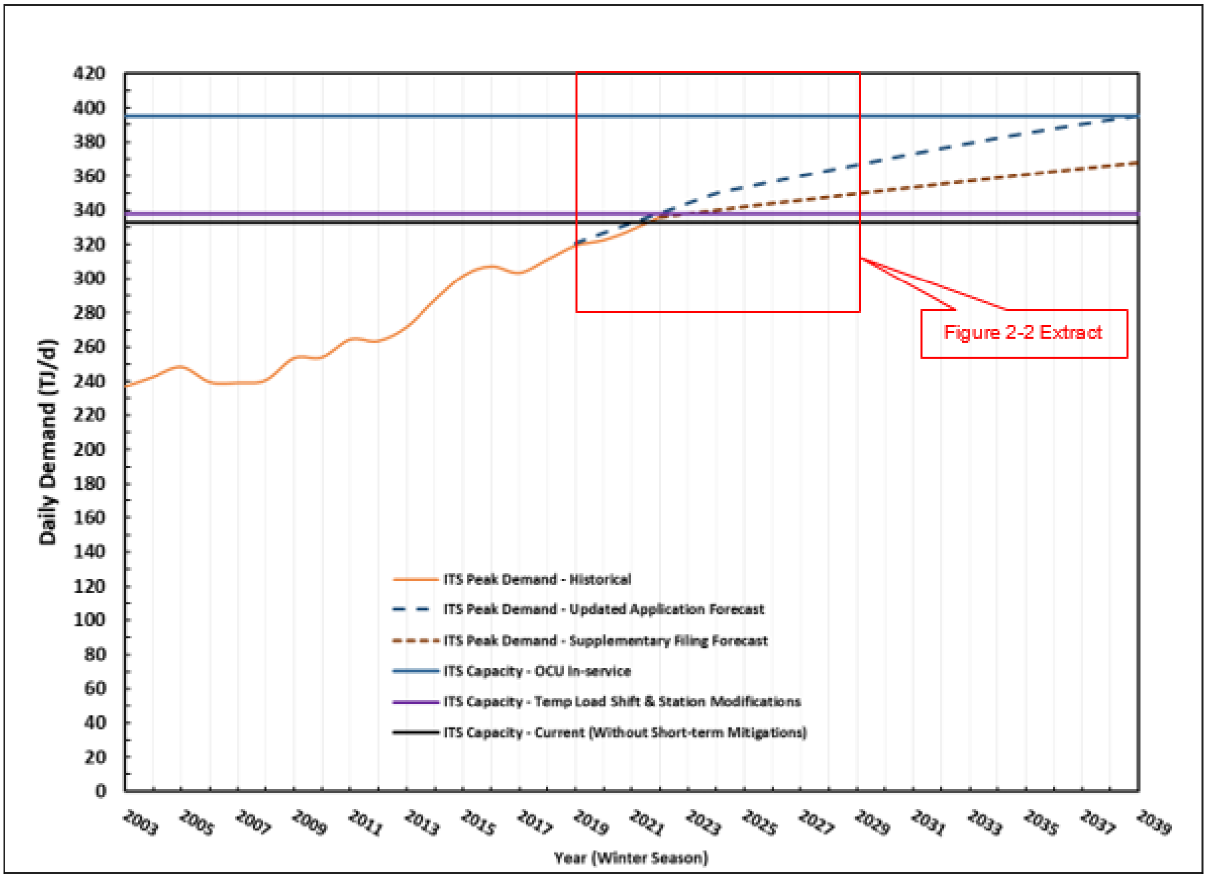
14 Exhibit B-35, Supplementary Filing, p. 3; Exhibit B-36, BCUC Supplementary IR1 1.1.

15 Exhibit B-36, BCUC Supplementary IR1 1.1.

16 Exhibit B-35, Supplementary Filing, p. 3.

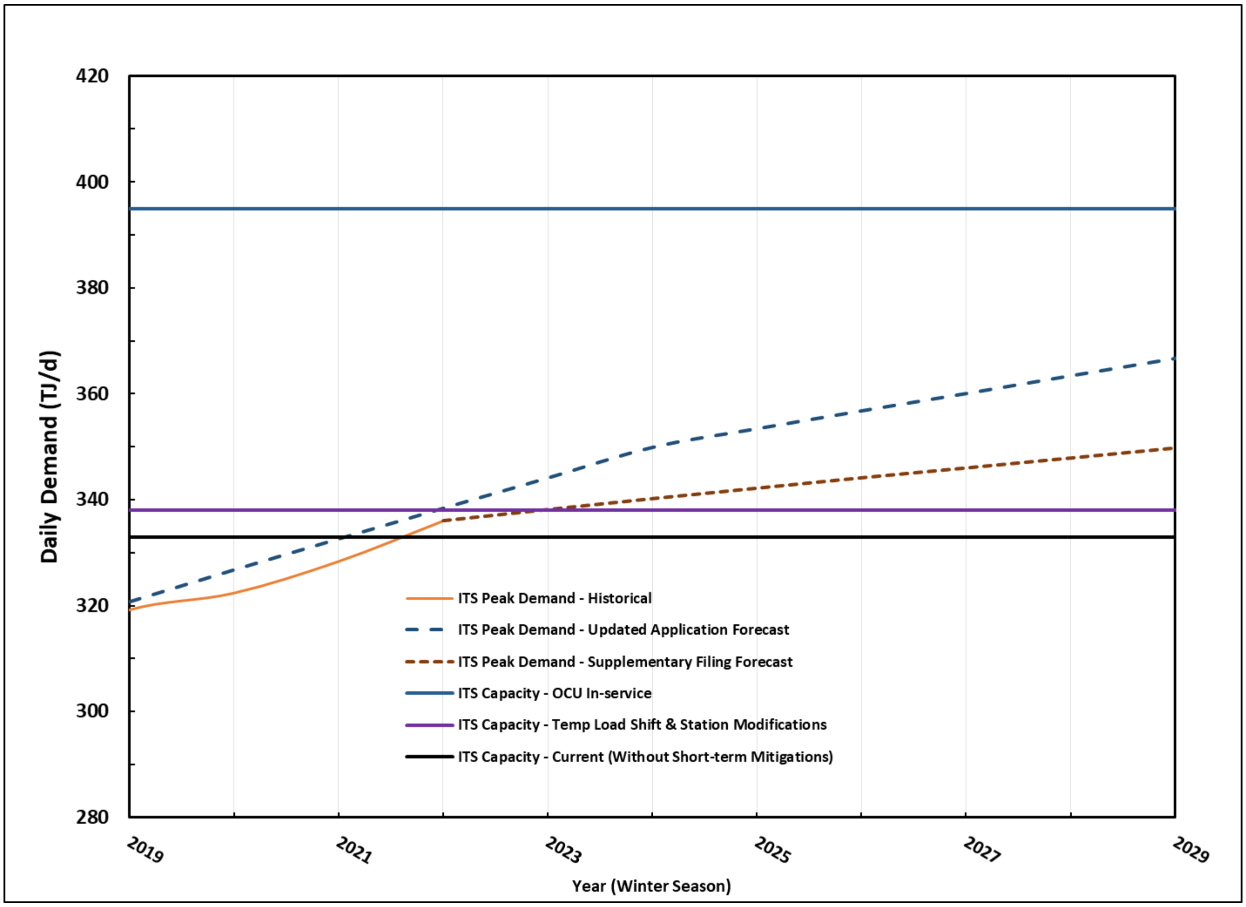
17 Exhibit B-35, Supplementary Filing, p. 3.

Figure 2-1 from Supplementary Filing[18]



[18] Exhibit B-35, Supplementary Filing, p. 4.

Figure 2-2 from Supplementary Filing[19]



18. The historical peak demand for the ITS, titled "ITS Peak Demand – Historical" reflects actual 2022 core customer data. The curve shows the imminent need for the OCU Project, noting that the 2022 historical peak demand exceeds the current ITS capacity.[20]

(b) Short-term Mitigation Measures Are Insufficient to Delay the Need for an Upgrade

19. In the winter of 2022/23, the peak demand exceeded the current ITS capacity. FEI needed to implement short-term mitigation measures to meet demand, which consisted of distribution system load shifting at Polson Gate Station and requesting that Westcoast Energy Inc. ("WEI")

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19 Exhibit B-35, Supplementary Filing, p. 5.

20 Exhibit B-35, Supplementary Filing. p. 5.

increase tap pressure at Savona (where the ITS interconnects with T-South) to 650 psig.[21] However, these mitigations are not a dependable solution, nor are they sufficient beyond 2026.

- First, the Savona tap pressure mitigation is not providing dependable capacity. Although WEI has indicated a willingness to provide FEI with a minimum Savona tap pressure of 650 psig for a limited period, WEI is unable to guarantee that this tap pressure will be available at all times. WEI's inability to provide this guarantee precludes securing a firm contractual obligation in this regard.[22]

- Second, as shown in Figures 2-1 and 2-2 above, demand growth very quickly exceeds the capabilities of the mitigation measures. With temporary load shifting at Polson Gate Station and station modifications in place, the demand is forecast to exceed the ITS capacity this winter (i.e., Winter 2023/24).[23] Even with all mitigation measures in place (i.e., with temporary load shifting, WEI's willingness to increase pressure at Savona and station modifications[24]), the capacity shortfall occurs no later than Winter 2026/27. This coincides with the expected in-service date for the OCU Project. In other words, a delay in the OCU Project's expected in-service date would result in a capacity shortfall in Winter 2026/27, and an inability to serve firm customer load, if design degree conditions are realized.[25]

20. The implications of this capacity shortfall in terms of reduced service for existing customers and FEI's ability to attach future customers is discussed in Section E below.

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21 Exhibit B-41, BCOAPO Supplementary IR1 1.1. See also Exhibit B-36, BCUC Supplementary IR1 9.1.2.

22 Exhibit B-38, CEC Supplementary IR1 2.1; Exhibit B-35, Supplementary Filing, p. 6. See also Exhibit B-36, BCUC Supplementary IR1 10.1.

23 Exhibit B-35, Supplementary Filing, p. 5. This is shown by the intersection of the Supplementary Filing Forecast line and the line titled "ITS Capacity – Temp Load Shift & Station Modifications".

24 Exhibit B-35, Supplementary Filing, p. 6.

25 Exhibit B-35, Supplementary Filing, p. 6; Exhibit B-38, CEC Supplementary IR1 2.1.

D. PEAK DAY DEMAND FORECAST METHODOLOGY IS CONSISTENT WITH PRIOR APPLICATIONS AND APPROPRIATE

21. A number of information requests explored FEI's peak day demand forecast, which is increasing due to increases in the number of residential and commercial customer accounts, and the merits of the underlying methodology.[26] The primary issues raised are addressed below. The evidence demonstrates that FEI's peak day demand forecast methodology, which considers the number of customer accounts and a measure of use per customer, is consistent with prior applications and the approach used by other gas utilities in Canada and the United States.[27] It remains appropriate for determining the OCU Project need. FEI forecasts an increase in the number of residential and commercial customer accounts, and has produced a reasonable forecast for this Application.[28]

(a) Traditional Peak Method Is a Proven Approach and Reasonable for this Project

22. FEI has followed the same system design practices for many years in determining capacity requirements across its service territory.[29] 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 previous CPCN applications and long-term resource plans.[30]

23. FEI's peak day forecast is derived using the traditional peak day forecast method based on actual monthly consumption data, and remains the best available method for determining peak day system capacity requirements. Alternate forecast methods such as the end-use peak forecast method, that explore changes in demand by end-use, remain theoretical, unproven and not fully verified by actual metered data available to FEI. Without, at minimum, direct hourly measurement for residential and commercial customers, FEI has no evidence to verify the reasonableness of theoretical modifications to peak demand based on future end-use changes.[31] FEI intends to continue exploring ways to improve and verify its peak forecasting methods,

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26 Exhibit B-1-2, Updated Application, pp. 20-24.

27 Exhibit B-22, BCUC IR3 65.1.2.

28 Exhibit B-1-2, Updated Application, pp. 20-24.

29 Exhibit B-16, BCOAPO IR2 7.1.1. See also Exhibit B-9, BCSEA IR1 5.1.

30 Exhibit B-1-2, Updated Application, p. 20. See also Exhibit B-6, RCIG IR1 2.1 and Exhibit B-9, BCSEA IR1 5.1.

31 Exhibit B-2, BCUC IR1 4.1 and 4.1.2.

including continued examination of the end-use peak method, as new technology and data becomes available through the Advanced Metering Infrastructure (AMI) program; however, the traditional method remains the best approach for ensuring safe and reliable energy delivery to customers through peak demand events.[32]

24. Using peak day load modified by a transient factor to assess capacity on the ITS, as FEI has done, is more appropriate than peak hour. Due to the available line pack in the ITS, the forecast peak-day load is not dependent on the hour of the day in which the peak occurs in the downstream distribution system, i.e., the determination of coincidence is not directly applicable to the ITS or, by extension, to the Project.[33] On systems such as the ITS, where the configuration provides available line pack, using a peak hour loading would result in under estimating the available capacity and would identify capacity constraints at a lower loading (i.e., earlier in a peak demand forecast) than the system is actually capable of supporting.[34]

(b) FEI's Standard Methodology of Calculating UPCpeak Is Appropriate

25. Under FEI's established methodology, FEI determines the peak demand of residential and commercial customers connected to and consuming gas on the ITS by multiplying the three-year average peak use per customer (UPCpeak) for each rate schedule by the number of current customers in the system in each residential and commercial rate schedule. FEI then multiplies the three-year average UPCpeak for each of the rate schedules by the forecast number of new customer accounts in each rate schedule for each year of the forecast, and adds this to the peak demand for current customers.

26. The formula for calculating a customer's UPCpeak for any customer uses the customer's billing history and actual weather conditions at the customer's premise from preceding years. The objective is to determine the customer's consumption under very cold conditions, much colder than in a normal year, by determining the relationship between the customer's actual consumption and the temperature at the time. The assumption is that the customer daily and

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32 Exhibit B-36, BCUC Supplementary IR1 8.1, 8.3 and 8.5.

33 Exhibit B-16, BCOAPO IR2 8.1.

34 Exhibit B-2, BCUC IR1 3.2.

peak hour consumption will be consistent on any day where the prevailing temperature is the same, whether that day is part of a normal year or a colder than normal or warmer than normal year.[35]

27. The three-year average for UPCpeak reflects an appropriate balance between two competing objectives:[36]

- **A stable value of UPCpeak that does not vary greatly from year to year.** A stable value of UPCpeak will result in a more consistent determination of the projected scope and timing of identified capacity upgrades. FEI uses a process that derives a peak value from monthly customer consumption. Year-to-year variations can occur because of the coarseness of the data (monthly readings). Using a three-year average dampens the year-to-year variations to some degree and provides a more stable and consistent result.[37]

- **Timely recognition of changes in customer utilization.** For example, over time it is reasonable to expect that the average residential customer might become more efficient and the average premise might have a lower UPCpeak due to better insulation, more efficient appliances, etc. Using a ten-year or five-year average would provide a more stable value of UPCpeak, but would obscure more recent changes in customer efficiency from being reflected in the UPCpeak.[38]

28. The UPCpeak values are refreshed annually, and then used in the forecast prepared that year, providing a regular check on the current state of peak demand requirements and potential future impact.[39]

29. In an environment where UPCpeak is increasing, the planning process identifies, year over year, the likely advance in timing of project requirements. The forecast method provides

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35 Exhibit B-8, BCOAPO IR1 2.1.

36 Exhibit B-2, BCUC IR1 5.1.

37 Exhibit B-2, BCUC IR1 5.1.

38 Exhibit B-2, BCUC IR1 5.1.

39 Exhibit B-2, BCUC IR1 5.2.

sufficient notice to initiate project planning and execution, such that projects can be installed to meet the identified capacity deficit. The risk to FEI and its customers of potentially large-scale peak day outages or projects being more costly (due to insufficient planning or execution time) is managed through the traditional method. In an environment where UPCpeak is decreasing, the planning method again identifies, year over year, any deferral in project need, so reprioritization or re-evaluation of the scope of projects can be undertaken. The traditional planning method in this way mitigates the risk to FEI and its customers of investing in capacity projects before the need is present.[40]

30. Recent UPCpeak data for 2020 through 2022 supports the need for the Project in the face of increasing customer growth on the ITS.[41]

31. There is continued consistency in customer usage patterns as they relate to temperature. To the extent there are changes in peak use associated with DSM and changes to building codes, they are not observed through the analysis of customer billing data in preparation of the UPCpeak values.[42] Given the incumbent building stock, changes due to building codes are small and will take some time to materialize.[43]

(c) Net Customer Additions Forecast Reinforced by Recent Experience

32. FEI has used its longstanding approach to determining net customer additions, and the reasonableness of the approach in this context is reinforced by FEI's recent experience. Customer accounts and historic peak demand are keeping pace with that of the Updated Application Forecast.[44] Variations in annual forecast growth rates are often observed and can often be attributable to changes in assumptions pertaining to customer account totals; however, in all scenarios, growth continues to be observed and is expected to exceed existing system capacity

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40 Exhibit B-2, BCUC IR1 5.2 and 5.2.1.

41 Exhibit B-36, BCUC Supplementary IR1 3.3.2.

42 Exhibit B-36, BCUC Supplementary IR1 3.3.2.

43 Exhibit B-36, BCUC Supplementary IR1 3.6.

44 Exhibit B-36, BCUC Supplementary IR1 1.4.

levels, even with mitigations in place, by 2026.[45] This underscores the urgent need for additional ITS pipeline capacity.

33. FEI was asked whether the methodology accounts for customer departures. It does. FEI used net customer additions in the base year of the forecast and applied the growth rates as described in Section 3.3.1.2 of the Updated Application to calculate the net customer additions in each year of the forecast period for residential, and small and large commercial customers. As a result, the growth in these customer classes, and therefore in peak demand produced by the method, is a net value and accounts for some customers leaving the system each year. The forecast method assumes that the proportion of customers added and removed from the system each forecast year remains the same as in the base year of the forecast. For large industrial customers, FEI does not forecast any account additions or reductions; rather, consistent with its long-standing practice, FEI assumes the industrial customer numbers, locations, and consumption patterns remain unchanged.[46]

(d) There Is No Basis to Discount the Forecast for Step Code and Other Policies

34. There is no basis to discount the forecast for the implementation of existing policies intended to encourage electrification or the BC Energy Step Code. First, these policies are already reflected in FEI's forecasting. The BC Energy Step Code measures implemented from 2019 to 2022 that may have impacted peak demand during the winters of 2018/2019, 2019/2020 and 2020/2021 are inherent in the data used to develop the 2022 peak demand forecast and thus have been taken into account.[47]

35. Second, FEI has not observed a quantifiable impact on customers' peak load in the area since the adoption of the BC Energy Step Code in large municipalities in the Okanagan area, including the cities of Kelowna, Penticton and Vernon.[48] This is consistent with what one would intuitively expect, as Step 3 was initially voluntary, and the portion of the overall existing building stock affected by the code is small. The influence will slowly grow over time as new construction

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45 Exhibit B-36, BCUC Supplementary IR1 1.3 and 1.4.

46 Exhibit B-14, BCUC IR2 44.2.

47 Exhibit B-18, CEC IR2 54.1 See also Exhibit B-2, BCUC IR1 5.7 and Exhibit B-4, CEC IR1 7.1 and 7.2.

48 Exhibit B-2, BCUC IR1 5.2.1. See also Exhibit B-36, BCUC Supplementary IR1 3.4 and 3.5.

and building retrofits that occur subsequent to the code coming into effect gradually make up a greater proportion of customers.

36. Third, it cannot be presumed that the impact of the Step Code is necessarily going to be to materially reduce the peak. The requirements of Step 3 of the BC Energy Step Code, which became a requirement across the Province on May 1, 2023, can be met with the installation of high efficiency gas equipment and building envelope solutions. Further, customers who implement greater than 100 percent efficiency electric heating equipment may choose to also install secondary gas heating equipment as a back-up system. Both cases will increase the overall peak demand on the system.[49]

37. As discussed above, the population of the Okanagan region has continued to increase, and this population growth has led to a corresponding increase in customer demand. Furthermore, increasing industrial load, including new CNG fuelling stations, greenhouse expansions and winery operations, along with other industrial customers on the system, has also contributed to the increase in demand. FEI noted that industrial customers are not impacted by the implementation of the BC Energy Step Code, as it is applicable only to new residential and commercial construction.[50]

38. FEI will be able to incorporate changes in energy use and impacts from policy changes as they occur into its planning processes because those changes are inherent in the data used to develop future peak demand forecasts and UPC values.[51] FEI refreshes its UPCpeak values for its customers each year based on the most recently available customer information. To the extent factors like the requirements of the BC Energy Step Code are influencing customer demand, they would be captured in the assessment of UPCpeak over time as building stock is replaced and improved.[52]

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[49] Exhibit B-36, BCUC Supplementary IR1 3.7.

[50] Exhibit B-2, BCUC IR1 5.7. See also Exhibit B-14, BCUC IR2 44.1 and 44.7.2.

[51] Exhibit B-36, BCUC Supplementary IR1 3.6.

[52] Exhibit B-36, BCUC Supplementary IR1 3.7.

39. The current peak demand forecasting methodology using typical account and customer growth rate forecasts is appropriate and prudent for system planning. This approach identifies potential constraints and solutions in advance of their need, and ensures only projects with a valid current need are implemented. Adjusting peak demand downwards as a result of uncertain impacts from policy or other pressures could ultimately result in a lower state of readiness and responsiveness to maintaining a robust and reliable transmission system.

(e) Recent Trends in Weather Are Accounted for in Peak Demand Forecast

40. FEI was asked whether recent trends in weather are accounted for in the peak demand forecast. They are reflected through work conducted in 2017.

41. FEI applies trends in recent weather history (that may reflect climate change impacts) by periodically re-adjusting the Design Degree Day ("DDD") temperature used to estimate peak demand. FEI last updated the DDD for each of the 22 weather zones in its operating territory in 2017. These updates examined the weather history in each weather zone over the preceding 60 years. The last update resulted in a slight warming in the DDD temperature in most weather zones. For example, in the case of the north and central Okanagan, the DDD changed from a 45.0 degree day to a 43.9 degree day. This represented a warming of 1.1°C in the design temperature. The Thompson region DDD warmed by 2.2°C and the South Okanagan warmed by 0.9°C. This results in lower peak demand estimates for customers in these regions than would have been calculated using the DDD values in use prior to 2017.[53]

42. FEI has not observed a correlation between colder than normal weather in a given year and the magnitude of the peak demand in that year. Extreme cold weather days which determine FEI's peak demand do not necessarily occur in colder than normal weather years. Short periods of extreme low temperatures can occur even in warmer than normal weather years.[54] The coldest days for the regions served by the ITS in recent years have been observed in the last two years.[55]

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53 Exhibit B-2, BCUC IR1 8.4. See also Exhibit B-14, BCUC IR2 43.1.

54 Exhibit B-8, BCOAPO IR1 2.3.

55 Exhibit B-36, BCUC Supplementary IR1 4.4.

E. CAPACITY SHORTFALL WILL HAVE SIGNIFICANT ADVERSE CONSEQUENCES

43. The evidence discussed below demonstrates that the pending capacity shortfall would have significant, and increasingly severe and broad, consequences for firm customers in the Okanagan region. It will also impact FEI's ability to serve new customers.

(a) Residential and Commercial Customers May Experience a Material Outage During Coldest Times of the Winter

44. The most severe consequence of a capacity shortfall is that FEI will be unable to serve Okanagan customers reliably during the winter season. As temperatures drop and heating load increases, load will exceed the design capacity limits of the system.[56] Population growth in the area will increase the severity of the capacity shortfall, placing more customers at risk of losing service even during lighter load periods. At the same time, the number of gate stations in the Okanagan experiencing insufficient pressure under peak demand will grow, which will put additional communities at risk.[57]

45. A capacity shortfall would predominantly impact residential, commercial (e.g., restaurants and shopping malls), and institutional customers (e.g., schools, hospitals, and community centres). 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. As a result, FEI must resort to curtailing a larger pool of smaller firm customers in order to reduce the peak load sufficiently to allow the system to function at all.[58] These customers could be without gas for heat, hot water, and cooking for an extended period (many days or weeks) during winter.[59] The impacts of a gas supply shortage under severe winter conditions (i.e., extreme low temperatures) can present very significant health and safety issues for customers.[60]

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[56] Exhibit B-1-2, Updated Application, p. 26.

[57] Exhibit B-1-2, Updated Application, p. 28.

[58] Exhibit B-1-2, Updated Application, p. 28.

[59] Exhibit B-1-2, Updated Application, p. 28.

[60] Exhibit B-16, BCOAPO IR2 7.1.

46. The first regions to experience a capacity shortfall, and require curtailments of firm customers to keep the system functioning to serve remaining customers, would be the communities of West Kelowna, Lavington, and Lumby – communities in which FEI currently has approximately 18,300 customers.[61] The systems in these communities are supplied by the Kelowna #1 Gate Station and the Polson Gate Station, which require inlet pressures sufficient to maintain an adequate pressure differential between transmission inlet pressure and discharge pressure. Due to their approximate midpoint location on the ITS mainline, the inlets of both stations experience the lowest pressures experienced on the ITS. Current forecasts indicate that the inlet pressures would be insufficient to operate the stations in the case of extreme cold conditions. Left unaddressed, the impact of insufficient system capacity would spread along the ITS from those major gate stations impacting other customers in nearby regions such as Greater Kelowna, Lake Country, Vernon, and Coldstream.[62]

(b) FEI May Need to Defer Attachments of New Customers in Certain Locations

47. FEI's evidence is that, if the OCU Project is not placed into service within its proposed timeline, FEI would likely be unable to connect any new gas customers to meet growth in the region (or expand service to existing customers).[63] Depending on the attachment location within the system and the load of the potential customer, FEI would have to consider deferring the attachment of new firm customers if the OCU Project (or an alternate project) was not built.[64]

F. ITS DELIVERY CAPACITY MUST BE INCREASED TO ALLOW FEI TO DELIVER THE SERVICE EXPECTED UNDER THE UCA

48. With respect to existing customers, the BCUC ultimately determines what quality of service, per section 38, that "the commission considers is in all respects adequate, safe, efficient, just and reasonable." The BCUC's determination in this CPCN Application will be, in effect, a determination on the quality of service that meets that legal standard. As discussed in this Final

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[61] Exhibit B-1-2, Updated Application: Customers served by the Kelowna #1 Intermediate Pressure system number approximately 16,300 in West Kelowna and the customers served by the Polson Intermediate Pressure system in Vernon number over 2,000 in Lavington and Lumby.

[62] Exhibit B-2, BCUC IR1 2.6.

[63] Exhibit B-36, BCUC Supplementary IR1 23.5.

[64] Exhibit B-42, BCSEA Supplementary IR1 31.11.

Submission, FEI's evidence is that the OCU Project is critical to avoid a circumstance where FEI is no longer able deliver the continuity of service that its firm customers in the Okanagan have come to expect. That is, unless the Project is approved, FEI would be forced to curtail firm (i.e., non-interruptible) customers on the coldest winter days in the Okanagan region when the system is experiencing its peak demand. The scale and frequency of the gas outages resulting from growing demand without an associated capacity upgrade would increase each year as demand grows.[65] FEI submits that the inability to reliably serve customers due to a shortage of capacity on the ITS during a cold weather event should be unacceptable. The BCUC should determine that an essential element of service that is "in all respects adequate, safe, efficient, just and reasonable" is being able to reliably serve the Okanagan peak load so that customers do not lose service in a cold winter.[66] Approving the Project is in the public interest by virtue of allowing FEI to continue providing the current level of service.

49. The BCUC's decision on the OCU Project also has implications for the duty to serve new customers under section 28 of the UCA, and FEI filed this Application in recognition of the importance of continuing to make service available to new customers in the Okanagan that want it.[67] The BCUC got to the heart of this issue in Order G-212-23,[68] when it asked FEI to reconcile its response to BCUC Supplementary IR1 23.5[69] that "if the OCU Project is not placed into service within its proposed timeline, FEI would likely be unable to connect any new gas customers to meet growth in the region" with section 28 of the UCA.

50. For reference, section 28 provides in part:

> (1) On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose.

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65 Exhibit B-20, PIB IR1 18.1.

66 Please also refer to the response to Exhibit B-20, PIB IR1 19.1 for a discussion of FEI's statutory obligation to serve customers.

67 Exhibit B-1-2, Updated Application, p. 29.

68 Exhibit A-36.

69 Exhibit B-36.

> …
>
> (3) After a hearing and for proper cause, the commission may relieve a public utility from the obligation to supply service under this Act on terms the commission considers proper and in the public interest.

51. Section 28 of the UCA is a strong justification for approving the Project because the Project avoids the imminent potential for FEI and the BCUC to be faced with making an undesirable choice between: (a) allowing a new customer to connect, or allowing an existing customer to increase load, at the expense of increasing the risk of a winter outage for existing customers, or (b) seeking/granting relief from FEI's obligation to provide service to the potential new customer/new load to avoid increasing the outage risk for existing customers. Allowing this situation to develop would be unprecedented in the case of FEI, and FEI submits that there is a sound public interest rationale in continuing to size facilities to meet forecast peak demand.

PART THREE: FEI HAS APPROPRIATELY ANALYZED THE ALTERNATIVES TO THE PROJECT

52. FEI identified the relevant alternatives to meet the need for the Project, analyzed and screened out alternatives that were not feasible, and further evaluated those that were feasible based on financial and non-financial criteria. The results of the analysis demonstrate that Alternative 3, the OLI PEN 406 extension, is the preferred solution with the lowest overall impact in terms of technical design, scope, complexity, cost, construction, environmental, archaeological and societal impacts.[70] FEI submits that its alternatives analysis was robust and that it correctly identified the OLI PEN 406 extension as the preferred alternative.

53. In the sections below, FEI addresses the key topics explored in IRs with respect to the alternatives analysis for the Project, making the following points:

(a) FEI followed a structured alternatives approach that identified a range of potential solutions for assessment against Project objectives;

(b) FEI identified all reasonable alternatives;

(c) FEI appropriately screened out two infeasible options; and

(d) FEI's evaluation framework was subject to rigorous internal review and properly weighted relevant considerations reflecting the Project's objectives.

A. FEI FOLLOWED A STRUCTURED APPROACH

54. The need to address a future capacity shortfall in the Okanagan area was previously identified in FEI's 2017 LTGRP ("Long Term Gas Resource Plan") filing.[71] Since then, FEI has considered and examined options to address the need for the OCU Project. FEI identified and investigated five alternatives, including four pipeline installation options and a Liquefied Natural Gas ("LNG") storage/peak shaving option:[72]

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70 Exhibit B-1-2, Updated Application, pp. 56-57; Exhibit B-4, CEC IR1 2.2.1.

71 As discussed in Section 3.4 of the Exhibit B-1-2, Updated Application.

72 Exhibit B-1-2, Updated Application, pp. 32-33 and Section 4.3.

Alternative	Description
Alternative 1 – ITS Upgrades to VER PEN 323	Upgrades along approximately 36 km of the Vernon to Penticton 323 mm pipeline (VER PEN 323) in the form of pipeline replacement and revalidation hydrotests. This alternative is further described in Section 4.2.1 of the Updated Application.
Alternative 2 - Modified ITS Upgrades to VER PEN 323	Modifications 1 to the VER PEN 323 pipeline similar to Alternative 1. However, this alternative involves the installation of a 6 km extension of the 406 mm OLI PEN pipeline around the City of Penticton. The 6 km long extension proposed under this alternative eliminates the requirement to replace and/or retest multiple segments from the southern end of Alternative 1, and replaces them with a pipeline extension. This alternative is further described in Section 4.2.2 of the Updated Application.
Alternative 3 - OLI PEN 406 Extension	Addition of approximately 30 km of 406 mm pipeline running from OLI PEN 406 pipeline east of Ellis Creek near Penticton to Chute Lake northeast of Naramata. This alternative is further described in Section 4.2.3 of the Updated Application.
Alternative 4 – 508 mm North Loop from Savona	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. This alternative is further described in Section 4.3.4 of the Updated Application.
Alternative 5 – LNG Peaking Plant near Vernon	An LNG storage and peak shaving facility located between Westwold and Grandview Flats northwest of Vernon. 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. This alternative is further described in Section 4.3.5 of the Updated Application.

55. FEI conducted its evaluation of these alternatives in two steps. First, FEI established the technical feasibility of each alternative. This included assessing which alternatives met FEI's technical requirements to sufficiently address low system pressures in the affected region prior to the forecast capacity shortfall. At this first stage, FEI concluded that Alternatives 4 and 5 did not meet the primary Project objectives and were not feasible to implement within the timeframe required to meet capacity requirements.

56. At the second stage, FEI developed a weighted scoring methodology and applied it to each of the three feasible alternatives (Alternatives 1 through 3) to determine their performance in relation to the evaluation criteria defined for the Project. The evaluation criteria were grouped into three primary categories:[73]

[73] Exhibit B-1-2, Updated Application, p. 46.

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

57. Evaluation criteria and weightings for any project are selected based on the individual and unique requirements of a specific project.[74] FEI conducted a workshop of internal subject matter experts to determine a set of evaluation criteria and associated weightings appropriate for the OCU Project requirements. The Project team then refined the criteria and weightings as the Project progressed and the Project team's understanding of the specific needs of the Project improved.[75]

58. FEI's team members have extensive experience on multiple projects, including the Inland Gas Upgrades ("IGU"), Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU"), Coastal Transmission System Upgrade ("CTS"), Eagle Mountain to Woodfibre Gas Pipeline ("EGP"), and various sustainment capital projects throughout the Province. The experiences from these projects contribute to FEI's management of potential knowledge gaps and bias during the evaluation criteria, weighting, and evaluation stages. Moreover, FEI retained various subject matter consultants to provide the necessary input for the evaluation.[76]

B. FEI IDENTIFIED ALL REASONABLE ALTERNATIVES

59. The five alternatives that FEI identified and assessed represent all of the alternatives that ought to have been assessed in the process. Some concepts that were explored by proceeding participants in IRs were not reasonable options that required in-depth evaluation.

60. The evidence supports FEI's decision to not consider adding additional compressor facilities within the Savona to Penticton corridor. FEI determined a compressor alternative to be operationally infeasible due to the high variability in system load over the peak day period on the system and due to the system being broken into several different segments with different

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[74] Exhibit B-9, BCSEA IR1 13.1.

[75] Exhibit B-2, BCUC IR1 22.5 and 22.6.

[76] Exhibit B-23, PIB IR3 10.5.1a.

minimum operating pressure constraints. The compressors also do not provide operational benefits outside of peak days in winter. Finally, a compressor alternative would be difficult to expand to address future load growth beyond the forecast period.[77]

61. FEI was similarly justified in not considering constructing a new pipeline in two locations, due to the increases to the complexity of the environmental, archaeological, Indigenous, and public impacts. By analyzing the proposed pipeline locations separately, FEI was able to determine which alternative represents a more efficient and effective method of increasing gas flow to the major load centres in the Okanagan. The OLI PEN 406 extension (Alternative 3) can provide adequate capacity while only requiring half the total pipeline length as compared to a pipeline extension constructed from the Savona Compressor Station. In contrast, constructing in two locations would be more expensive, more difficult from a logistics and scheduling perspective, and would have greater impact on Indigenous groups and communities, with no incremental benefits.[78]

62. FEI considered alternatives to address the forecast capacity shortfall at a local level in the communities of West Kelowna, Lavington, and Lumby such as CNG/LNG supply augmentation and customer load curtailment, but correctly rejected them:

- These alternatives are not viable long-term solutions for the ITS and do not provide the reliability, resiliency, and operational benefits to the ITS outside of these local areas. The proposed OCU Project will not only provide a capacity enhancement that is available year-round to support peak demand, but it will also enhance the way the system can be configured in lower demand periods to support operations and maintenance work on the ITS within the Thompson and Okanagan region.[79] As demand on the ITS increases, the magnitude of the capacity

[77] Exhibit B-2, BCUC IR1 15.1.

[78] Exhibit B-14, BCUC IR2 51.4.

[79] Exhibit B-2, BCUC IR1 2.6.1.

shortfall will increase and, along with it, the number of customers affected in the case of a shortfall will rise.[80]

- While addressing the capacity deficit on the ITS at a local level could have some short-term benefits, over the long-term it is not considered a feasible solution for the OCU Project. Addressing the deficit by installing local supply would ultimately require multiple facilities to be operated and maintained, and each would be significantly larger in scale than the initial needs to meet escalating future requirements. Any operational benefits would be more localized and less useful to support operations work on the system elsewhere. Addressing the issue by curtailing local customer demand would provide no operational benefit to the ITS, and there is no means in the gas distribution system to apply targeted curtailment to the local customers.[81]

- Finally, this approach would place the burden of insufficient system capacity on a group of FEI customers who would be disadvantaged simply because of the community in which they are located. [82]

C. FEI APPROPRIATELY SCREENED OUT TWO INFEASIBLE OPTIONS

63. FEI's decision to screen out Alternative 4: 508 mm North Loop from Savona and Alternative 5: LNG Peak Shaving Facility near Vernon was reasonable for the following reasons:

- Neither option could be completed in time to address forecast capacity shortfalls. Alternative 4, for instance, would require an environmental assessment, which is expected to add a minimum of three years to the Project schedule as well as schedule uncertainty. As a result of the lengthier timelines, Alternatives 4 and 5 did not meet the primary objectives of the Project. [83]

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80 Exhibit B-2, BCUC IR1 2.6.1.

81 Exhibit B-9, BCSEA IR1 2.4.

82 Exhibit B-2, BCUC IR1 2.6.1.

83 Exhibit B-1-2, Updated Application, p. 46.

- Preliminary high level cost estimates indicated that both Alternative 4 and Alternative 5 would be significantly more costly as compared to other alternatives considered for the Project.[84]

- Alternative 4 required almost a doubling of installed pipeline length without providing any additional capacity benefit as compared to the preferred Alternative 3.[85]

- 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.[86]

64. All of these factors remain applicable under the Supplementary Filing Forecast.[87]

D. ALTERNATIVE 3 EMERGED AS SUPERIOR TO OTHER ALTERNATIVES

65. FEI's analysis based on the evaluation criteria indicates that Alternative 3 is the superior alternative.

66. Table 4-9 of the Updated Application, reproduced below, provides a summary of FEI's assessment of Alternatives 1, 2, and 3 against all evaluation criteria. Alternative 3 has the highest total weighted score at 3.60 out of 5 points.

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84 Exhibit B-1-2, Updated Application, p. 46; Exhibit B-4, CEC IR1 11.1. 11.2, 12.1 and 12.2; Exhibit B-2, BCUC IR1 21.2.

85 Exhibit B-4, CEC IR1 10.1.

86 Exhibit B-4, CEC IR1 10.2 and 10.4.

87 Exhibit B-36, BCUC Supplementary IR1 11.1.2.

Updated Application Table 4-9: Overall Alternative Evaluation

Criterion	Weighting	Alternative 1: ITS Upgrades Weighted Score	Alternative 2: Modified ITS Upgrades Weighted Score	Alternative 3: OLI PEN 406 Extension Weighted Score
Asset Management Capability	40%	3.5	4.0	4.5
Project Execution and Lifecycle Operation	30%	1.45	1.45	3
Financial / Rate Impact	30%	4	2	3
Weighted Total:*	**100%**	**3.04**	**2.64**	**3.60**

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

67. Alternative 3 scored the highest against the technical (non-financial) criteria. This was primarily due to significant schedule risks associated with Alternatives 1 and 2, as well as the significant impact to the public associated with re-hydrotesting in urban areas. Alternative 3 also provided the greatest positive impact to operational flexibility.[88]

68. The financial evaluation of the three feasible alternatives indicated minimal differences in rate impacts between all three alternatives. Alternative 2 had the highest incremental cost for ratepayers as a result of its higher cost and resulting higher levelized rate impact. However, there was a relatively small difference in the rate impact between Alternative 1 and Alternative 3.[89]

69. Alternative 3 remains the superior alternative after accounting for new information regarding delays in the construction start and the updated Supplementary Filing Forecast:

- The delays in construction start would apply equally to the other two feasible alternatives and as such, the relative weightings assigned to each alternative would remain unchanged.

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88 Exhibit B-1-2, Updated Application, p. 56. See also Exhibit B-2, BCUC IR1 22 series and Exhibit B-6, RCIG IR1 15.1.

89 Exhibit B-1-2, Updated Application, p. 57.

- The changes in costs to the proposed OCU Project are proportionately applicable to the other alternatives.[90]

- The key reasons for the selection of the preferred alternative are not impacted by the reduction in forecasted peak demand between the Updated Application and the Supplementary Filing Forecast; therefore, the scoring of each alternative would not change materially.[91]

70. Given the immediate need for the OCU Project and the schedule risks associated with the other two feasible alternatives, the proposed alternative remains superior.[92]

[90] Exhibit B-41, BCOAPO Supplementary IR1 4.7. See also Exhibit B-40, RCIA Supplementary IR1 50.2 and 50.3.

[91] Exhibit B-36, BCUC Supplementary IR1 11.1.1 and 11.1.2.

[92] Exhibit B-41, BCOAPO Supplementary IR1 4.7.

PART FOUR: PROJECT DESCRIPTION AND COST ESTIMATE

71. FEI's Application describes the proposed Project, including project components, final route evaluation and selection process, basis of design and engineering, construction, project schedule and resourcing requirements, qualitative risk assessment and analysis and contingency estimate, cost estimate, and accounting treatment.

72. Appendices A to E of the Updated Application provide the supporting FEED Reports, Cost Estimates, Risk Analysis reports, Project Schedule, and Financial Schedules. FEI has updated information, where appropriate, in the Supplementary Filing. The cost estimate for the OCU Project is $327.410 million in as-spent dollars, including contingency and allowance for funds used during construction ("AFUDC").[93]

73. The Project will result in an estimated delivery rate impact of 2.37 percent by 2027 when all assets as well as closing costs have entered rate base. This is equivalent to approximately $0.125 per GJ when compared to FEI's 2023 approved delivery rates. For an average FEI residential customer consuming 90 GJ per year, this would equate to a total bill impact of approximately $11.22 in 2027.[94]

74. The evidence demonstrates, and the BCUC should find, that the Project is well-defined. The cost estimates are reasonable. FEI has appropriately considered project risks, and incorporated those risks into the contingency for the Project. FEI has processes in place to manage risks throughout the life of the Project.

75. In the subsections below, FEI addresses the key topics explored in the IRs related to the Project description and cost estimate. FEI makes the following points:

(a) The Project, including the pipeline size and length, remains appropriate in light of the Supplementary Filing Forecast;

(b) FEI has appropriately evaluated and selected a route for the Project;

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[93] Exhibit B-35, Supplementary Filing, Table 3-1, p. 9.

[94] Exhibit B-35, Supplementary Filing, pp. 15-16.

(c) The planned deactivation of a 1,200 m section of the existing OLI PEN 406 between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station is more cost-effective than abandonment, minimizes disturbances and provides resiliency benefits for customers;

(d) The Project schedule has been updated to address need;

(e) FEI has given proper consideration to the Penticton Creek crossing;

(f) FEI has accounted for required permits and approvals;

(g) FEI's cost estimate is credible and will continue to be refined; and

(h) FEI will continue to identify and manage risk over the life of the Project.

A. PROJECT IS APPROPRIATELY SCOPED

76. FEI has appropriately scoped the Project, including the pipeline size and length.

(a) Overview of Project Scope

77. The Project scope will include the routing, design, construction and commissioning of a new 30 km section of 406 mm pipeline and associated facilities. The main Project components include:[95]

- The construction and installation of approximately 30 km of new 406 mm pipeline that will operate at a Maximum Operating Pressure ("MOP") of 7,826 kPa at kilometre point 30.8;

- The construction and installation of a new Chute Lake Pressure Control Station at kilometre point 60.8. It will include a 406 mm pig barrel and pressure regulated tie-in to the existing VER PEN 323 pipeline set at 5,171 kPa for gas flowing north to Kelowna and 4,826 kPa for gas flowing south to Penticton;

- The construction and installation of a new above ground 406 mm Block Valve Station at kilometre point 36.1; and

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[95] Exhibit B-1-2, Updated Application, pp. 58-59; Exhibit B-9, BCSEA IR1 15.1.

- A 1,200 m section of the existing OLI PEN 406 will be deactivated between the tie-in location at kilometre point 30.8 and the Ellis Creek Pressure Control Station.

78. The objective of the proposed pipeline is to overcome the capacity restriction in the VER PEN 323 pipeline between Penticton and Kelowna by moving the pressure control station (currently at Ellis Creek in Penticton) supplying gas into the pipeline far enough north to provide the required capacity.[96]

79. Based on 30 percent completion of the design and route alignment, the length of the OLI PEN 406 Extension is 30,370 metres.[97] This length may change slightly depending on any route adjustments that may occur during detailed design.[98]

80. The pipe size needs to be large enough to deliver gas from the OLI PEN 406 while retaining sufficient pressure at the end point to deliver gas into the VER PEN 323 pipeline, with additional pressure available to allow it to be extended in the future if required. FEI's assessment is that an NPS 16 extension to the South Okanagan Natural Gas pipeline could provide sufficient capacity to meet the current project need and allow a future extension north if needed to meet future load. The selection of the NPS 16 pipe provides benefits and results in a lower cost than the NPS 20 pipe that was considered by FEI in early developments stages. An NPS 16 pipeline also improves the efficiency of pipeline integrity activities as the pipeline will form a continuous run of NPS 16 pipeline between Oliver and the new Chute Lake Station that can be inspected in a single uninterrupted in-line inspection (ILI) run.[99]

(b) Original Scope Remains Appropriate in Light of Supplementary Filing Forecast

81. The original scope of Alternative 3 remains appropriate in light of the Supplementary Filing Forecast. The impact of the Supplementary Filing Forecast was relatively minor in

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[96] Exhibit B-2, BCUC IR1 18.1.

[97] Exhibit B-20, PIB IR1 17.1.

[98] Exhibit B-20, PIB IR1 21.3.

[99] Exhibit B-2, BCUC IR1 18.1. See also BCOAPO Supplementary IR1 4.5.

comparison to the overall Project, allowing FEI to potentially reduce the length of the pipeline scope from roughly 30 km to roughly 26 km.[100]

82. FEI estimates a potential savings of approximately $25.6 million by reducing the required pipeline length by 4 km. Based on this approach, the Chute Lake Control Station would be relocated approximately 4 km upstream of the proposed site.[101]

83. While reducing the pipeline length by 4 km is feasible, the original Project scope remains superior. If the OCU Project is shortened by 4 km, there will be a change in Project cost of approximately 7.8 percent; however, the corresponding change in incremental capacity is a decrease of 26 percent, indicating that the decrease in Project cost is more than offset by the reduction in benefits gained from the incremental capacity.[102]

84. In addition, there will continue to be year-to-year variability in the peak demand forecasts, and the next year's peak demand forecast could be closer to the Updated Application Forecast.[103] FEI expects that future forecasts for the ITS will be higher than the Supplementary Filing Forecast for two reasons:[104]

- The latest Conference Board of Canada housing starts forecast for single and multi-family dwellings which will be used in development of the 2023 Peak Demand Forecast is much more robust than that which was used to develop the 2022 Peak Demand Forecast. That, coupled with the 2022 customer additions for RS 1 being approximately 22 percent higher than 2021, which is the seed value for the forecast growth, is expected to drive a higher forecast growth in RS 1 peak demand. RS 1 contributes approximately 50 percent of the total peak demand.

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[100] Exhibit B-36, BCUC Supplementary IR1 11.1.1 and 13.2.

[101] Exhibit B-36, BCUC Supplementary IR1 13.2. Please refer to the response to BCUC Supplementary IR1 13.2.2 for all other assumptions related to the cost savings calculation.

[102] Exhibit B-36, BCUC Supplementary IR1 13.2.

[103] Exhibit B-36, BCUC Supplementary IR1 13.2, and as described in the response to BCUC Supplementary IR1 1.3, This possibility is borne out in the peak demand forecast curve provided in response to BCUC Supplementary IR1 1.8 (i.e., the green curve).

[104] Exhibit B-36, BCUC Supplementary IR1 13.2.

- The 2022 UPCpeak values increased relative to 2021.[105] Since a three-year rolling average of UPCpeak is used, this will put directionally upward pressure on the UPCpeak values used in the development of the 2023 Peak Demand Forecast. To the extent the 2023 UPCpeak values are higher yet, it will further contribute to higher peak demand.

B. FEI HAS APPROPRIATELY EVALUATED AND SELECTED A ROUTE FOR THE PROJECT

85. The evidence establishes that FEI's route evaluation and selection process is reasonable.

(a) Route Selection Process Consistent with Industry Practice, Past Applications and CSA Standards

86. FEI's route selection process for the OCU Project follows industry practice, and is consistent with the process FEI has used in past project applications. It reflects Canadian Standards Association standard CSA Z662:19 Oil & Gas Pipeline Systems, which is the standard specification for the design, construction, operation, and maintenance of Canadian pipelines.[106]

87. Pipeline routing is an iterative process which starts with a wide "corridor of interest" and then narrows down to a more defined route at each design stage as more data is acquired, resulting in a final alignment. The process has been tailored to meet the challenges associated with development, land use, terrain, watercourses, infrastructure, local permits and regulations, the environment, archaeology as well as impacts to Indigenous groups, communities and stakeholders. Based on these considerations, FEI determined that the final route selected must meet the following objectives: [107]

- Safe (to construct and to operate);
- Minimize impacts to Indigenous groups, the community, and stakeholders;
- Minimize environmental impacts;

[105] As shown in the response to Exhibit B-36, BCUC Supplementary IR1 3.3.

[106] Exhibit B-1-2, Updated Application, p. 59.

[107] Exhibit B-1-2, Updated Application, p. 59.

- Maximize the use of modern standard pipeline construction techniques; and

- Mitigate rate impacts to customers.

88. FEI applied and evaluated the routing objectives, including the two-step route selection process which includes an assessment of the feasible options to determine the final route.[108]

89. Three broad categories of principles and considerations which were taken into account during the route options evaluation to address the route objectives: Community and Stakeholder Criteria, Environmental Criteria, and Technical Criteria.[109] The evaluation criteria definitions used for the OCU Project are consistent with those of two recent FEI CPCN applications to the BCUC: the Pattullo Gas Line Replacement ("PGR") Project, and the LMIPSU Project. FEI has made minor adjustments to several technical criteria for the OCU Project due to the unique project requirements and site-specific conditions.[110]

90. The Pipeline Route Evaluation Weighting factors used for the OCU Project are also similar to previous FEI applications to the BCUC. Weightings vary between projects based on unique project requirements and site-specific conditions. For example, the PGR Project was constructed in an urban environment within city road allowances, as compared to the OCU Project's construction in more rural and rugged terrain within rights-of-way.[111]

91. After determining the segment alignments relative to existing infrastructure, further route optimization was conducted to review the alignment for constructability and analyze route deviations for natural features or man-made obstructions, and based on stakeholder feedback. Figure 5-3 of the Application, reproduced below, presents the preferred route in relation to the

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[108] Exhibit B-1-2, Updated Application, p. 59. More details on FEI's route selection process are contained in the Pipeline Routing Criteria and Evaluation Report, P-00760-PIP-REP-0005, included in Appendix A-1 of the Updated Application.

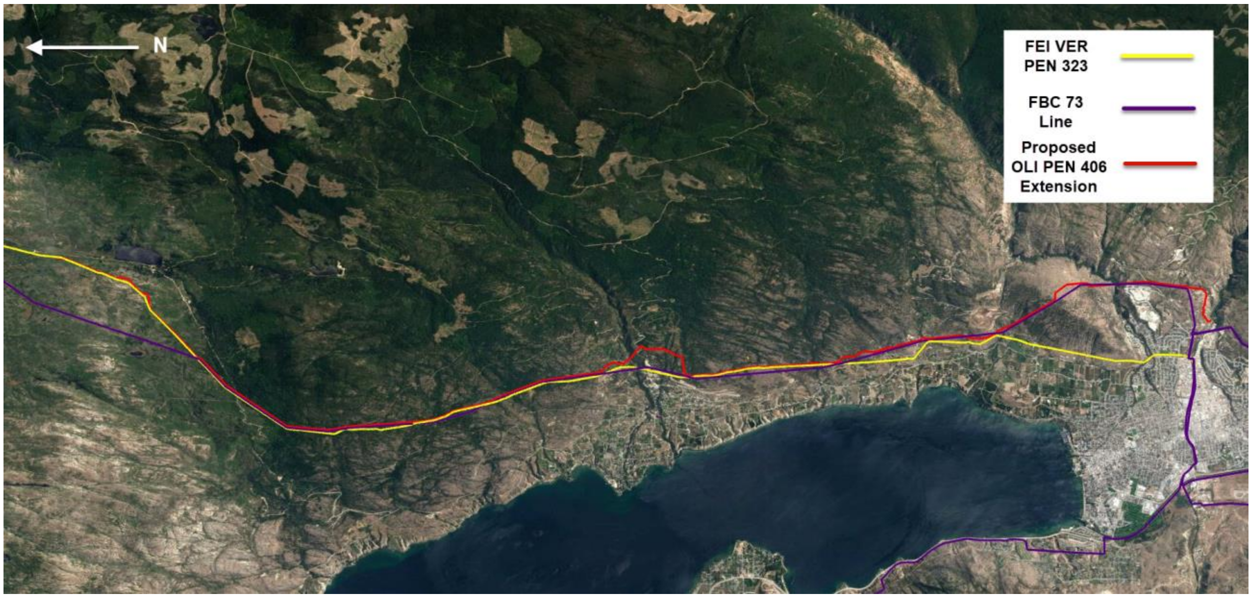
[109] Exhibit B-1-2, Updated Application, p. 61.

[110] Exhibit B-9, BCSEA IR1 16.3.

[111] Exhibit B-9, BCSEA IR1 16.4.

VER PEN 323 and FortisBC Inc. 73 Line alignments.[112] The identified corridor accounts for natural terrain features as well as current and planned infrastructure creating the varied widths.[113]

Updated Application Figure 5-3: Preferred OLI PEN 406 Extension Alignment



92. The 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.[114] Minor adjustments to the route alignment can still occur to accommodate new information.[115]

93. The final routing for the pipeline 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

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[112] Exhibit B-1-2, Updated Application, p. 65; Project alignment sheets of the preferred route are provided in drawings 12264-P-200-1000-R0 to 12264-P-200-1039-R0, in Appendix A-1. Details of the scoring of each evaluation criterion for all options are provided in the Route Selection Report, P-00760-PIP-REP-0009, included in Appendix A-1.

[113] Exhibit B-9, BCSEA IR1 16.2.

[114] Exhibit B-1-2, Updated Application, p. 67.

[115] Exhibit B-4, CEC IR1 23.1.

applied throughout construction to minimize the potential spread or introduction of invasive plants. Some vegetation removal will be required during site preparation and construction.[116]

94. It is unlikely the final route will differ from the proposed alignment provided in the Class 3 estimate. Any deviations will be the result of technical or construction challenges determined during detailed engineering design or from continued stakeholder and landowner consultation.[117]

(b) Financial Considerations Are Implicitly Reflected in the Routing Criteria

95. FEI was asked why there is no explicit financial criterion. Adding explicit financial criteria would result in double-counting of cost. FEI's routing criteria already implicitly reflected financial considerations because the assessment incorporated all routing factors that typically drive project costs.

96. Impacts on cost are inherent in any challenges associated with a specific criterion. Through the scoring process, any negative impact would naturally increase the Project's cost or delay its schedule, or both. For example, more complex construction practices increase costs. 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.[118]

97. As the routing process considers multiple variations, using this implicit cost methodology is the most effective way to ensure cost-effective routing. A route selection that minimizes impacts to all criteria without adding extensive length or scope would result in selection of the lowest cost solution.[119]

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[116] Exhibit B-1-2, Updated Application, p. 83.

[117] Exhibit B-20, PIB IR1 21.3. Exhibit B-40, RCIA Supplementary IR1 52.1 provides a confidential response regarding the potential for changes in pipeline alignment as a result of FEI's consultations with the PIB.

[118] Exhibit B-4, CEC IR1 22.3.

[119] Exhibit B-18, CEC IR2 60.1.

98. The preferred route minimizes the impacts to all evaluation criteria for the OCU Project without adding extensive length. As such, FEI considers the OCU Project to be the most cost-effective overall solution.

C. DEACTIVATION OF 1,200 METRE PIPELINE SECTION PROVIDES BENEFITS AND IS MOST COST-EFFECTIVE

99. As part of the Project, a 1,200 m section of the existing OLI PEN 406 will be deactivated between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station.[120] Deactivation will follow all regulatory and code requirements.[121] This will include removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line and maintaining a low pressure blanket with nitrogen.[122] The Ellis Creek Station will be deactivated in a similar fashion to the OLI PEN 406 pipeline section with the ability for future reactivation.[123]

100. Deactivation has a number of important advantages over abandonment:

- Deactivation minimizes ecological and socio-economic disturbance to the area. The abandonment process for the section of the existing OLI PEN 406 would have the potential to disturb contaminated soils in and around the industrial parks located along Okanagan Avenue, potential archaeological sites, and disturbance to sensitive creek crossings.[124]

- Abandonment, unlike deactivation, would negatively impact some local businesses. The OLI PEN 406 traverses several industrial parks and the excavation work required to support the abandonment process could impede their operations.[125]

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[120] Exhibit B-1-2, Updated Application, p. 74.

[121] Exhibit B-1-2, Updated Application p. 74.

[122] Exhibit B-1-2, Updated Application p. 74. See also Exhibit B-14, BCUC IR2 56.1 and 56.2.

[123] Exhibit B-6, RCIA IR1 21.1; Exhibit B-14, BCUC IR2 56.3.1.

[124] Exhibit B-2, BCUC IR1 30.3.

[125] Exhibit B-2, BCUC IR1 30.3.

- The scope of work for deactivation is simpler than abandonment. Deactivation consists of removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line, and maintaining a low pressure blanket with nitrogen.[126]

- By virtue of being simpler, deactivation of the section of pipe is less costly than abandonment. Deactivation is expected to cost approximately $86,000,[127] whereas abandonment would be approximately $221,000.[128] Annual ongoing maintenance costs of the deactivated section are only approximately $3,800 per year.[129]

- Deactivation, unlike abandonment, allows re-establishment of gas supply to the Ellis Creek Pressure Control Station if required in the future to support forecast peak demand.[130]

- FEI requires the ability to reactivate this section of the OLI PEN 406 for the potential of future integrity management activities which would then require the use of the Ellis Creek Station.[131]

101. The deactivated pipeline continues to provide a benefit to customers. FEI requires the ability to reactivate this pipeline section as part of future integrity management activities. The value to FEI of the right-of-way and pipeline is significant as it provides flexibility for integrity management activities for no incremental cost.[132]

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[126] Exhibit B-2, BCUC IR1 30.3 and 30.4; Exhibit B-36, BCUC Supplementary IR1 15.3.

[127] Exhibit B-2, BCUC IR1 30.4; Exhibit B-36, BCUC Supplementary IR1 15.3.

[128] Exhibit B-2, BCUC IR1 30.4; Exhibit B-36, BCUC Supplementary IR1 15.3. See also Exhibit B-14, BCUC IR2 56.11.

[129] Exhibit B-2, BCUC IR1 30.3; Exhibit B-36, BCUC Supplementary IR1 15.3.

[130] Exhibit B-1-2, Updated Application p. 74.

[131] Exhibit B-2, BCUC IR1 30.1.

[132] Exhibit B-2, BCUC IR1 30.5.

102. Annual ongoing maintenance costs of the deactivated section are only approximately \$3,800 per year. [133] This segment of pipe would be managed under applicable FEI standards and guidelines, including right-of-way patrol and inspections, vegetation management, third-party driven inspections, nitrogen blanket pressure inspection and calibration, and cathodic protection testing and maintenance.[134]

103. As described in detail in the response to BCUC IR2 56.4.2:[135]

- The 1.2 km section of the pipeline is used and useful now and will continue to be used and useful even after the proposed deactivation;
- The proposed deactivation of the 1.2 km section of the pipeline is the least cost option when compared to the alternatives of either continuing active service through the pipeline or abandonment; and
- The costs incurred by FEI for constructing the pipeline and acquiring the right of way in the mid 1990s were prudently incurred. In all of the alternatives, FEI's approved regulatory treatment for the remaining net book value of the 1.2 km section of the pipeline results in it continuing to remain in rate base.

104. In summary, the cost to deactivate the 1,200 m section of the OLI PEN 406 pipeline and reactivate it when required is the least cost option when compared against keeping the pipeline in active service or building a new line as well as other emergency measures in the event of a failure on the OLI PEN 406 Extension or the VER PEN 323 lines. This 1,200 m section of the pipeline will continue to be used and useful for service to customers by providing redundancy and preserving the ROW. FEI's approved regulatory treatment is to have these assets continue in rate base to ensure the recovery of the prudently incurred costs, regardless of the option.[136]

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133 Exhibit B-2, BCUC IR1 30.3; Exhibit B-36, BCUC Supplementary IR1 15.3.

134 Exhibit B-2, BCUC IR1 30.3; Exhibit B-36, BCUC Supplementary IR1 15.3.

135 Exhibit B-14.

136 Exhibit B-14, BCUC IR2 56.4.2.

D. PROJECT SCHEDULE DESIGNED TO ADDRESS PROJECT NEED

105. FEI updated the preliminary OCU Project execution schedule to reflect the delay experienced to date (see Table 3-2 of the Supplementary Filing).[137] The schedule is based on receiving CPCN approval by December 2023 and an assumed construction start of Q1 2025.

106. By using the same construction methodology to reduce the risks associated with working during forest fire season, bird nesting windows and other seasonal constraints, the revised schedule is generally deferred three years from what was outlined in the Updated Application.[138]

107. The OCU Project schedule estimates that Mainline Construction will be complete in July 2026, with restoration and demobilization occurring by October 2026. The OCU Project is therefore planned to be in service prior to October 2026 in order to address the capacity constraints.[139]

108. Although it may be technically feasible to complete the Project in two separate parts (i.e., southern portion completed initially and northern portion later), it would not meet FEI's Project objectives to maintain long-term safe, reliable, and cost-effective service to its customers based on forecast peak demand.[140] Completing the OCU pipeline in two separate parts would result in significant duplicated effort and additional costs. Based on costs to date incurred on the Project, FEI estimates that the duplicated effort would result in an additional $20 to $30 million of capital costs. Completing the Project as proposed in the Application eliminates the need for construction in parts and the additional costs associated with that approach.[141]

109. A two-part approach would necessitate duplicating consultation activities with Indigenous groups and stakeholders. Consulting with these groups twice for essentially the same project, would unnecessarily burden the Indigenous groups and stakeholders and involve considerable additional workload. In addition, FEI believes that the additional interconnect

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137 Exhibit B-35, Supplementary Filing, p. 10.

138 Exhibit B-35, Supplementary Filing, p. 10.

139 Exhibit B-38, CEC Supplementary IR1 8.2.

140 Exhibit B-14, BCUC IR2 50.2.

141 Exhibit B-22, BCUC IR3 68.1.

location into the VER PEN 323 would create unnecessary ground disturbance which would be more impactful to Indigenous groups and stakeholders.[142]

E. FEI HAS GIVEN PROPER CONSIDERATION TO THE PENTICTON CREEK CROSSING

110. During the development phase of the Project, FEI engaged an engineering firm specializing in horizontal directional drilling ("HDD") design and a contracting company specializing in constructing HDD crossings, to complete a preliminary design under Penticton Creek and to determine the feasibility of constructing the HDD.[143] While FEI indicated in the Updated Application that HDD is the preferred option across Penticton Creek, that may change during detailed design. If the open trench option proves more feasible than the HDD during detailed design, FEI may proceed with an open trench cut as the preferred option, with the HDD as the contingency plan.[144]

111. FEI is seeking approval of a CPCN to construct and operate the OCU Project based on either the HDD crossing or the open trench method. Given that a crossing of Penticton Creek is required to complete the Project, FEI will proceed with the crossing method that provides the least amount of risk to the Project, and which otherwise best accomplishes the Project goals. Further, the remainder of the route (which represents approximately 95 percent of the new pipeline construction) is well defined and established in the Updated Application.[145]

112. In the event that a material change to the proposed route alignment, outside the bounds of the Penticton Creek crossing, is necessary (i.e., a portion of the pipeline cannot be constructed in the approved corridor), FEI will file an application for approval from the BCUC to modify the route at least 90 days before construction is proposed to commence. [146]

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142 Exhibit B-22, BCUC IR3 68.3.

143 Exhibit B-14, BCUC IR2 54.1.

144 Exhibit B-2, BCUC IR1 26.1 and 26.4. See also Exhibit B-8, BCOAPO IR1 4.1 and Exhibit B-20, PIB IR1 42.1. PIB IR1 Attachment 42.2 outlines the geotechnical path and conceptual design plan for the Penticton Creek HDD alignment.

145 Exhibit B-14, BCUC IR2 54.1.

146 Exhibit B-14, BCUC IR2 54.1. See also Exhibit B-20, PIB IR1 21.3 and Exhibit B-14, BCUC IR3 67.1.

F. FEI HAS IDENTIFIED, AND ACCOUNTED FOR, REQUIRED PERMITS AND APPROVALS

113. FEI requires the following approvals prior to undertaking the OCU Project:[147]

- a CPCN from the BCUC;
- various approvals from the British Columbia Energy Regulator (the "BCER"); and
- finalized agreements with the City of Penticton and the Regional District Okanagan Similkameen (the "RDOS").

114. The Project will not require an Environmental Assessment Certificate under the BC *Environmental Assessment Act*.[148] The total length of the preferred alternative is only 30 km, and approximately 80 percent parallels existing linear corridors such as existing electric and gas rights of way and roads.[149]

115. FEI has sufficient time to obtain the various approvals required from the BCER and to finalize the agreements with the City of Penticton and the RDOS, and does not expect obtaining these approvals/agreements to delay the OCU Project schedule. A delay in obtaining an agreement with Indigenous communities or receiving CPCN approval from the BCUC by the dates outlined in Table 3-2 of the Supplementary Filing will directly impact the OCU Project schedule.[150]

116. Throughout the detailed design and construction phase of the OCU Project, FEI will also require various permits to execute the work. A description and the timing of these permits was provided in Sections 5.6 and 5.9 of the Application. FEI does not anticipate delays to the OCU Project schedule as a result of obtaining these permits, and FEI has made allowances within the schedule to account for minor delays if any should occur.[151]

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[147] Exhibit B-41, BCOAPO Supplementary IR1 9.1.

[148] Exhibit B-1-2, Updated Application, p. 85.

[149] Exhibit B-2, BCUC IR1 28.1.

[150] Exhibit B-41, BCOAPO Supplementary IR1 9.1. See also Exhibit B-37, BCUC Supplementary IR1 19.4.

[151] Exhibit B-41, BCOAPO Supplementary IR1 9.1.

G. THE COST ESTIMATE IS CREDIBLE AND WILL CONTINUE TO BE REFINED

117. The evidence demonstrates, and the BCUC should find, that the cost estimate is reasonable. As discussed below, FEI's cost estimate meets the requirements in the BCUC's CPCN Guidelines (AACE Class 3) and has been recently updated.

(a) The AACE Class 3 Estimate Meets CPCN Guidelines

118. FEI retained an Engineering Consultant, Solaris Management Consultants Inc. ("SMCI") to complete an AACE Class 3 cost estimate for the construction component of the OCU Project described in the Estimate Basis Memorandum ("EBM").[152] This Class 3 construction estimate was added to FEI's Owner's Class 3 estimate for project support services and project management to form the Base Estimate for the OCU Project.

119. The construction component of the AACE Class 3 cost estimate is based on quantities developed from designs and material take-offs completed by SMCI. SMCI then used these quantities as the basis to develop the direct and indirect costs.[153] An external independent review verified and validated that the estimate and criteria and requirements had been met.[154]

120. FEI's Owner's portion of the cost estimate was developed using an established internal cost estimating process used in other approved CPCN project applications. The process began with defining the purpose of the estimate, followed by a plan (in the form of scheduled activities) of how to acquire information to complete, verify, and assemble the estimate for the required class of estimate in the Work Breakdown Structure ("WBS") format. Using a combination of internal experience and knowledge, and external support for specialized services, FEI undertook the planning process and completed the planning deliverables listed in AACE RP 97R-18, such as:[155]

(a) Defining the project delivery method;

(b) Developing a project execution strategy;

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152 Exhibit B-1-2, Updated Application, Appendix A-3

153 Exhibit B-1-2, Updated Application, pp. 85-86.

154 Exhibit B-1-2, Updated Application, p. 86.

155 Exhibit B-2, BCUC IR1 32.2.

(c) Obtaining permits;

(d) Identifying stakeholders; and

(e) Developing the WBS for all Project Services work packages.

121. The Owner's cost estimate takes into account a project-specific organization developed by the FEI project management team and internal subject matter experts. FEI verified the Owner's cost estimate through multiple internal reviews.[156]

(b) FEI Recently Updated Key Components of the Project Cost Estimate

122. In March 2023, FEI updated both the construction and Owner's cost component of the Base Estimate for the OCU Project. The scope of the update was (1) rate increases for labour and materials, and (2) increases to material cost, which effectively updated the estimate to 2023 dollars based on the same route alignment, production rates for contractors, work duration and construction season.[157]

123. FEI retained a consultant to assist with updating the construction component of the OCU Project cost estimate. A review of the entire Base Estimate by SMCI or another third-party engineering consultant was not required because the pipeline alignment had not changed, meaning that the quantities and productivity factors remained unchanged within the revised cost estimate and only updates to rates and vendor pricing were required.[158]

124. The key factors influencing production rates or productivity for major work activities are project specific and are not impacted by the passage of time unless, in general, there are technological advances, changes in tools and equipment and improvements to working conditions. In the case of the OCU Project, none of these factors have changed. Some common examples of project-specific factors are project location, the route of the pipeline, weather, geologic and soil characteristics, means and methods, and quantity of work.[159] In the case of the OCU Project, as noted in the Supplementary Filing, "the alignment of the pipeline route and the

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156 Exhibit B-14, BCUC IR2 57.1; Exhibit B-38, CEC Supplementary IR1 7.1.

157 Exhibit B-35, Supplementary Filing, p. 7.

158 Exhibit B-38, CEC Supplementary IR1 3.2.

159 Exhibit B-36, BCUC Supplementary IR1 16.2.

construction approach described in the Updated Application remained the same."[160] As such, there was no change in any of the influencing project-specific factors that would impact production rates for the major activities on the OCU Project.[161]

125. FEI used bids from two recent projects (i.e., the EGP and IGU projects) to inform the updated labour and equipment rates for the OCU Project:[162]

- The overall labour increase of approximately 8.9 percent was determined by summing each of the average 2023 rates and computing the total percentage change from the sum of the corresponding original SMCI rates (from 2020) by simple division. The overall average increase was then applied to each labour resource contained within the cost estimate.[163]

- The overall equipment increase of 8.8 percent was determined by summing the EGP project's equipment rates and computing the total percentage change from the sum of the original SMCI equipment rates (from 2020) for the corresponding equipment by simple division. The overall average increase was then applied to all equipment resources contained within the cost estimate.[164]

126. Using the rates for both the IGU and EGP projects is a reasonable approach because they are based on contracts that have been executed or will be executed in 2023 and thus reflect the current market rates for labour and equipment.[165]

127. The rates for subcontractors were adjusted in a similar fashion as the labour and equipment rates discussed above. First, an analysis was performed to determine the most impacted subcontracts to the estimate. FEI determined that four subcontractors met the criteria: blasting, clearing and grubbing, non-destructive testing and the HDD. Subsequently, FEI obtained

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[160] Exhibit B-35, Supplementary Filing, p. 7.

[161] Exhibit B-36, BCUC Supplementary IR1 16.2.

[162] Exhibit B-36, BCUC Supplementary IR1 16.4.

[163] Exhibit B-36, BCUC Supplementary IR1 16.5.

[164] Exhibit B-36, BCUC Supplementary IR1 16.5.

[165] Exhibit B-36, BCUC Supplementary IR1 16.7; Exhibit B-38, CEC Supplementary IR1 4.3.

updated quotations from contractors' 2020 quotations. The rates provided by the four subcontractors were used to update the rates.[166] For all other subcontractors the annual BC CPI index of an approximately 9.9 percent increase from 2020 to 2022 was applied.[167]

128. FEI obtained updated quotes from vendors for the line pipe and facilities materials. These new values were used in the estimate as direct inputs without any normalizing.[168]

129. FEI determined that the percentage increase for the Owner's costs is approximately 7.97 percent based on the total estimated salary increases from 2021 to 2023. FEI applied the average percentage increase from 2021 to 2023 to both project services and engineering costs that made up the total Owner's costs. FEI used this approach because the estimated increases to project services and engineering costs are primarily due to salary increases and typically are the same across the industry, with some inherent variations when there is a labour shortage or changes in market conditions, neither of which currently apply to the OCU Project. [169]

130. Similar to the labour and equipment costs, the Owner's costs estimate was analyzed to establish the top contributors to the overall estimate total. The rates for these job titles were compared between the initial FEI 2020 rates and the current 2023 rates, with the average increase applied to all Owner's costs. The updated Owner's costs estimate in this Supplementary Filing also include FEI's most up-to-date understanding of implications of the requirements of an agreement with Indigenous communities on the Project.[170] Details and a breakdown of increase in Owner's costs were provided in the response to CEC Supplementary IR1 7.1.[171]

131. FEI confirmed that it updated all aspects of the Base Estimate (labour, equipment and materials) to reflect 2023 market prices. In addition, contingency, management reserve, escalation, and AFUDC were updated to reflect changes to the Base Estimate. As described above,

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166 Exhibit B-35, Supplementary Filing, p. 8.

167 Exhibit B-35, Supplementary Filing, p. 8.

168 Exhibit B-35, Supplementary Filing, p. 8.

169 Exhibit B-36, BCUC Supplementary IR1 16.13.

170 Exhibit B-35, Supplementary Filing, p. 8; Exhibit B-36, BCUC Supplementary IR1 16.14.

171 Exhibit B-38.

FEI did not revise the productivity factors and the quantities of labour and materials as they were not impacted by the passage of time.[172]

132. The OCU Project updated cost estimate of $327.410 million is based on the following: [173]

- An updated construction capital cost estimate (Base Estimate) of $222.268 million in 2023 dollars developed based on the methodology discussed in Section 3.2 of the Supplementary Filing;

- An updated contingency estimate of $28.400 million in 2023 dollars (approximately 12.8 percent of the updated construction capital cost estimate), which provides a total capital budget at a P50 confidence level as determined by Validation Estimating LLC, USA ("Validation Estimating") and provided in Confidential Appendix A-1 of the Supplementary Filing;

- A recommended P70 management reserve of $27.800 million (approximately 12.5 percent of the updated construction capital cost estimate) as determined by Validation Estimating and provided in Confidential Appendix A-1 of the Supplementary Filing;

- A P50 escalation value of $10.185 million during the project from 2023 to 2026[174], as determined by Validation Estimating and provided in Confidential Appendix A-2 of the Supplementary Filing, applied to a base cost estimate of $222.268 million plus a contingency of $28.400 million. The escalation is used to convert the project capital cost estimate from 2023 dollars to as-spent dollars;

- An updated estimate of $0.555 million for the regulatory review of the proceeding from 2018 to 2023, including actual spending of approximately $0.235 million up to March 2023, recorded in the proposed OCU Application and Preliminary Stage

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172 Exhibit B-42, BCSEA Supplementary IR1 33.1; Exhibit B-36, BCUC Supplementary IR1 16.2

173 Exhibit B-35, Supplementary Filing, pp. 9-10.

174 No escalation applied on actual costs incurred by FEI prior to April 2023.

Development Costs Deferral Account, as further discussed in Section 4.2 of the Supplementary Filing;

- An actual amount of $17.706 million for the project development costs from 2018 to March 2023, with $0.902 million recorded in the proposed OCU Application and Preliminary Stage Development Costs Deferral Account, as further discussed in Section 4.2 of the Supplementary Filing, and the remaining $16.804 million capitalized as pre-construction development costs. Project development costs include all of the costs associated with developing an AACE Class 3 cost estimate in accordance with AACE International Recommended Practices Nos. 18R-97 and 97R-18 as required by the BCUC's CPCN Guidelines as well as additional work required to advance the Project to date; and

- AFUDC, assumed at FEI's approved 2023 AFUDC rate of 5.46 percent, which is equal to FEI's after-tax weighted average cost of capital.[175]

133. The accuracy range for the cost estimate in the Application was +19/-16 percent (to one decimal place this range is +18.8/-15.5 percent). In the Supplementary Filing the accuracy range for the cost estimate, stated on page 12 of Appendix A-2 of the Validation Estimating Escalation Report – Revised Final, was computed as +18/-16 percent (to one decimal place this range is +18.4/-15.6 percent). The small changes are due to rounding in the model when running the Monte Carlo simulation.[176]

134. The OCU Project will result in a cumulative delivery rate impact of 2.37 percent by 2027 when all assets as well as closing costs have entered rate base. Over the 70-year analysis period, the PV of the incremental revenue requirement is approximately $331.711 million, and the levelized delivery rate impact is 1.78 percent or $0.093 per GJ. Table 4-2 in the Supplementary Filing summarizes the change in levelized delivery rate impact over the 70-year analysis period

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[175] As proposed in the 2023 Annual Review. The actual AFUDC will be calculated based on approved AFUDC rate at the time of construction.

[176] Exhibit B-36, BCUC Supplementary IR1 16.16; Exhibit B-41, BCOAPO IR Supplementary IR1 5.1.

between the Updated Application and this Supplementary Filing, demonstrating that the change is small, from 1.62 percent to 1.78 percent.[177]

H. FEI HAS IDENTIFIED AND ACCOUNTED FOR PROJECT RISK

135. The evidence demonstrates, and the BCUC should find, that FEI has identified and accounted for Project risks.

136. 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.[178]

137. FEI also retained 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 113R.[179]

138. FEI will hold contingency, management reserve and escalation funds in addition to the Project base cost estimate to address all foreseeable risks.[180] The choice of a P50 level of confidence for the contingency estimate aligns with industry practice, was confirmed by a leading industry expert, and is appropriate to establish a contingency amount.[181]

139. As described above, the contingency estimate and management reserve and escalation value were updated in the Supplementary Filing.[182]

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177 Exhibit B-35, Supplementary Filing, pp. 12-16.

178 Exhibit B-1-2, Updated Application, p. 88.

179 Exhibit B-1-2, Updated Application, p. 88; Exhibit B-35, Supplementary Filing, pp. 12-16, Appendix A-1, p. 5.

180 Exhibit B-1-2, Updated Application, p. 88.

181 Exhibit B-2, BCUC IR1 31.1.

182 Exhibit B-35, Supplementary Filing, pp. 9-10.

PART FIVE: OCU APPLICATION AND DEVELOPMENT COSTS DEFERRAL ACCOUNT

140. Pursuant to sections 59 to 61 of the UCA, FEI is seeking approval of a new non-rate base deferral account, called the "OCU Application and Preliminary Stage Development Costs Deferral Account". The account will provide deferral treatment of the costs of preparing this Application and Preliminary Stage Development Costs, and attract FEI's after tax weighted average cost of capital. FEI submits that the requested deferral treatment, which is consistent with prior BCUC approvals, is just and reasonable.

141. The deferred costs include:[183]

- CPCN Application Costs related to expenses incurred for the regulatory process to review the OCU Project CPCN Application. The cost estimate is based on a written process with an expected total of four rounds of IRs with expenses for external legal counsel, consultant costs, BCUC costs, and BCUC approved intervener costs; and

- Project Development Costs, which can be further broken down into the following:

  - Preliminary Stage Development costs 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 the Application; and

  - Pre-Construction Development Costs include the costs related to the front-end engineering and design, CPCN development costs including environmental assessments, and Indigenous and stakeholder consultations.

142. Table 4-3 of the Supplementary Filing provides the updated estimate of Application costs to the end of the regulatory process as set out in Order G-106-23 as well as actual preliminary stage development costs and pre-construction development costs up to March 2023 associated

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[183] Exhibit B-35, Supplementary Filing, p. 14.

with the OCU Project. Consistent with the approved treatment in past FEI projects, FEI proposes the following:[184]

(a) The pre-construction development costs associated with the OCU Project will be capitalized by transferring to construction work-in-progress (CWIP) on January 1, 2024; and

(b) The remaining costs in the proposed deferral account, i.e., the Application costs, including financing and any income tax recovery, estimated to be a credit of $1.249 million (at December 31, 2023), will be transferred to rate base on January 1, 2024, following a BCUC decision on the Application, and amortized over a three-year period.

143. The proposed three-year amortization period for the OCU Application and Preliminary Stage Development Costs deferral account is consistent with similar deferral account treatment approved for recent FEI CPCN applications.[185]

144. The requested approval provides FEI with the ability to recover costs associated with this beneficial Project from customers in a manner that promotes inter-generational equity.

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184 Exhibit B-35, Supplementary Filing, pp. 14-15.

185 Exhibit B-2, BCUC IR1 33.4. See also BCUC Decision and Order C-2-21 regarding the PGR Project, pp 32-34.

PART SIX: FEI WILL MITIGATE ENVIRONMENTAL AND ARCHAEOLOGICAL IMPACTS

145. FEI expects minimal environmental and archaeological impacts for the OCU Project Based on its preliminary assessment. Potential environmental impacts of the Project can be mitigated through the implementation of standard best management practices and mitigation measures. Impacts to construction timelines and costs as a result of encountering species at risk, fish habitat, or contaminated soil or groundwater can be minimized through additional investigations during the detailed engineering phase prior to construction.[186]

146. FEI's identification and preliminary assessment of potential effects of the Project is appropriate for the stage of its development and consistent with the level of detail required for a CPCN application. Project development is necessarily an iterative process and it would not be in its customers' interest for FEI to advance the development of this Project's detailed plans, including its detailed design and associated environmental management plans and mitigation measures, prior to receiving the BCUC's approval. As a result, project and site-specific management plans will be developed during the detailed engineering phase of the Project. These plans will incorporate standard practices for construction, as well as site and/or sensitivity-specific measures as-needed, dependent on detailed engineering design, which has yet to be developed.[187]

147. FEI will undertake further environmental assessments as required, and develop environmental mitigation measures and environmental management plans during the detailed engineering and contractor Request for Proposal ("RFP") phases of the Project. These further assessments, measures and plans are required in order to apply to the BCER for an *Oil and Gas Activities Act* ("OGAA") permit, as well as other permits.[188]

A. ENVIRONMENTAL RISK OF PROJECT IS LOW AND IMPACTS CAN BE MITIGATED

148. FEI retained Hemmera Envirochem Inc. ("Hemmera") to provide a preliminary environmental assessment of the three feasible alternatives and to provide a basis for the

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186 Exhibit B-1-2, Updated Application, p. 98.

187 Exhibit B-20, PIB IR1 31.1 and 56.1.

188 As described in Section 7 of the Updated Application (Exhibit B-1-2).

completion of detailed assessments and preparation of environmental management plans prior to construction commencement.[189]

149. The assessment was based on a combination of a desktop review of available information and Preliminary field reconnaissance ("PFR") surveys. The assessment was completed to identify and describe the potential impacts to the biophysical environment from the Project and determine recommended impact mitigation. The assessment reviewed the areas of the three feasible alternatives while the PFR was completed for the preferred alternative.[190]

150. The Penticton Indian Band (the "PIB") and Westbank First Nation (the "WFN") provided technicians to participate in the environmental PFR and were provided opportunity to review and comment on the Pre-Construction Site Assessment report (habitat assessment).[191]

151. Based on this preliminary assessment, the overall environmental risk of the Project is low and any potential environmental impacts from the Project can be mitigated through the application of standard environmental best management practices and mitigation measures.[192]

152. The Environmental Overview Assessment ("EOA") identifies significant natural features, such as fish, wildlife, and terrestrial habitat that could potentially be impacted by Project construction, as well as areas that could impact construction, costs, and timelines of the Project. The EOA was provided to Indigenous groups for their review and comment, including the PIB and WFN who provided technicians to participate in the environmental PFR. Where comments were received, they were reviewed and incorporated, or will be addressed in the Environmental Management Plan ("EMP").[193]

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189 Exhibit B-1-2, Updated Application, p. 98.

190 Exhibit B-1-2, Updated Application, p. 99; detailed descriptions of Project related biophysical impacts and recommended mitigation can be found in Section 6.0 of the EOA filed as Appendix F to the Updated Application.

191 Exhibit B-20, PIB IR1 43.1.

192 Exhibit B-1-2, Updated Application, p. 99.

193 Exhibit B-20, PIB IR1 43.1.

153. Reports provided by the Syilx[194] Traditional and Ecological Knowledge Keepers ("TEKK"), a group of individuals from communities across the Syilx traditional territory, will also be used in further project design and in development of the EMP. [195]

154. The construction contract will include the EMP, which specifies all of the environmental requirements for the Project. The contractor will be required to prepare an environmental protection plan ("EPP"). The contractor will be responsible for scheduling their work locations and activities to meet the contract requirements and in accordance with their EPP.[196]

155. Though FEI paused work on the EMP while it sought consent from Indigenous groups for the Project, there is sufficient time in the current OCU Project schedule to complete the EMP prior to submission of permit application(s) with the BCER.[197]

156. 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 EMP.[198]

B. EXTENT OF ARCHAEOLOGICAL ASSESSMENT IS APPROPRIATE TO DATE

157. The evidence, discussed below, demonstrates that the extent of archaeological assessment is appropriate for the stage of the Project. FEI has outlined a reasonable plan to continue with that work as the Project proceeds.

(a) There Have Been Two AOAs: One by Golder and One Facilitated by the PIB

158. FEI retained Golder Associates Ltd. ("Golder") to complete an Archaeological Overview Assessment ("AOA") of the Project[199] to assess the potential for archaeological and/or cultural heritage resources within the Project area. Golder was tasked with determining the necessity

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194 People of the Okanagan Nation.

195 Exhibit B-20, PIB IR1 43.1.

196 Exhibit B-2, BCUC IR1 36.2.

197 Exhibit B-36, BCUC Supplementary IR1 19.3.

198 Exhibit B-4, CEC IR1 30.1.

199 See Exhibit B-1-2, Updated Application, Appendix G: Alternative 3 Archaeological Overview Assessment.

and, if required, the scope of additional archaeological assessment prior to the commencement of ground disturbing activities.

159. The AOA consisted of a desktop review that included examination of an existing archaeological potential model along the route of the preferred alternative. PFR work has taken place and will continue throughout the detailed engineering phase of the Project. Information obtained during the PFR will be referenced during the detailed engineering phase and will inform future planned archaeological investigations.[200]

160. A confidential AOA was facilitated by the Penticton Indian Band, and conducted by the TEKK. The recommendations of this AOA will be addressed during the Archaeological Impact Assessments ("AIA"). [201]

(b) There Will Be an AIA, Permitting and Ongoing Monitoring as Required

161. As is typical for projects of this nature, potential impacts to archaeological and historic heritage sites will be further assessed in the AIA, which will be initiated during the detailed engineering phase of the Project. It is anticipated that the majority of the AIA will be completed prior to construction, though it is understood that AIA of portions of the Project area may have to be conducted concurrent with construction (e.g., areas with potentially deep buried resources, access constraints or where ground conditions are not suitable for manual testing). A subsurface testing program will be undertaken, where required. The AIA will allow for development of site-specific mitigation strategies to offset any potential impacts to archaeological and historic heritage sites.

162. FEI will obtain archaeological permits during the detailed engineering phase of the Project and if necessary, during the construction phase of the Project.[202]

163. If required, archaeological monitoring will be undertaken during all archaeologically sensitive aspects of the work program. The designated archaeological monitor will have "stop

[200] Exhibit B-1-2, Updated Application, p. 104.

[201] Exhibit B-2, BCUC IR1 35.1.

[202] Exhibit B-1-2, Updated Application, p. 106.

work authority" in the event that works underway have the potential to result in unauthorized impacts to archaeological, historic heritage or cultural resources. [203]

[203] Exhibit B-1-2, Updated Application, p. 106.

PART SEVEN: FEI'S ENGAGEMENT ACTIVITIES WILL CONTINUE TO BE ADEQUATE AND APPROPRIATE

164. FEI's consultation and engagement with stakeholders and Indigenous groups to date have been appropriate and reasonable, reflecting the Project's stage of development and schedule. FEI has demonstrated commitment to responding to feedback from Indigenous groups and stakeholders. FEI will continue engaging with Indigenous groups and stakeholders throughout the regulatory process, preconstruction and close out phases of the OCU Project.[204]

165. As described in the sections below:

(a) FEI's engagement with Indigenous groups on the Project has been robust and will continue;

(b) Public consultation to the date on the Project has been sufficient and will continue; and

(c) FEI has appropriately managed relations with directly affected landowners.

A. FEI ENGAGEMENT WITH INDIGENOUS GROUPS IS MEANINGFUL AND ONGOING

166. FEI submits that its evidence demonstrates a level of engagement with Indigenous groups that is appropriate for this stage of the Project planning and development, and for the BCUC regulatory review process. FEI's engagement is ongoing.

(a) Overview of Engagement Approach and Steps

167. FEI is committed to building strong working relationships with Indigenous groups guided by FEI's Statement of Indigenous Principles.[205] FEI recognizes that the potential impacts of the Project on the title, rights, and interests of affected Indigenous groups must be identified and avoided or mitigated as appropriate.

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[204] Exhibit B-35, Supplementary Filing, p. 1.

[205] Exhibit B-1-2, Updated Application, Appendix I-1.

168. To achieve this, FEI has employed an engagement approach that has been thorough, timely, and meaningful. FEI is also committed to working with local Indigenous groups to create project benefits, through capacity building and economic opportunities.[206]

169. FEI's engagement with Indigenous groups with asserted interests in the OCU Project area began in 2019, at the initial stages of Project development. FEI continued engagement with Indigenous groups following the filing of the CPCN application in December 2020. In January 2021 FEI sent a notification and information letter by email to the WFN, Lower Similkameen Indian Band ("LSIB"), Upper Nicola Indian Band, Okanagan Nation Alliance, Nooaitch Indian Band, and the PIB. The letter explained that FEI submitted an application to the BCUC for a CPCN; provided information on how the group could register as an interested party, including contact information, website address, and timeline; notified the Indigenous groups of a Heritage and Conservation permit application; and provided contact information for FEI where any comments, questions or concerns could be directed. FEI's log of Indigenous engagement to date is included as Appendix D of the Supplementary Filing.[207]

170. FEI has provided its plan for further engagement through the remainder of the Project development and execution. FEI explained that it continues to engage with Indigenous and local communities to identify opportunities for economic participation in the Project, including contracts for goods and services, or employment with FEI or its contractors.[208]

171. Crown consultation with Indigenous groups will be part of the ongoing regulatory process, which includes the BCER permitting process.

(b) Engagement with Lower Similkameen Indian Band

172. In May 2021 the BCER notified FEI that the LSIB had provided its position on the OCU Project to the BCER. LSIB reviewed the shape files and noted that the work is primarily within

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206 Exhibit B-35, Supplementary Filing, p. 18.

207 Exhibit B-35, Supplementary Filing, p. 18. Updates were provided in Exhibit B-14, BCUC IR2 62.1; Exhibit B-22, BCUC IR3 70.1; and Exhibit B-36-1, BCUC Supplementary IR1 22.1.

208 Exhibit B-4, CEC IR1 32.1.

PIB area of responsibility, and that the LSIB supports any comments and request brought forth from the PIB.[209]

(c) Engagement with Westbank First Nation

173. Engagement with WFN continued after the Original Application was filed. WFN has provided a letter of conditional consent for the OCU Project. The condition is that archaeology work is conducted and WFN receives a minimum of three weeks' notification to schedule WFN field works. Other engagement activities included finalizing and signing a Capacity Funding Agreement in February 2021, which outlines the work plan and engagement process WFN and FEI will undertake on the OCU Project; and engagements such as archaeology, geotechnical and environmental field work, report reviews and general administrative engagements.[210]

(d) Engagement with Penticton Indian Band

174. FEI's engagement with the PIB continued after the filing the Original Application. It has focussed on engagement processes and activities outlined in the Capacity Funding Agreement. Examples of activities include archaeology, geotechnical and environmental field work, report reviews and engagements; regulatory application information, such as the BCER; and community-led studies such as the Use and Occupancy studies and report, and the TEKK studies and reports.[211] FEI provided provide an update of all meetings, other communications and actions with the PIB from April 2021 to date in its response to BCUC Supplementary IR1 22.1.[212]

175. FEI is committed to working closely with the PIB throughout the life of the Project and to ongoing dialogue.[213] FEI remains optimistic in obtaining the PIB's consent for the OCU Project which has not yet been determined by the PIB.[214] FEI provided additional details on the status

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[209] Exhibit B-35, Supplementary Filing, p. 19.

[210] Exhibit B-35, Supplementary Filing, p. 19.

[211] Exhibit B-35, Supplementary Filing, p. 19. See also Exhibit B-14, BCUC IR2 62.1.

[212] Exhibit B-36.

[213] Exhibit B-20, PIB IR1 28.4.

[214] Exhibit B-41, BCOAPO Supplementary IR1 8.3. See also Exhibit B-41-1, confidential response to BCOAPO Supplementary IR1 8.2.

of its engagement in confidential IR responses.[215] In order to meet the Project timeline outlined in the Supplementary Filing, FEI would need to reach an agreement with the PIB before the end of 2023.[216] The Supplementary Filing takes into account FEI's most up-to-date understanding of the implications of the requirements of an agreement on the OCU Project, including with respect to cost and schedule.[217] FEI provided additional details on these costs in confidential IR responses.[218]

176. FEI is committed to obtaining the PIB's consent for the OCU Project. If FEI is unable to obtain the PIB's consent, FEI will not proceed with the OCU Project as currently proposed (i.e., FEI will not proceed with the Preferred Alternative). Should this occur, FEI may consider other alternatives outlined in its Application to meet customer demand in the Okanagan area and would engage with affected Indigenous communities as necessary.[219] FEI has not investigated other alternatives in any detail beyond the alternatives presented in the Updated Application.[220]

177. FEI confirms that it will advise the BCUC whether or not FEI and the PIB are able to reach an agreement with respect to the OCU Project (i.e., FEI will advise the BCUC of either outcome) and expects that the timeframe for informing the BCUC would be the same regardless of the outcome.[221]

178. In its decision on Order G-212-23, the Panel agreed with FEI's submissions that there is no requirement for Indigenous consultation to be complete before the BCUC issues a CPCN for the OCU Project. The BCUC's obligation is to assess the adequacy of Indigenous consultation as part of its decision-making process, to the point at which the CPCN is issued or denied. Therefore,

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215 Exhibit B-36, BCUC Supplementary IR1 22.2; Exhibit B-45, BCUC Panel Confidential IR1 1.1, 1.1.2, 1.2.1, 1.3, 1.3.1, 1.3.2, 1.4.

216 Exhibit B-41, BCOAPO Supplementary IR1 8.5.

217 Exhibit B-35, Supplementary Filing, p. 19.

218 Exhibit B-38, CEC Supplementary IR1 7.1, 10.1; Exhibit B-45, BCUC Panel Confidential IR1 1.1.1, 1.2.

219 Exhibit B-44, BCUC Panel IR 1.3; Exhibit B-41, BCOAPO Supplementary IR1 8.6.

220 Exhibit B-41, BCOAPO Supplementary IR1 8.6.

221 Exhibit B-42, BCSEA Supplementary IR1 38.2.

the absence of a definitive agreement between FEI and the PIB is not an obstacle to the parties submitting their final arguments for the OCU Project.[222]

179. FEI submits that there is sufficient evidence on the record to support a conclusion by the BCUC that there has been adequate Indigenous engagement to this stage, including with the PIB.[223]

180. The OCU Project proceeding has now been ongoing since 2020, and since that time, the need for the Project to serve the growing load in the Okanagan region has only become more imminent.[224] FEI needs to reach a conclusion on whether the proposed alternative can move forward shortly, both from the PIB and the BCUC. FEI anticipates knowing whether it will be able to reach an agreement with the PIB in Q3 2023, or shortly thereafter.[225]

B. FEI HAS UNDERTAKEN SIGNIFICANT PUBLIC CONSULTATION TO DATE AND IT IS ONGOING

181. Consultation, engagement and communication are integral components of FEI's project development process. Accordingly, FEI created a Consultation and Engagement Plan that sets out the general approach to consultation, engagement and communications activities with respect to the work on the OCU Project.[226] FEI's public consultation and communication activities have been sufficient, appropriate, and reasonable to meet the requirements of the CPCN guidelines.

182. FEI's log of Project-specific stakeholder and local government consultation activities to date is included as Appendix C of the Supplementary Filing.[227] In summary:

- FEI's consultation and engagement on the Project began in late 2019, with early consultation and engagement on the Project. FEI engaged early with Indigenous groups and consulted with local governments including City of Penticton, the RDOS, City of Kelowna, and City of West Kelowna.

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222 Exhibit A-36.

223 Exhibit B-44, BCUC Panel IR 1.1.1.

224 Exhibit B-44, BCUC Panel IR 1.2.

225 Exhibit B-44, BCUC Panel IR 1.3.

226 Exhibit B-1-2, Updated Application, p. 107. This plan is included as Appendix H-1 to the Updated Application.

227 Exhibit B-35, Supplementary Filing, p. 17.

- In 2020, as Project planning continued, the preferred alternative was refined and FEI presented this revised route to Indigenous groups and local government officials. The Project was also introduced to the public, potentially impacted landowners, and other stakeholders, including customers, residents, businesses, stakeholder groups and organizations. Throughout this consultation and engagement, FEI tracked the issues and concerns raised. FEI will continue to work with Indigenous groups and stakeholders to address any outstanding. [228]

- FEI continued to engage with stakeholders and local government after the CPCN application filing. This has included:

  - Bi-weekly with Penticton to provide project updates, seek feedback on the project, and create a Terms of Reference Agreement to address the use of city-owned land for which the OCU Project requires Surface-Rights-of-Way, and timelines for project-related permit reviews and approvals from Penticton.[229]

  - Bi-weekly meetings with the RDOS to provide Project updates, seek feedback on the Project, and create an agreement regarding FEI access to, and use of, the Campbell Mountain Landfill for temporary workspace.[230]

183. FEI has responded to concerns raised by members of the public has sought to address them.[231] FEI has refined the route to address landowner feedback.[232]

184. FEI acknowledges a number of letters have been filed in this proceeding by members of the public. The overarching theme in most of the letters is concern about greenhouse gas emissions. As described above, the OCU Project has been initiated to allow FEI to serve existing and future customers, consistent with its obligations as a public utility under the UCA. As

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228 Exhibit B-1-2, Updated Application, p. 107.

229 Exhibit B-35, Supplementary Filing, p. 17.

230 Exhibit B-35, Supplementary Filing, p. 17.

231 Exhibit B-1-2, Updated Application, p. 117.

232 Exhibit B-2, BCUC IR1 39.2.

described in Part Eight below, the OCU Project plays an important role in achieving provincial energy and climate objectives.

185. FEI has confirmed that it will continue to engage proactively with stakeholders and the public throughout the lifecycle of the project. In particular, FEI will continue to:[233]

(a) Communicate with landowners through meetings, phone calls and emails throughout the course of the Project;

(b) Communicate with stakeholders, including pertinent government officials and agencies at the municipal and regional levels, landowners, stakeholder groups, and the general public;

(c) Identify opportunities to continue this engagement with local stakeholders, including through meetings, phone calls, telephone town hall/public information sessions, and informal community coffee chats; and

(d) Communicate broadly through paid media and advertisements, in the communities that will be most affected. This includes advertisements to inform Penticton and Naramata residents of engagement opportunities and distribution of construction notifications to nearby residents and businesses.

C. FEI HAS REACHED SHORT-TERM AGREEMENTS WITH DIRECTLY IMPACTED LANDOWNERS

186. All directly impacted landowners have responded to FEI's notification regarding the Project.[234] FEI has refined the route to address landowner feedback, constructability challenges, and contingency plans.[235]

187. FEI's objective is to reach mutually acceptable negotiated agreements with landowners, and negotiations have been fruitful.[236] With the exception of one property which FEI has purchased (due to landowner preference), FEI has successfully negotiated agreements to grant a

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233 Exhibit B-1-2, Updated Application, p. 117.

234 Exhibit B-2, BCUC IR1 39.1. See also Exhibit B-22, BCUC IR3 69 series.

235 Exhibit B-2, BCUC IR1 39.2.

236 Exhibit B-2, BCUC IR1 39.2.1. A confidential response on strategy was provided in Exhibit B-16, BCOAPO IR2 13.2.

statutory right-of-way ("SRW") with all landowners directly along the OCU Project route; no properties were expropriated.

188. The certainty and benefits provided by these agreements does depend on obtaining a BCUC decision prior to December 31, 2023. These agreements involve two steps: the first step is a non-refundable deposit paid to the landowners when signing the agreement; the second step is the payment of the remainder of the agreed compensation to the landowners upon BCUC approval of the OCU Project, prior to December 31, 2023. If BCUC approval is not obtained by the December 31, 2023 deadline, the agreements will automatically terminate unless FEI succeeds in negotiating amendments with the landowners.[237]

189. If FEI does not receive BCUC approval of the OCU Project by the December 31, 2023 deadline and FEI is not successful in negotiating amendments to the agreements, this may impact project timing. FEI will need to negotiate new SRW acquisition agreements with the landowners and explore expropriation in the event FEI is unable to reach agreement with the landowners. With either approach, FEI estimates an increase in SRW compensation payments of between 20 percent and 40 percent due to increases in land values since the agreements were signed in 2020/21.[238]

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[237] Exhibit B-36, BCUC Supplementary IR1 20.1.

[238] Exhibit B-35, Supplementary Filing, p. 18.

PART EIGHT: ALIGNMENT WITH THE PROVINCIAL ENERGY AND CLIMATE OBJECTIVES

190. Section 46(3.1)(a) of the UCA requires the BCUC to consider "the applicable of British Columbia's energy objectives". In the case of the OCU Project, most of the objectives are inapplicable. As discussed in this Part, the Project primarily supports objective (k) to encourage economic development and the creation and retention of jobs. The Project will play a role in achieving, i.e., is not inconsistent with, provincial energy and climate objectives to reduce GHG emissions.

A. SUPPORT OF BC ENERGY OBJECTIVE TO ENCOURAGE ECONOMIC DEVELOPMENT

191. The Project encourages economic development and the creation and retention of jobs in two ways.

192. First, the Project provides vital capacity to serve the growing energy needs of homes, business and industry in the central and north Okanagan regions. As noted above, Kelowna has been one of the fastest growing cities in Canada in the past decade and is forecast to grow at a similar rate in the coming two decades. The continued supply of safe, reliable and affordable energy to new and existing customers in the region will support economic activity and the creation and retention of jobs.[239] In the absence of the Project, these areas are expected to experience a capacity shortfall in the winter peak of 2026/2027.

193. Second, the construction of the Project is expected to have positive employment and economic impacts in the central and north Okanagan regions. In particular, the procurement of local materials, and the use of local services such as lodging and dining, will contribute local economic activity.[240] Past experience has borne this out. For example, between 2014 and 2019, FEI invested approximately $300 million in the LMIPSU project. FEI and its contractors supported more than 350 suppliers in over 40 municipalities and Indigenous communities in Metro Vancouver and across British Columbia. Of this investment, $263 million was spent in goods,

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[239] Exhibit B-2, BCUC IR1 40.1.

[240] Exhibit B-2, BCUC IR1 40.1.

materials, and services for the project. LMIPSU project general contractors spent 5.5 percent of their BC-based spend on Indigenous-affiliated businesses.[241]

B. THE PROJECT PLAYS AN IMPORTANT ROLE IN ACHIEVING PROVINCIAL ENERGY AND CLIMATE OBJECTIVES

194. The Project will play a role in achieving, i.e., is not inconsistent with, the provincial energy and climate objective to reduce greenhouse gas emissions, which is referenced in British Columbia's energy objectives (g), (h) and (i)). The OCU Project is consistent with transitioning to a low carbon future where the gas system may supply less energy but supply similar levels of peak capacity.

(a) Gas Is Required to Meet Peak Energy Requirements in a Low Carbon Future

195. The fact that the OCU Project is a capacity project – i.e., it is needed to support winter peak energy demand in the Okanagan Region – is relevant in the context of greenhouse gas reduction in two related respects.

- First, peak energy is a critical service which is difficult to electrify. In FEI's 2022 LTGRP, FEI filed evidence examining the impacts to the electric system associated with electrifying gas heating load in the City of Kelowna.[242] The study demonstrates that the transfer of peak demand from the gas system to the electric system creates a substantial requirement for additional electric infrastructure and associated land to address the incremental winter electric peak demand and therefore, may not be an optimal approach to decarbonization.

- Second, the gas system is specifically designed to address seasonal energy peaks with its ability to cost-effectively store large volumes of energy for long periods of time.

196. These factors together suggest that the optimal way to achieve greenhouse gas reductions while still being able to meet energy demand in winter is through integration of the

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[241] Exhibit B-20, PIB IR1 3.1

[242] FEI 2022 Long-term Gas Resource Plan Proceeding, Exhibit B-20, Kelowna Electrification Case Study.

two systems, using the gas systems storage and deliverability to complement the electric system. With an integrated approach, the gas system (including low-carbon gases) can serve much of the peak capacity requirements for space heating, water heating, and industrial loads (all mitigated through energy efficiency investments), with a share of the annual energy demand requirement being provided by the electric system.[243]

197. An example of energy efficiency would be a FortisBC customer replacing a gas furnace with a dual fuel hybrid system. In this example, the energy required for heating in the shoulder seasons would be supplied by an electric heat pump (when the heat pump efficiency is greatest) with the gas furnace providing energy for heating during the cold seasons (when the heat pump efficiency is lowest, and its capacity impacts to the electrical grid are the highest). The capacity of the gas system needed to accommodate this dual fuel integration is similar to the capacity needed by customers using gas-only equipment; however, the associated greenhouses gas emissions would be reduced by shifting shoulder season demand to the electric system via an electric heat pump.[244]

198. Accordingly, while integrating use of the gas and electric systems could result in a reduction in <u>annual</u> gas demand (and hence overall greenhouse gas emissions), there would be continued reliance on the gas system to meet overall peak <u>energy</u> needs, which is the driver of the OCU Project.[245]

(b) Gas System Can Deliver Low Carbon Energy Consistent with Government Policy

199. The gas system itself is a means for the delivery of low carbon energy. FEI's gas system, including the facilities constructed as part of this Project, will increasingly be used to deliver low carbon energy (i.e., renewable gas) to customers in the province. FEI continues to increase its supply of renewable gas in alignment with the provincial CleanBC target to achieve 15 percent

243 Exhibit B-36, BCUC Supplementary IR1 23.1.

244 Exhibit B-36, BCUC Supplementary IR1 23.1.

245 Exhibit B-36, BCUC Supplementary IR1 23.5.

renewable gas content by 2030.[246] Over the longer term to 2050, FEI envisions a future where the majority of the energy it delivers, including through the Project, is renewable. [247]

200. In May 2021, the Province supported this policy by enabling gas utilities to acquire up to 15 percent of their gas from renewable and low-carbon sources, including hydrogen, through amendments to the *Greenhouse Gas Reduction Regulation*.[248] In October 2021, CleanBC spoke further about the important role that gas infrastructure and renewable gases play in reducing emission in BC:

> B.C.'s existing pipeline infrastructure can play an important role in reducing greenhouse gases by transitioning away from delivering fossil natural gas to delivering renewable gas. B.C.'s gas utilities have been leaders in enabling this transition.
>
> To help drive this transition, we will introduce a GHG emissions cap that will require gas utilities to undertake activities and invest in technologies to further lower GHG emissions from the fossil natural gas used to heat homes and buildings and power some of our industries.
>
> Following further modelling and analysis, the cap will be set at approximately 6 Mt of CO2e per year for 2030, which is approximately 47% lower than 2007 levels. Since emissions from gas consumption are linked to industry (excluding oil and gas) and the built environment, the cap is consistent with emissions targets for those sectors.
>
> Utilities will determine how best to meet the target, which could include acquiring more renewable gases as well as supporting greater energy efficiency. Measures in CleanBC allow gas utilities to use renewables such as synthetic gas, biomethane, green and waste hydrogen and lignin to achieve this.[249]
>
> [Emphasis added.]

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246 CleanBC Plan: CleanBC: our nature. Our power. Our future. (gov.bc.ca)

247 Exhibit B-2, BCUC IR1 40.1.

248 *Greenhouse Gas Reduction Regulation*, B.C. Reg. 102/2012.

249 CleanBC Roadmap to 2030: cleanbc_roadmap_2030.pdf (gov.bc.ca).

201. CleanBC anticipates a significant transition to renewable and low carbon gases which require investment in gas infrastructure, like the OCU Project, to enable energy delivery to customers.

(c) Diversified Energy Approach Can Achieve British Columbia's Climate Goals and Is Cost-Effective

202. Guidehouse's Pathways Report[250] demonstrates that British Columbia's climate objectives can be achieved using a diversified pathway that contemplates: significant investments in energy efficiency that would reduce carbon emissions by more three million tonnes by 2050; approximately three-quarters of the energy delivered in the gas system being renewable by 2050; and, continued investment in the gas delivery system. The Guidehouse Pathways Report also demonstrates that a diversified pathway would be a more affordable and resilient pathway to achieve emissions reductions targets as compared to a pathway that focuses solely on electrification.

(d) Policy Impacts on Peak Demand May Differ from Those on Annual Demand

203. A decrease in annual demand (and by extension greenhouse gas emissions) does not necessarily mean a decrease in peak usage. In the response to BCUC Supplementary IR1 8.4,[251] FEI provided a chart which overlays the Supplementary Filing Peak Demand Forecast with the annual demand forecast based on the Diversified Energy Planning ("DEP") scenario in the 2022 LTGRP.

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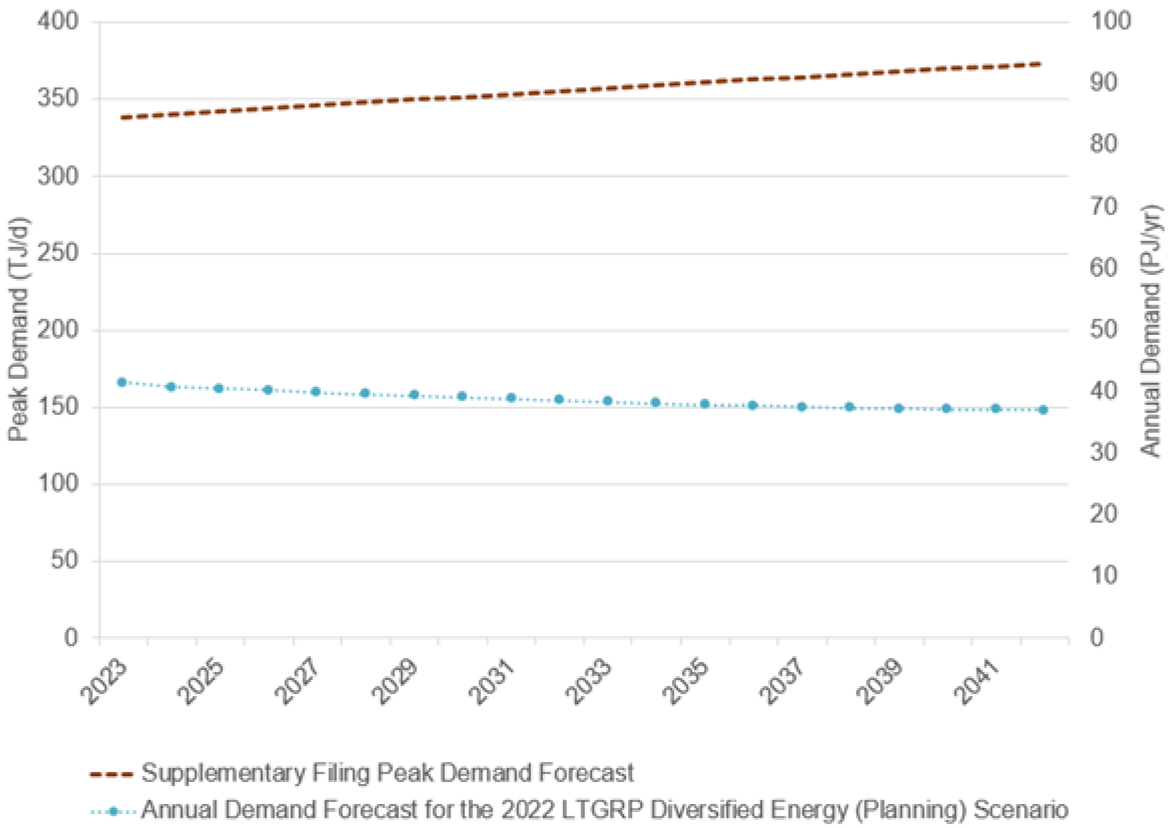
[250] Exhibit B-16, BCOAPO IR2 14.1.

[251] Exhibit 36.



204. The figure above shows a decrease in the annual demand forecast for the DEP Scenario while the Supplementary Filing Peak Demand forecast increases over the planning horizon. Although the two forecasts have some differences that make them difficult to compare directly, it illustrates FEI's expectation that the peak demand forecast would not necessarily follow the same trend as the annual demand forecast. This stands to reason. For instance, in situations where dual fuel systems are installed in buildings, continued gas deliveries to those buildings will be critical for meeting peak winter energy demand and maintaining a resilient, overall energy system in BC; therefore, even in cases where gas may only be relied on to back up electric systems, FEI anticipates that peak demand will remain the same for such customers. However, the overall annual greenhouse gas emissions are lower.

C. OCU PROJECT IS CONSISTENT WITH FEI'S MOST RECENT RESOURCE PLAN

205. The BCUC must consider FEI's most recent long-term resource plan under section 46(3.1)(b) of the UCA. FEI's LTGRP Application filed in 2022 demonstrated the merits of a diversified pathway to meet the Province's climate goals while still investing in new capacity

infrastructure such to improve FEI's ability to continue to provide gas service to customers safely, cost effectively and reliably.[252]

[252] FEI 2022 Long-term Gas Resource Plan Application, Exhibit B-1, Table 1-5, p. 1-12.

PART NINE: CONCLUSION

206. The evidence demonstrates that the OCU Project is in the public interest. The last major upgrade to the ITS was completed more than twenty years ago, and load has since grown markedly. FEI needs a long-term solution to address the expected capacity shortfall prior to the winter peak of 2026/2027. The BCUC's decision on this Application has real-life ramifications for customers in the north and central Okanagan. The Project is necessary for FEI to continue providing consistent, uninterrupted service to those customers in the coldest winter periods. This is the type of service to which all FEI customers are accustomed, and upon which they depend. The Project is also necessary to allow FEI to continue accepting requests for new service (i.e., new customers, or new loads for existing customers), without exposing existing customers in the area to greater risk of winter outages.

207. The preferred alternative (Alternative 3) provides the necessary capacity increase to maintain safe and reliable gas service to customers. It has the lowest overall impact in terms of technical design, scope, complexity, cost, construction, environmental, archaeological and societal impacts.

208. FEI respectfully submits that the BCUC should grant a CPCN and the associated deferral account on the terms set out in the Updated Application and Supplementary Filing.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated:	August 14, 2023	***[original signed by Tariq Ahmed]***
		Tariq Ahmed Counsel for FortisBC Energy Inc.