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November 19, 2020

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

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

**Re: FortisBC Energy Inc. (FEI)**

**Project No. 1599129**

**Application for a Certificate of Public Convenience and Necessity (CPCN) for the Pattullo Gas Line Replacement Project (the Application)**

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

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On August 31, 2020, FEI filed the Application referenced above. In accordance with BCUC Order G-253-20 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Diane Roy

Attachments
cc (email only): Registered Parties

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# A. PROJECT JUSTIFICATION

**1.0 Reference: INTRODUCTION**

**Exhibit B-1, Cover Letter, p. 1; Section 3.1, p. 14**

**Agreement with MoTI**

On page 1 of FortisBC Energy Inc.'s (FEI) cover letter for its application for a Certificate of Public Convenience and Necessity (CPCN) for the Pattullo Gas Line Replacement Project (PGR Project or Project) (Application), FEI states:

> The Ministry of Transportation and Infrastructure's (MoTI) Pattullo Bridge Replacement Project necessitates FEI removing its gas line from the existing Pattullo Bridge.

Further on page 14 of the Application, FEI states:

> The need to undertake the PGR Project arises from the Province's Pattullo Bridge Replacement Project, which includes the demolition of the Pattullo Bridge on which FEI's Pattullo Gas Line is affixed. The Pattullo Gas Line, which has been in operation since 1956

1.1 Please provide a copy of the agreement(s) (or similar), between the Ministry of Transportation and Infrastructure and FEI, which governs the placement of the Pattullo Gas Line on the Pattullo Bridge.

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

Please refer to Attachment 1.1 for a copy of the following agreements:

- An agreement between the Province of British Columbia (represented by the Ministry of Highways) and British Columbia Electric Company dated April 11, 1957 (Bridge Agreement); and
- An agreement in which the BC Hydro & Power Authority (British Columbia Electric Company's successor) assigned the Bridge Agreement to B.C. Gas Inc. (which is now FEI) dated July 16, 1988.

1.1.1 Please identify the relevant sections of the agreement that relate to the removal of the Pattullo Gas Line.

**Response:**

Section 2 of the Bridge Agreement provides that the Minister of Highways may terminate the agreement by giving two years notice in writing to FEI.

On termination of the Bridge Agreement, Section 3 requires FEI to remove all pipeline and attachments from the bridge and leave the bridge in a condition satisfactory to the Minister of Highways "within a reasonable time".

Further, Section 6 of the Bridge Agreement gives the Province a separate right to require the movement or alteration of the pipeline or the transmission of gas to cease if that is necessary for reconstruction, alteration, or repairs of the bridge.

1.2 Please discuss MoTI's jurisdiction for requiring the removal of the Pattullo Gas Line.

**Response:**

MoTI represents the Province of British Columbia.

MoTI's jurisdiction for requiring the removal of the Pattullo Gas Line arises in respect of the Bridge Agreement made between FEI and the Province (as included as Attachment 1.1 in the response to BCUC IR1 1.1) and/or the fact that it is responsible for carrying out the Pattullo Bridge Replacement Project, which includes the demolition of the existing Pattullo Bridge.

**2.0 Reference: PATTULLO BRIDGE REPLACEMENT PROJECT**

**Exhibit B-1, Section 3.4, p. 19**

**MoTI Schedule**

On page 19 of the Application, FEI states:

> Based on the current Project schedule, demolition of the Pattullo Bridge is scheduled to proceed by the end of 2023 after the New Bridge opens. However, MoTI has indicated that it could occur earlier than this target date due to the nature of the performance based, design-build finance contract it has entered into with its contractor who will be performing the construction and demolition work.
>
> Prior to the demolition of the existing Pattullo Bridge, FEI will need to degasify and purge the existing Pattullo Gas Line to make it safe for removal, and abandon and/or remove all associated infrastructure, as well as complete any required modifications to the existing infrastructure upstream and downstream of the Pattullo Gas Line.

2.1 Please explain the consequences to FEI if it could not meet MoTI's current 2023 target date.

**Response:**

The Bridge Agreement (as included as Attachment 1.1 in the response to BCUC IR1 1.1) provides that FEI is required to remove its pipeline and attachments from the existing Pattullo Bridge within a "reasonable time" on termination of the agreement. If a court were to find that FEI had breached the Bridge Agreement for failure to remove the pipeline and attachments within a "reasonable time", FEI could be found liable for damages flowing from the breach.

However, FEI does not admit that the current 2023 date represents a "reasonable time" to remove the pipeline and attachments. A "reasonable time" must include the time it takes to plan, design, consult, redesign after consultation, obtain all necessary approvals, and construct a new replacement gas line before removing the existing gas line on the Pattullo Bridge. Therefore, FEI does not concede that if it could not meet MoTI's current 2023 target date, it would necessarily be in breach of the agreement, nor does it concede that even if there was a breach of the agreement caused by any failure to meet the 2023 target date, that the Province or TransLink (the current owner and operator of the existing Pattullo Bridge) would be entitled to damages.

To date, neither TransLink nor MoTI have quantified the financial consequences if FEI does not meet the current 2023 target date.

FEI is committed to meeting MoTI's current 2023 target date to the extent FEI is reasonably able, as FEI believes that active co-operation between FEI and MoTI will support the success of both the Pattullo Bridge replacement and the PGR Project.

2.2 If the demolition of the Pattullo Bridge was to occur earlier than currently targeted, please discuss whether FEI would be able to meet the revised target date.

**Response:**

FEI has continued to inform the Province that the existing Pattullo Gas Line cannot be taken out of service and decommissioned until a replacement gas line is constructed and commissioned. To date, the Province has not notified FEI of an earlier demolition date for the Pattullo Bridge. As such, FEI is currently working towards a target date of commissioning the new gas line and decommissioning the existing gas line by March 31, 2023 (excluding removal of the decommissioned gas line from the Pattullo Bridge). FEI continues to meet with the MOTI and the Pattullo Bridge Replacement project team on a regular basis and based on this FEI has no reason to expect an earlier demolition date for the Pattullo Bridge.

The impacts of an earlier demolition date on FEI's Project schedule would vary based on the timing of any possible notification or the status of FEI's Project activities at that time. Should the Province indicate an earlier demolition date, FEI would assess the impacts of such a date on the Project and notify the Province and the BCUC whether FEI anticipates being able to meet the Province's revised target date and the associated impacts of the change.

FEI is targeting the March 31, 2023 decommissioning date and will make every reasonable effort to expedite Project completion.

2.2.1 Please describe the impacts that an earlier demolition date would have on FEI

**Response:**

Please refer to the response to BCUC IR1 2.2.

2.2.2 Please explain the consequence to FEI, if FEI was not able to meet the revised target date, including but not limited to any financial penalties or liability for any costs associated with a delay.

**Response:**

Please refer to the responses to BCUC IR1 2.1 and 2.2.

**3.0 Reference: DISTRIBUTION SYSTEM CAPACITY PROVIDED BY THE PATTULLO GAS LINE**

**Exhibit B-1, Section 3.5, pp. 19-20**

**Additional Distribution System Capacity Needed**

On pages 19 and 20 of the Application, FEI states:

> FEI must replace the distribution system capacity currently provided by the Pattullo Gas Line in order to continue to supply natural gas safely and reliably to customers in Burnaby, New Westminster and Coquitlam. The Pattullo Gas Line currently supplies all or a portion of natural gas to approximately 35,000 customers in these cities.

On page 20, FEI states:

> Without the Pattullo Gas Line, the area shaded in red in Figure 3-4 would have inadequate gas supply. This represents the distribution area supplied by one regulating district station in southwest Coquitlam and two regulating district stations in New Westminster, all of which are fed from the 700 kPa trunk distribution system. Based on FEI's 2020 peak demand projection, during the coldest days of the year when peak demand occurs, and without support from the Pattullo Gas Line, these district stations would have inadequate inlet pressure leading to a loss of gas supply.

3.1 Please provide the system capacity of the Pattullo Gas Line.

**Response:**

As illustrated in Figure 3-1 of the Application, the Pattullo Gas Line is one of four feeds into the Metro Vancouver 700 kPa trunk distribution system. When considered in isolation, the Pattullo Gas Line cannot be measured in terms of "system capacity" as there are multiple simultaneous gas supplies to this trunk distribution system. This is because the capacity (or support capability) provided by each feed is dependent on how the load within the trunk distribution system is distributed and how the supplies interact together to support the system.

To illustrate the comparative capacities of the trunk distribution system with or without the Pattullo Gas Line, FEI completed an analysis which proportionally and incrementally increased the load on all the stations in this system until the pressure dropped below levels necessary for at least one of the stations to deliver sufficient gas to downstream customers. This system condition represents the threshold beyond which customer outages would start to occur.

The results of this analysis indicate that with the Pattullo Gas Line in place, the ultimate capacity of the trunk distribution system is approximately 250,800 $m^3$/hr. This measure is the theoretical peak load that could be supplied to the stations distributed along its length. The current 2020/21 forecast peak demand of the trunk distribution system is approximately 168,800 $m^3$/hr.

The difference of 82,000 $m^3$/hr represents the excess capacity of the current system, which is available to meet growth and provide resiliency.

In summary, without the Pattullo Gas Line, the trunk distribution system capacity would be 95 percent of the current 2020/21 forecast required to serve FEI's existing customers.

3.2 Please provide the additional system capacity needed to sustain gas supply to customers in Burnaby, New Westminster and Coquitlam.

**Response:**

This response also addresses BCUC IR1 3.2.1, detailing the method and assumptions made in determining system capacity.

In order to meet the future load demands on the trunk distribution system and to retain the capacity for full resiliency established in the Metro system by the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project, FEI requires a system capacity equivalent to the current Pattullo Gas Line as described in the response to BCUC IR1 3.1.

The capability and resiliency of the trunk distribution and IP systems has evolved over many decades as the current network configuration evolved. The location of the supply into the trunk distribution system is also important as it factors into the capacity requirements. If the desired goal is to retain the full resiliency provided by the LMIPSU, a supply close to the existing Pattullo Gas Line crossing is needed. If the goal were to retain most of the LMIPSU resiliency, a supply close to Coquitlam Gate Station on the Coquitlam IP system would be acceptable.

To identify the PGR Project alternatives, FEI's System Capacity Planning (SCP) department and the Project team assessed a range of upstream (supply) tie-in locations that could be connected with a new gas line to feed the trunk distribution system. The upstream tie-in options included Surrey (near the existing Pattullo Gas Line crossing), as well as locations from the east (Cape Horn area), north (near the Coquitlam IP gas line) or west (near the Fraser IP gas line). Based on these various tie-in locations, the PGR Project team developed the alternatives identified in Table 4-1 of the Application, which all provide capacity similar to that of the existing Pattullo Gas Line.

After preliminary routing was established, FEI determined the pipe size required for each proposed alternative given the pressure available at the source, and the length of the proposed gas line route. When determining pipe size, FEI modelled the proposed alternatives to confirm that the pressure into the proposed tie-in station location would remain above the standard minimum design pressure at peak demand flow conditions for the 20-year planning period. FEI's required minimum delivery pressure into trunk distribution stations is 860 kPa, to allow sufficient differential pressures to design and operate effective and reliable district stations. For alternatives where the source was transmission pressure (Alternatives 2A, 2C, 3A, 3B and 6B), FEI selected pipe sizing based on a maximum source pressure of 2070 kPa (IP) pressure to avoid installing new TP gas lines through established urban areas. For alternatives where the source was intermediate pressure (Alternatives 6A and 6C), FEI selected pipe sizing based on the pressure available when these systems are operated at 1200 kPa. The design pressures selected for each alternative are standard IP system operating pressures for FEI and consistent with the IP pressure available at each source. Choosing IP operating pressure for the gas lines, rather than DP pressure, maximizes the available capacity for a given pipe diameter.

Finally, FEI assessed the impact of each alternative on the resiliency established by the LMIPSU Project. For alternatives which have similar tie-in locations to the existing Pattullo Gas Line (i.e. Alternatives 1, 2, and 4), the impact on resiliency is neutral because there is no change to gas flow in the upstream and downstream gas lines. Alternatives that are sourced from other areas of the Metro Vancouver system (i.e. Alternatives 3 and 6) have a negative impact on resiliency because the gas that would normally be delivered by the Pattullo Gas Line must now travel further downstream before entering the trunk distribution system. This increased flow incurs higher pressure drops in the downstream networks and consequently reduces the excess capacity of these networks. This excess capacity, which would remain intact if the Pattullo Gas Line remained in-service or Alternatives 1, 2 or 4 were feasible, is used to maintain customer gas supply in the event that another supply to the trunk distribution system is compromised. For further details regarding a compromised supply scenario, please refer to Section 3.6 of the Application.

FEI quantified the loss of capacity to support resiliency by simulating a loss of gas supply (i.e. the supply from either Coquitlam Gate or Fraser Gate is out of service) into the trunk distribution system and comparing pressures under the existing system configuration (i.e. Pattullo Gas Line in-service) to those with each alternative in place. In doing so, additional improvements to the Coquitlam or Fraser IP systems were identified. As these improvements are significant in scope and could not be constructed in the required timeframe, the impact on system resiliency was not prioritized for the PGR CPCN Application.

3.2.1 Please explain FEI’s methodology for determining the additional distribution system capacity needed, detailing all assumptions made.

**Response:**

Please refer to the response to BCUC IR1 3.2.

3.3 With reference to the statement, "without the Pattullo Gas Line, the area shaded in red in Figure 3-4 would have inadequate gas supply", please quantify and explain what is meant by "inadequate gas supply".

**Response:**

As described on page 20 of the Application, the area shaded in red in Figure 3-4 encompasses the distribution area supplied by three district stations. In absence of the Pattullo Gas Line, the inlet pressure to these stations would drop below the minimum required to provide adequate supply at temperatures colder than a 28DD (minus 10°C). At these low pressures, the stations are no longer capable of passing the volumes of gas needed to serve customers downstream. As a result, the system becomes imbalanced, with more gas being consumed than what is available in the distribution system, and the pressure drops. If this imbalance continues for a sustained period, the distribution system pressure in the area shaded in red would drop below what is required for customer appliances to operate safely.

Please also refer to the response to CEC IR1 3.7 for additional discussion of the temperature conditions triggering these low pressures and the likelihood of such conditions occurring.

3.3.1 Please explain how the inadequate supply was determined.

**Response:**

Please refer to the response to BCUC IR1 3.3.

**4.0 Reference: DISTRIBUTION SYSTEM CAPACITY PROVIDED BY THE PATTULLO GAS LINE**

**Exhibit B-1, Section 3.5, pp. 20-21**

**Demand Forecast**

On page 20 of the Application, FEI states:

> Based on FEI's 2020 peak demand projection6, during the coldest days of the year when peak demand occurs, and without support from the Pattullo Gas Line, these district stations would have inadequate inlet pressure leading to a loss of gas supply. This includes approximately 2,100 customers in Burnaby, 2,800 customers in New Westminster, and 5,800 customers in Coquitlam. This represents a disruption in service to approximately 10,700 residential, commercial, and industrial customers who rely on natural gas to provide necessary heat and hot water for their homes and businesses.
>
> [6] Peak demand conditions occur in cold winter when consumer space heating demands are highest. To design reliable distribution systems FEI projects system peak demand based on coldest weather conditions likely to occur 1 in 20 years.

On page 21 of the Application, FEI states:

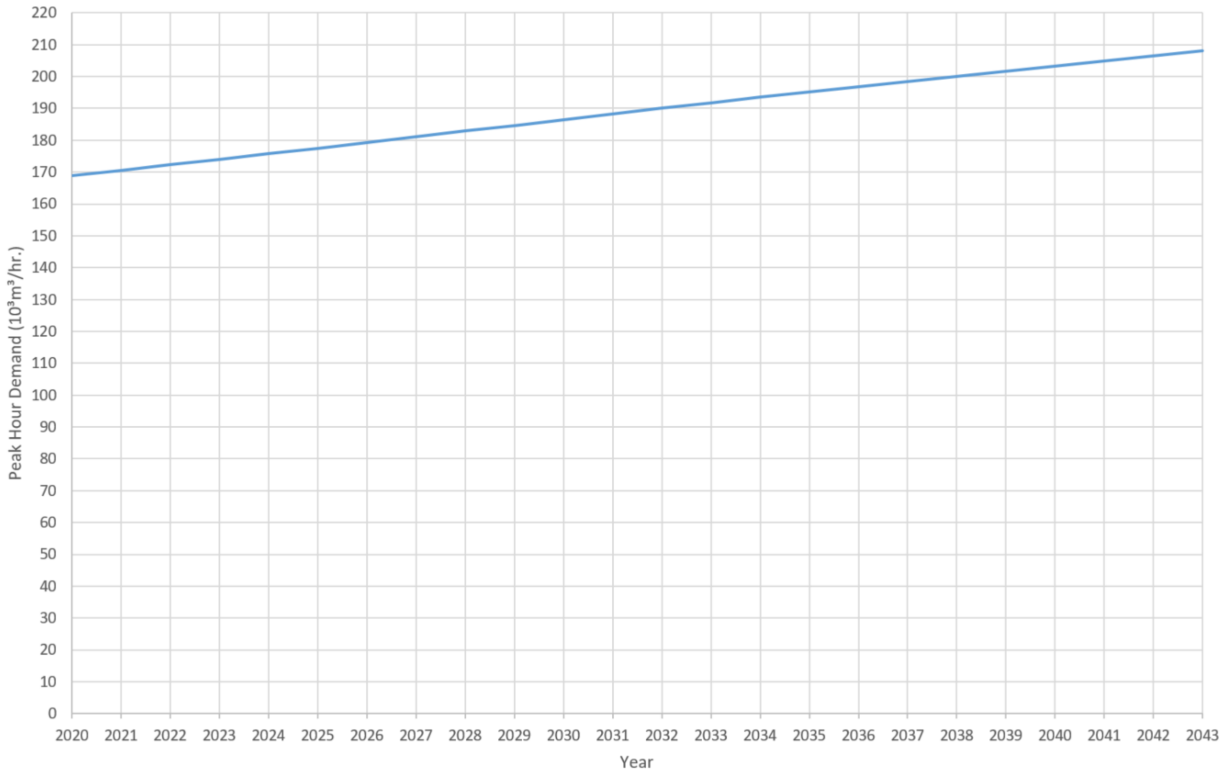
> However, without replacement of the Pattullo Gas Line, the impacted area in red would expand as customer load grows over time. Based on FEI's 20-year forecast, by 2039 an additional 14,800 customers (for a total of approximately 25,500 customers) would be without gas during cold winter periods.

4.1 Please provide FEI's 20-year demand forecast for all areas served by the Pattullo Gas Line.

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

As explained in response to BCUC IR1 4.1.1, FEI developed a 20-year <u>peak</u> demand forecast. Relevant responses provided in this series of IRs therefore refer to peak demand.

The figure below provides the 20-year peak demand forecast for the trunk distribution system served by the Pattullo Gas Line (amongst other supplies).




4.1.1 Please explain FEI's methodology for developing its 20-year demand forecast, detailing all assumptions made.

**Response:**

In developing a peak demand forecast, FEI first determined the peak demand of current customers connected to and consuming gas on the system. FEI next multiplies the average peak use per customer in various rate classes (determined as part of the first step) by the forecast number of new customer accounts in each rate schedule for each year of the forecast. This results in the forecasted peak demand for a given year. The process described is consistent with that used in previously approved CPCN applications and Long Term Gas Resource Plans and is explained in more detail below.

***Peak Demand Calculation:***

FEI determines peak hour use per customer ($UPC_{peak}$) for non-industrial customers whose consumption meters are read each month, through an annual load gather assessment (described further below). For industrial customers who have hourly metering, a recent $UPC_{peak}$ value is used to represent the maximum hourly rate of consumption measured at the customer meter. The system's current design peak demand is the sum of the customers in each rate schedule multiplied by the average $UPC_{peak}$ for each rate schedule, plus the sum of the maximum hourly demand of all industrial customers in the system. For systems with industrial customers on an interruptible rate schedule, only the contracted firm component of the customers' demand (if any) is included.

The system's future design peak demand equals the system's current design peak demand plus the sum of any forecasted incremental customer additions in each forecasted rate schedule multiplied by the average $UPC_{peak}$ for each rate schedule. No change in industrial customer numbers or demand (either firm or interruptible) are included in FEI's future peak demand estimates. Industrial demand is represented at current known levels with no change over time.

As part of the load gather assessment for customers with meters read monthly, FEI extracts each customers billing information for the preceding two-year period. With a custom software application, the customer billing information and temperature information from the local weather zone index weather stations is reduced to a daily average demand (for the customer in each billing period) and an average mean daily temperature for the corresponding billing period.

Similarly, for customers with monthly meter reads, twenty-four "daily demand" versus "mean daily temperature" data points are determined based on the customers' most recent bi-annual consumption. A linear regression for each customer is performed on this data and the base load and slope (standard $m^3$/day/degree Celsius) is calculated. The peak day demand for the customer equates to the customer's demand projected to the Design Degree Day (DDD) temperature value for the weather zone within which the customer resides.

The DDD for Metro Vancouver is a 31.2DD (mean daily temperature = minus12.2°C). The DDD peak day demand values are converted to a peak hourly demand by applying a peak hour factor (peak hour/peak daily demand)[1]. Using the hourly $UPC_{peak}$, which is calculated for each customer, FEI produces a "roll up" representing the current local regional average for each rate class.

For context, FEI calculates $UPC_{peak}$ values in sixty-six different local regions, each composed of one or more municipal districts. To smooth typical annual variances in the data, regional average $UPC_{peak}$ values for each rate schedule are averaged with the results of the preceding two years' annual load gather assessment values producing a three year "rolling average" $UPC_{peak}$ for each rate class within the region. These three-year rolling average $UPC_{peak}$ values are combined with current accounts and account addition forecasts to produce peak-hour load forecasts over a forecast period.

FEI prepares new forecasts annually, based on the newest consumption information, and does not modify the $UPC_{peak}$ values over the forecast period to account for any changes in customer consumption patterns.

[1] FEI's peak hour factor is determined from a periodic assessment of local gate station hourly and daily flow variations under winter load conditions.

4.1.2 Please describe the anticipated range of the 20-year demand forecast.

**Response:**

FEI does not calculate multiple ranges of 20-year peak demand forecasts to design its system. By convention, FEI's system demand forecasts are based on a load projection using a 1 in 20-year weather return period. In other words, there is a 95 percent certainty that the actual demand in any given year of the forecast will be at or below the forecast level.

4.2 Please explain whether FEI applied any scenario modelling to its 20-year demand forecast.

**Response:**

No, FEI did not apply any scenario modelling to its 20-year peak demand forecast. Please refer to the response to BCUC IR1 4.1.2.

4.2.1 If so, please provide details of any scenarios assessed and discuss the results with respect to FEI's assessment of the impact of removing the Pattullo Gas Line.

**Response:**

Please refer to the response to BCUC IR1 4.2.

4.3 Please clarify whether FEI's forecast of disrupted service to approximately 10,700 residential, commercial and industrial customers is based on FEI's forecast demand for the year 2020 or whether it is based on forecast peak demand conditions (as defined in the preamble above).

**Response:**

FEI's forecast of disrupted service is based on forecast peak demand that could occur in the year 2020. For clarification, the preambles' reference to 1 in 20 years (Footnote 6) is not a forecast period, but rather, refers to the likelihood of the design temperature (extreme cold temperature) occurring in any year.

4.3.1 If the former, please explain why FEI used the 2020 forecast demand.

**Response:**

FEI used the forecast peak demand that could occur in the year 2020 to illustrate that if the Pattullo Gas Line's system capacity is not replaced, customer supply disruptions could occur in 2020, impacting approximately 10,700 existing customers in Burnaby, New Westminster and Coquitlam.

As described in FEI response to BCUC IR 1.4.1, the forecasted peak demand increases annually, potentially impacting an additional 14,800 customers by 2039.

4.3.2 If the former, please provide the number of customers that would experience disrupted service if the forecast demand for the year 2023 was used.

**Response:**

In 2023, roughly the same numbers of customers in the same region of the system would be impacted if the Pattullo Gas Line's system capacity is not replaced, as the same three district stations (as referenced in the response to BCUC IR1 3.3) be impacted.

4.4 Please discuss whether FEI uses peak day or peak hour demand as a design basis for its distribution systems and explain the reasons for this design basis.

**Response:**

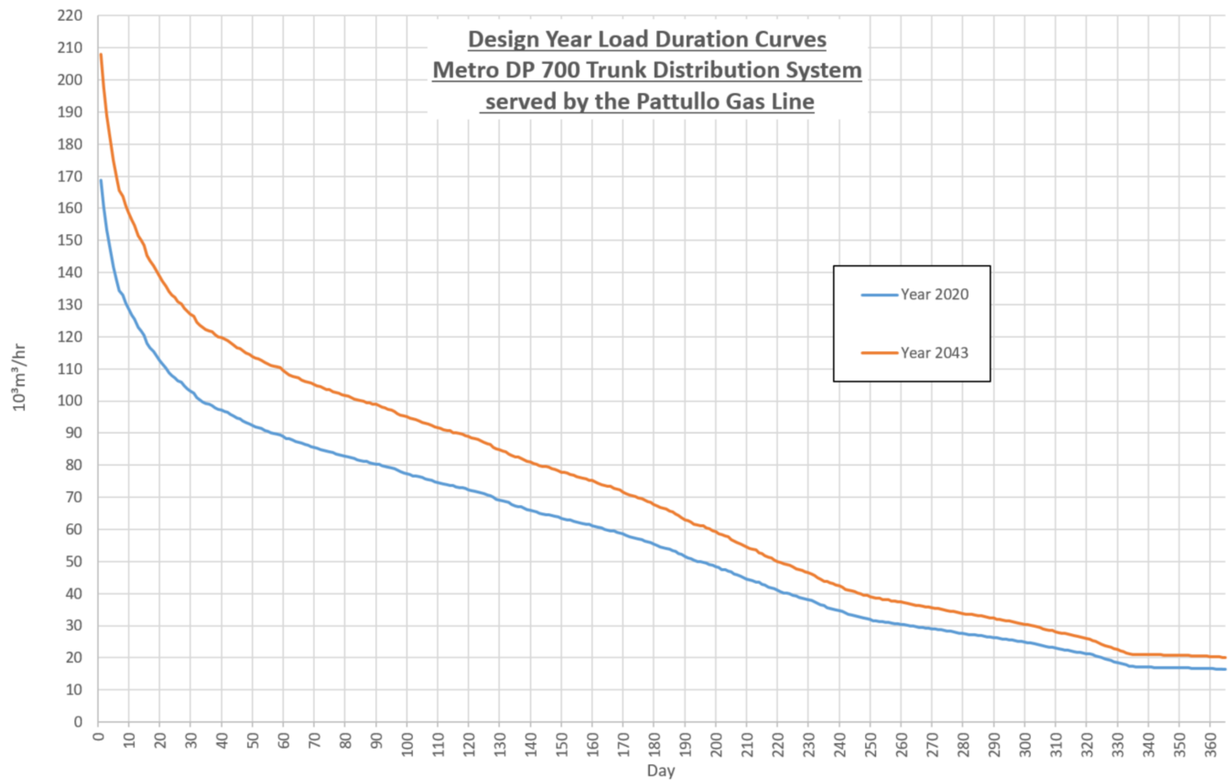
FEI uses peak hour demand as the design basis for its distribution systems.

Designing on a peak hour demand basis means that gas mains and services are designed to have sufficient capacity to meet customer demand on the system under the highest hourly flow expected on a peak day. FEI's distribution system demand in winter varies significantly from hour to hour throughout a given day. The highest hourly flow of the day can be 25 to 40 percent higher than the average hourly flow for the same day. This daily variation in demand is due to the heat sensitive nature of loads such as space heating and the daily vairiability in consumption patterns of residential and commercial gas consumers.

4.5 Please provide Load Duration Curves for the distribution system supplied by the Pattullo Gas Line now and at the end of the 20-year planning period, which shows the peak demand for each day of a design year.

**Response:**

The figure below shows Design Year Load Duration Curves for the trunk distribution system for each day of 2020 (the design year) and 2043.




4.6 Please provide a table summarizing the following: the annual forecast demand under peak demand conditions from 2023 to 2043, the available capacity with the Pattullo Gas Line, the available capacity without the Pattullo Gas Line and the number of customers that would experience service disruptions.

**Response:**

Since peak demand is not a condition sustained through an annual cycle, FEI assumes that by referring to "annual forecast demand under peak demand conditions" the BCUC is asking for the peak demand forecast for the trunk distribution system served by the Pattullo Gas Line in tabular form (previously provided in graphical form in the response to BCUC IR1 4.1). Please refer to the table below.

| Year | Peak Demand ($10^3m^3/hr$) | Capacity of the Trunk Distribution System with the Pattullo Gas Line ($10^3m^3/hr$) | Capacity of the Trunk Distribution System without the Pattullo Gas Line ($10^3m^3/hr$) | Customers at risk of outage |
|---|---|---|---|---|
| 2023 | 174.0 | 250.8 | 160 | Up to 10,700 |
| 2024 | 175.7 | 250.8 | 160 | |
| 2025 | 177.4 | 250.8 | 160 | |
| 2026 | 179.2 | 250.8 | 160 | |
| 2027 | 181.0 | 250.8 | 160 | |
| 2028 | 182.9 | 250.8 | 160 | 10,700 to 18,000 |
| 2029 | 184.7 | 250.8 | 160 | |
| 2030 | 186.5 | 250.8 | 160 | |
| 2031 | 188.2 | 250.8 | 160 | |
| 2032 | 190.0 | 250.8 | 160 | 18,000 to 25,500 |
| 2033 | 191.8 | 250.8 | 160 | |
| 2034 | 193.5 | 250.8 | 160 | 25,500 to 32,500 |
| 2035 | 195.2 | 250.8 | 160 | |
| 2036 | 196.9 | 250.8 | 160 | |
| 2037 | 198.5 | 250.8 | 160 | |
| 2038 | 200.1 | 250.8 | 160 | |
| 2039 | 201.7 | 250.8 | 160 | |
| 2040 | 203.3 | 250.8 | 160 | |
| 2041 | 204.8 | 250.8 | 160 | |
| 2042 | 206.4 | 250.8 | 160 | |
| 2043 | 208.0 | 250.8 | 160 | |

4.7 Please explain whether FEI supplies customers, in any areas served by the Pattullo Gas Line, under an interruptible service rate.

4.7.1 If so, please explain whether FEI has accounted for these customer's demand in its demand forecast.

4.7.1.1 If not, please explain why not.

**Response:**

Yes, there are customers in the area served by the Pattullo Gas Line with an interruptible service rate schedule, including one customer served under Rate Schedule 7 and two customers served under Rate Schedule 27. These customers are not represented in FEI's 20-year peak demand forecast as they are expected to be curtailed under peak demand conditions. FEI's distribution and transmission systems are designed to accommodate peak demand of firm rate schedule customers only. Interruptible service rate schedules are served under demand conditions when capacity exceeds the needs of firm customers.

4.7.1.2 Please update the demand forecast provided in response to Information Request (IR)4.6 to show demand from firm and interruptible rate customers.

**Response:**

The load for customers on interruptible rate schedules is assumed to be curtailed and not present on the system under peak demand. As a result, the table provided in the response to BCUC IR1 4.6 would remain unchanged.

**5.0 Reference: SIGNIFICANCE OF THE PATTULLO GAS LINE TO THE METRO VANCOUVER DISTRIBUTION SYSTEM**

**Exhibit B-1, Section 3.3, p. 16; Section 3.7, p. 22.**

**Resiliency**

On page 16 of the Application, FEI states:

> Although it is relatively short in length (as shown in Figure 3-1), the Pattullo Gas Line is a critical link in the gas supply to thousands of downstream customers. Specifically, it provides two key benefits:
>
> 1. Distribution system capacity to supply natural gas to customers in Burnaby, New Westminster and Coquitlam; and
> 2. Resiliency to FEI's larger Metro Vancouver area.

On page 22 of the Application, FEI states:

> FEI has determined that it cannot replace the distribution system resiliency benefits of the Pattullo Gas Line at this time. Therefore, another project or system improvements will be undertaken to restore the Metro Vancouver system resiliency at a later date.

5.1 Please describe the system resiliency as it relates to this Application and how it is measured.

**Response:**

FEI defines resiliency as the ability to prevent, withstand and recover from system failures or unforeseen events. Resiliency is directly linked to the concept of reliability in the sense that a system cannot be resilient without first having reliable components. However, resiliency also encompasses concepts such as preparing for, operating through, and recovering from significant disruptions, no matter the cause.

Resiliency as it relates to this Application is the ability to operate through a major supply disruption to or from one of the two major gate stations serving the Metro Vancouver area (i.e., Fraser Gate or Coquitlam Gate station). The capacity to withstand such a disruption was added through two recent major system upgrade projects in the Lower Mainland, as follows:

- The Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project has enhanced the capacity in the Metro Vancouver system, such that even under peak conditions all customers served by the system can continue to be supplied during a complete loss of supply from either the Fraser Gate or Coquitlam Gate station.

- The Coastal Transmission System (CTS) Project (completed in 2016) added three transmission line loops in the CTS and provided the transmission capacity to shift the forecast peak load between Coquitlam Gate and Fraser Gate stations.

With the removal of the Pattullo Gas Line, shifting the load served by that gas line onto the transmission pipelines that feed Coquitlam Gate or Fraser Gate station increases the pressure drop on those gas lines and will erode available surplus capacity. Similarly, when the demand currently served by the Pattullo Gas Line passes through Fraser Gate or Coquitlam Gate into the downstream IP Gas Lines, the additional flow will erode excess available capacity on those stations and gas lines. The excess capacity in these systems would otherwise be available to accommodate future growth in demand and respond to a system disruption.

Resiliency itself is generally not measured directly, but in this instance the capacity to avoid a supply disruption can be measured. Each of the Project alternatives can be compared by measuring the capability to withstand a gate station supply disruption. That capability is measured by comparing the number of Degree Days[2] (DD) during which minimum delivery pressures at district stations in the various Metro Vancouver systems can still be maintained when supply disruptions impact the Fraser Gate and Coquitlam Gate stations. A system configuration that supports the ability to shift load on a greater DD (i.e., days with colder temperature) has the capacity to be a more resilient system. The outcome of this calculation is explored further in the response to BCUC IR1 5.3.

5.2 Please explain the criteria that FEI uses to determine an acceptable level of system resiliency in the Metro Vancouver area.

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

FEI does not have an explicit criteria for acceptable system resiliency in the Metro Vancouver area, but FEI considers that with the Pattullo Gas Line in its current position and the completion of the LMIPSU and CTS projects, the resiliency of the Metro Vancouver system has achieved an appropriate level for this large urban area. Please refer to the response to BCUC IR1 5.1 for an explanation of how FEI assesses available capacity to respond resiliently to system disruptions in the Metro Vancouver area.

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[2] A Degree Day is a temperature based measure that increases as mean daily temperature decreases and demand for heating increases. FEI uses a Degree Day metric based on 18C. The formula for a Degree Day(DD) is:

$DD = 18^{o}\ C - T_{avg}$

e.g., The DD for a mean daily temperature of -2º C is : 18º C - (-2º C) = 20 DD

5.3 Please elaborate on the resiliency benefit that the Pattullo Gas Line provides to the Metro Vancouver area and quantify the benefit.

**Response:**

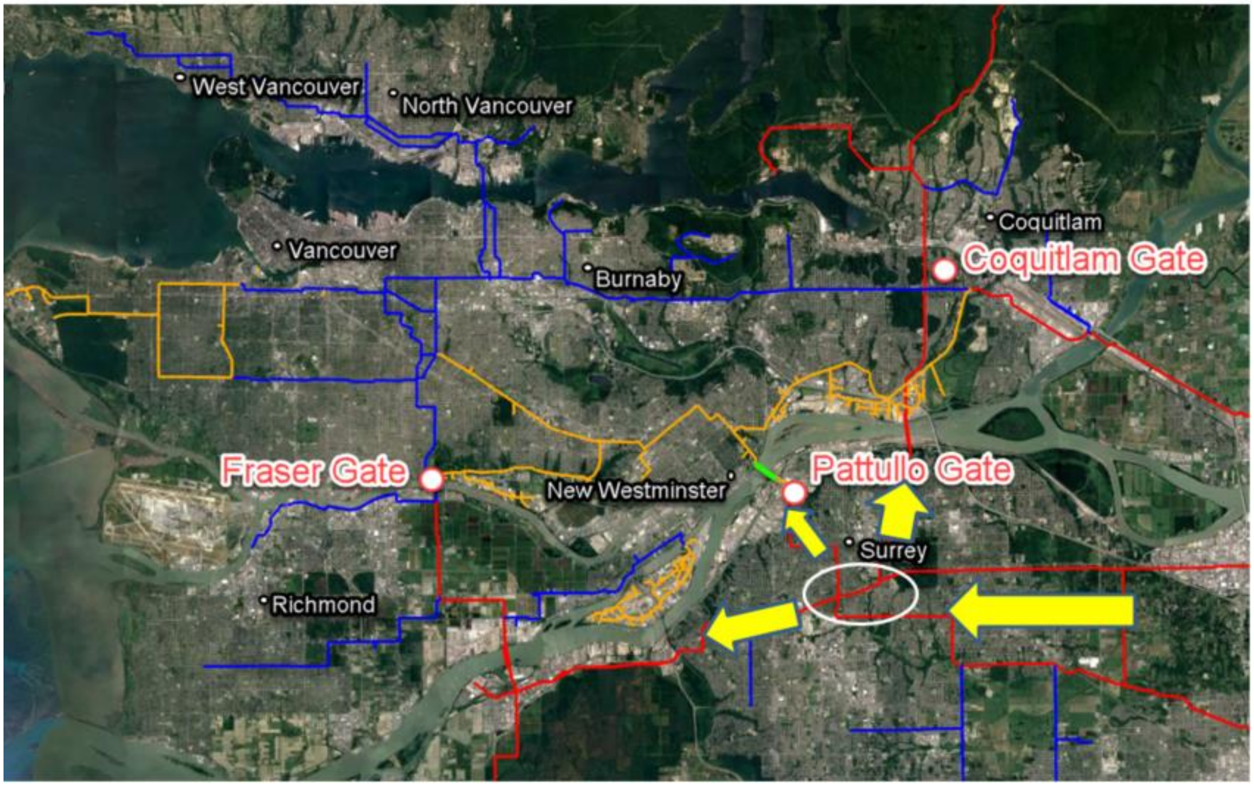
FEI provides below a qualitative and quantitative description of the resiliency benefit provided by the Pattullo Gas Line.

**Qualitative description of the Pattullo Gas Line Resiliency Benefit**

The resiliency benefit provided by the Pattullo Gas Line results from the fact that it is one of three supply sources for the Metro Vancouver area, and is supplied independently from the other two major sources. All of the gas supply to Vancouver, Burnaby, New Westminster, the North Shore, and part of Coquitlam flows through three FEI gate stations: Fraser Gate, Coquitlam Gate, and Pattullo Gate (as shown in the figure below). The system downstream of these three gate stations is interconnected; consequently, the total demand in these municipalities is shared by these three supply points. As described in the response the BCUC IR1 5.1, with the completion of the LMIPSU project, even if the gas supply is totally disrupted at Fraser Gate or Coquitlam Gate, it is still possible to meet the forecast peak demand in the area using the supply from the remaining two gate stations.

By supporting customers on the trunk distribution system, the Pattullo Gas Line allows the excess capacity in the Metro IP system (and the upstream transmission system feeding those stations) to support the remaining customers on the Metro IP system under peak demand conditions through either Fraser Gate or Coquitlam Gate. It is this excess capacity retained in the Metro IP system because of the Pattullo supply that supports resiliency for the Metro Vancouver area. Even in the event of an unforeseen major disruption at one of the two gate stations or the upstream transmission supply, it is still possible to meet the customer peak demand.

Figure 1




Once the existing Pattullo Gas Line is removed from service when the Pattullo Bridge is demolished, there will no longer be three sources of supply into Metro Vancouver: only the Fraser Gate and Coquitlam Gate supplies will remain. While these two stations when combined do have some capacity in excess of the forecast peak demand, it will be significantly reduced compared to the present day configuration.

**Quantitative description of the Pattullo Gas Line Resiliency Benefit**

In order to quantify the resiliency benefit provided by the Pattullo Gas Line, FEI conducted an analysis comparing the current system, and that of Alternatives 6A and 6B. Two timeframes were modelled in the analysis: winter 2023-24 and winter 2034-35. The results of this analysis are shown in Table 1 and explained further below.

**Table 1: Metro System Resiliency Comparison**

| Alternative | Degree Day where LMIPSU Resiliency is Achieved | | | |
|---|---|---|---|---|
| | Winter 2023-24 | | Winter 2034-35 | |
| | With Interrupt. Curtailed | With Interrupt. On | With Interrupt. Curtailed | With Interrupt. On |
| 6A or 6B | 26.5DD (-8.5 C) | 23DD (-5 C) | 24.5DD (-6.5 C) | 21.5DD (-3.5 C) |
| Existing Pattullo Gas Line | OK to Design Conditions 30.2DD (-12.2 C) | OK to normal Interruptible DD 24.3DD (-6.3 C) | 29DD (-11 C) | OK to normal Interruptible DD 24.3DD (-6.3 C) |

**Winter 2023-24 Analysis Results**

With the Pattullo Gas Line in operation during the winter of 2023-24, the Metro Vancouver system exhibits full resiliency up to FEI's 30.2DD design day conditions, as noted by the cell in Table 1 with the comment "OK to Design Conditions 30.2DD (-12.2 C)".

For Alternatives 6A or 6B (i.e. the Pattullo Gas Line is no longer in service), during the same winter, resiliency can only be maintained up to 26.5DD day conditions, as noted by the cell in Table 1 with the comment "26.5DD (-8.5 C)". This reduced resiliency creates an outage risk to tens of thousands of customers in the Metro Vancouver Area during the coldest winter days between minus 8.5 C and minus 12.2 C simply because the Pattullo Gas Line is no longer available to provide additional supply into the area.

**Winter 2034-35 Analysis Results**

The analysis in Table 1 also shows that the resiliency of the Metro Vancouver system degrades over time in all cases, and especially so for Alternatives 6A and 6B.

With the Pattullo Gas line in operation during the winter of 2034-35, the Metro Vancouver system exhibits resiliency only up to a 29 DD (-11 C), as noted by the cell in Table 1 with the comment "29DD (-11 C)". Although this weather scenario is slightly warmer than full design day conditions, there is still some risk of outage for several thousand customers.

For Alternatives 6A or 6B (i.e. the Pattullo Gas Line is no longer in service), during the same winter, resiliency can only be maintained up to 24.5DD day conditions, as noted by the cell in Table 1 with the comment "24.5DD (-6.5 C)". This resiliency point is a full 2 °C warmer compared to the winter of 2023-24 and will create a risk of outages for even more customers.

**Conclusion**

In summary, the resiliency benefit provided by the Pattullo Gas line results from it being a third and independent supply of gas into the Metro Vancouver system. This gas line has provided the benefit of enabling FEI to meet 100 percent of the forecast firm gas demand during design day conditions in the Metro Vancouver area, even if gas supply from one of the other two sources (Fraser Gate or Coquitlam Gate) was fully interrupted.

5.3.1 Please discuss the risks to FEI's system associated with not having the resiliency benefit of the Pattullo Gas Line in place.

**Response:**

Please refer to the response to BCUC IR1 5.3.

5.3.2 Please discuss and quantify the impact that losing the resiliency provided by the Pattullo Gas Line will have on the resiliency of FEI's system in the Metro Vancouver area.

**Response:**

Please refer to the response to BCUC IR1 5.3.

5.4 Please provide FEI's target date for completing another project or system improvements to restore the Metro Vancouver system resiliency.

**Response:**

FEI is continuing to evaluate alternatives to restore system resiliency in the Metro Vancouver area which is currently provided by the LMIPSU Project. Until the scope of the Project is better defined, FEI is unable to provide additional information about any follow-up project(s) to restore resiliency at this time, including project overview, timing, or anticipated cost.

However, given the likely scope, it is expected that any resulting project will exceed the current CPCN threshold, and that FEI will be required to file a separate CPCN application with the BCUC.

5.4.1 Does FEI anticipate filing an application with the BCUC for approval to undertake the resiliency project or system improvement?

**Response:**

Please refer to the response to BCUC IR1 5.4.

5.5 Please provide details of any resiliency projects or system improvements currently being considered by FEI, including project overview, timing and anticipated cost.

**Response:**

Please refer to the response to BCUC IR1 5.4.

5.6 Please explain whether the alternative selected to complete the PGR Project will impact the feasible alternatives for the resiliency project or system improvements

**Response:**

Please refer to the response to BCUC IR1 5.4.

# B. ALTERNATIVES EVALUATION

## 6.0 Reference: OVERVIEW OF ALTERNATIVES ANALYSIS

**Exhibit B-1, Section 4.2, Table 4-1, p. 24**

**Alternatives Considered for PGR Project**

On page 24, FEI provides the following table listing the six alternatives and the sub-alternatives it considered for the PGR Project.

**Table 4-1: Alternatives and Sub-Alternatives Considered for PGR Project**

| Alternatives and Sub-Alternatives Considered | |
|---|---|
| **Alternative 1** | **Attachment to the New Bridge** |
| **Alternative 2** | **Trenchless Crossing of the Fraser River**<br>• Alternative 2A - High Pressure Horizontal Directional Drill (TP/IP HDD)<br>• Alternative 2B - Distribution Pressure Horizontal Directional Drill (DP HDD)<br>• Alternative 2C - Alternate High Pressure Horizontal Directional Drill (TP/IP)<br>• Alternative 2D - Other Trenchless Methodologies (Micro-tunneling) |
| **Alternative 3** | **Through Richmond with Fraser River Crossing**<br>• Alternative 3A - TP Gas Line with 1 Gate Station<br>• Alternative 3B - IP Gas Line with 1 Gate Station and 1 District Station |
| **Alternative 4** | **Aerial Gas Line Crossing** |
| **Alternative 5** | **Peak Shaving Facility / Virtual Gas Line**<br>• Alternative 5A - Liquefied Natural Gas (LNG)<br>• Alternative 5B - Compressed Natural Gas (CNG) |
| **Alternative 6** | **Overland Gas Line**<br>• Alternative 6A - Broadway and Gaglardi Way Corridor<br>• Alternative 6B - Cape Horn Gate Corridor<br>• Alternative 6C - Fraser Gate Corridor<br>• Alternative 6D – Sperling Avenue Corridor |

6.1 Please explain whether FEI considered upgrading the existing trunk distribution system to increase the system capacity, including potential loop lines paralleling the existing system mains.

6.1.1 If not, please explain why not.

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

6.1.3 If yes, please discuss whether FEI considered any alternative that included such upgrading of the existing trunk distribution system and why they were not pursued.

**Response:**

FEI considered the alternative of upgrading the existing trunk distribution system but determined that the alternative was not preferred as it would further degrade the resiliency of the DP and IP systems.

There are two potential upgrade/looping options: (1) the addition of loop lines or increasing the diameter of the trunk from the Coquitlam source at Como Lake and Westwood Station stations; and (2) a looping project from Fraser Gate station.

However, these options are likely to cost more than a replacement supply option in the Burnaby/New Westminster area. The addition of loop lines or increasing the diameter of the trunk from the Coquitlam source at Como Lake and Westwood stations would require a project scope of approximately 12 km in length (approximately twice the length of FEI's preferred option). A looping project or replacement project from Fraser Gate station is similar in scope to what is provided in Alternative 6C. Resiliency for such options would be further reduced if the system's operating pressure were to remain at 700 kPa rather than increased to IP pressure, unless the pipe size was increased to compensate for the lower pressure.

Neither of these options would provide a replacement of the Pattullo Gas Line supply, making the system more vulnerable and less resilient to supply disruption events. Given that the resiliency of the system would already be degraded from the loss of the Pattullo Gas Line, FEI considers that further degradation of the resiliency of the system would not be prudent.

FEI focused on replacement supply into the distribution system in the Burnaby/New Westminster area because the resiliency of the DP and IP system would be degraded to a lesser extent than with the above-noted distribution looping options. As such, all alternatives considered included a replacement supply of natural gas for the trunk distribution system.

**7.0 Reference: EVALUATION OF TRENCHLESS CROSSING OF THE FRASER RIVER**

**Exhibit B-1, Section 4.3.2, p.29**

**Technical Assessment**

On page 29, FEI states:

> FEI evaluated several options for a trenchless crossing of the Fraser River near the Pattullo Bridge, including three horizontal directional drill (HDD) alignments and other trenchless crossing methods. FEI engaged a drilling contractor as part of an early contractor involvement project delivery method to further assess these alternatives. All of the proposed sub alternatives were identified as not being constructible and had other technical issues and risks which could not be adequately addressed or cost effectively mitigated using risk mitigation techniques. As a result, FEI determined that these alternatives were not feasible.

7.1 Please describe the early contractor involvement process and associated time frame for contractor involvement in assessing the alternatives.

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

FEI worked with an advisor (Bramcon Project Consultants Ltd.) to develop the Project's implementation strategy and determined that a project delivery method (PDM) incorporating early contractor involvement would optimize project results by integrating the Design-Builder into the early stages of the project development. The PDM selected for the HDD scope of work was progressive design build (PDB), in which FEI contracts directly with one firm, the Design-Builder, to deliver the project in two distinct phases. Phase 1 includes design development, pre-construction services, relying on early contractor input, along with negotiation of commercial terms. Once the projects design aligns with FEI's requirements, the Design-Builder provides a formal commercial proposal and fixed price for completion of the construction under Phase 2.

FEI entered into a PDB contract with Peter Kiewit Sons ULC (together with designers Mott MacDonald for their HDD expertise and Thurber Engineering Ltd for their geotechnical expertise) from June 2019 to October 2019, at which time the proposed HDD alignments and other trenchless crossing methods were determined to be not feasible.

7.2 Please elaborate on the drilling contractor's relevant qualifications and experience.

**Response:**

The relevant qualifications and experience of the drilling contractor, Peter Kiewit Sons ULC (teamed with designers Mott MacDonald for their HDD expertise and Thurber Engineering Ltd. for their geotechnical expertise) are as follows:

Peter Kiewit Sons ULC (Kiewit) is an experienced and competent multi-disciplinary design-build contractor with expertise in trenchless construction and engineering design with relevant qualifications and experience that include the following projects:

- Trans Mountain Expansion Project-Langley to Burnaby, BC (twinning of an existing pipeline): Design-builder for 35.5 kilometres of an NPS 36 pipeline including a Fraser River submarine crossing, a new dock complex with three marine berths at Westridge Marine, mainline piping and manifold at Sumas Terminals and a 2.6 kilometre, 4.3 metre diameter tunnel from Burnaby Terminal to Westridge Marine.
- Various power interconnection infrastructure projects for EPCOR Industrial Infrastructure L.P. in various locations for electric power supply for the pump stations and terminal on the Trans Mountain Expansion Project: Design, Build, Own, Operate and Transfer agreement for 7 substations, 11 switchyards, 3 transmission line and 55 remote main line block valves.

For more information, refer to https://www.kiewit.com/.

Kiewit teamed with designer Mott MacDonald, a leading engineering, management and development consultancy. Mott MacDonald was ranked as the number two top trenchless design firm in North America in 2018 by Engineering News-Record and is industry recognized as having the skill, experience, and ability to take on challenging projects that require a trenchless design solution. Mott MacDonald's relevant qualifications and experience include providing trenchless engineering services for the following projects:

- Trans Mountain Expansion Project-Hope to Burnaby, B.C.: 25 major trenchless crossings including 7 HDD crossings and a 2.6 kilometre, 4.3 metre diameter tunnel from Burnaby Terminal to Westridge Marine.
- Oakland Inner Harbor Crossing: a 915 metre, NPS 24 HDD crossing of the Oakland Inner Harbor estuary in an urban setting.
- Energy East Pipeline Project: Crossing feasibility assessments for 3 river crossings including the Riviere du Nord, Riviere des Outaouais and Riviere Etchemin Lateral.

For more information, refer to https://www.mottmac.com/.

Mott MacDonald teamed with Thurber Engineering Ltd. to provide a complete range of geotechnical services including site investigations and stability analyses. They offer specialized knowledge and experience particular to the Lower Mainland in earthquake geotechnique, geohazards, tunneling and trenchless technologies. Thurber Engineering's relevant qualifications and experience include the following projects:

- Annacis Water Supply Tunnel: a 2.3 kilometre, 3.66 metre tunnel between the City of New Westminster and the City of Surrey.

For more information, refer to https://thurber.ca/.

Collectively, the teams as referenced above, completed the following projects within the last 10 years:

- Port Mann/Highway 1 Improvement: Improvements to a 37 kilometre section of highway 1 between the Township of Langley and the City of Vancouver including 17 interchanges, 28 overpass and underpass structures and construction of a 2 kilometre cable-stayed bridge over the Fraser River between the City of Surrey and the City of Coquitlam.
- WAC Bennett Dam Riprap Upgrade: Dam improvements including replacement of existing rock with larger, durable limestone.
- Portland East Side Combined Sewer Overflow: A 8.9 kilometre, 6.7 metre ID tunnel including 7 large diameter shafts and 3.2 kilometres of shallow pipelines, microtunnels and diversion structures.
- CN Rail Pier 11 Seismic Retrofit: Installation of two 2 metre diameter, 80 metre deep pipe piles with rebar cages and concrete placed inside, 80 MT beams with post tensioned bars and saw cutting the existing pier.

7.3 Please explain whether FEI engaged an independent engineering firm to assess the feasibility of the trenchless crossing alternatives.

7.3.1 If confirmed, please describe the engineering firm's relevant qualifications and experience. Please also provide the independent engineer's scope of work on this project.

7.3.2 If not, please explain why not.

**Response:**

Yes, FEI engaged McMillen Jacobs Associates (MJA) and Golder Associates Corp. (Golder) as independent engineering firms to review and validate all deliverables provided by Kiewit.

MJA has extensive trenchless crossing design and construction experience. They maintain over 430 technical staff with specialization in geotechnical, trenchless and tunnel engineering capabilities. In the last ten years, MJA's technical staff has worked on more than 100 geotechnical pipeline, trenchless/tunneling and seismic resiliency projects for power, natural gas, water and wastewater, and other utility agencies.

MJA's scope of work included:

(1) Review of documentation provided by Kiewit, including but not limited to:
   (a) Reports;
   (b) Specifications;
   (c) Datasheets;
   (d) Calculations;
   (e) Drawings;
   (f) Memorandums;
   (g) Decision Records; and
   (h) any other technical documents provided by FEI.

(2) Attend meetings as requested by FEI;

(3) Provide technical advice to FEI on matters related to trenchless design and construction;

(4) Review cost estimates and associated documentation and provide advice to FEI on content and methodology;

(5) Provide advice to FEI regarding the constructability of designs proposed by Kiewit; and

(6) Provide advice to FEI on the structure and content of construction contracts if requested.

Golder is one of the largest and most experienced companies providing geotechnical services in British Columbia. They have local expertise in seismic evaluation and design, soft ground engineering, deep foundations, and trenchless and tunneling engineering. Their portfolio includes geotechnical support of many trenchless installations for local power, natural gas, water and wastewater, and other utility agencies, exhibiting similar conditions faced by the Project's HDD alternatives.

Golder's scope of work included the following:

(1) Review of documentation provided by Kiewit, including but not limited to:
   (a) Reports;
   (b) Specifications;
   (c) Datasheets;

(d) Calculations;

(e) Drawings;

(f) Memorandums;

(g) Decision Records; and

(h) any other technical documents provided by FEI.

(2) Attend meetings as requested by FEI;

(3) Provide technical advice to FEI on matters related to the geotechnical conditions for trenchless design and construction;

(4) Review cost estimates and associated documentation and provide advice to FEI on content and methodology; and

(5) Provide advice to FEI regarding the constructability of designs proposed by Kiewit.

7.4 Please describe any assessments to determine the feasibility of the trenchless crossing alternatives, including engineering, geological and geotechnical studies and provide the results of these assessments.

**Response:**

Included as Attachment 7.4 are the engineering, geological and geotechnical studies and assessments completed by the drilling contractor.[3] The documents included are as follows:

| Document # | Title | Discipline | Results |
|---|---|---|---|
| P-00758-PIP-MEM-0001 | Pre-FEED HDD Alignment Route Evaluation | Engineering | Not feasible |
| P-00758-PIP-MEM-0002 | Proposed Alternative HDD Alignment Memo | Engineering | Technically feasible |
| P-00758-PIP-MEM-0005 | Microtunnel Feasibility Memo | Engineering | Not feasible |
| P-00758-GEO-MEM-0001 | Preliminary Flow Failure Assessment Memo | Geotechnical | Supporting data |

[3] Refer to the response to BCUC IR1 7.2 for the drilling contractor's relevant qualifications and experience.

1 Additional geotechnical reports supplied by others were as follows:

| Document # | Title | Discipline | Results |
|---|---|---|---|
| | PBR 2018-07 Phase A Geotechnical Site Investigation Report - Golder[4] | Geotechnical | Supporting data |
| | PBR 2018-07 Phase B Land Geotechnical Site Investigation Report - Golder | Geotechnical | Supporting data |

2

[4] Refer to the response to BCUC IR1 7.3.1 for Golder's relevant qualifications and experience.

**8.0 Reference: EVALUATION OF ALTERNATIVES 6A, 6B AND 6C**

**Exhibit B-1, Section 4.4.2, pp. 40-42**

**Pipeline Design**

On page 40, FEI states, "the Broadway and Gaglardi Way Corridor option involves the installation of approximately 5 km of NPS 20 (508 mm) IP gas line in the City of Burnaby."

On page 41, FEI states, "the Cape Horn Gate Corridor option involves the installation of approximately 8 km of NPS 20 IP gas line in the Cities of Coquitlam and Burnaby."

On page 42, FEI states, "the Fraser Gate Corridor option involves the installation of approximately 7 km of NPS 20 (508 mm) IP gas line starting at Fraser Gate Station in the City of Vancouver."

8.1 Please provide the design capacity of the pipeline for each of these alternatives.

**Response:**

In order to provide a meaningful representation of the existing Pattullo Gas Line's contribution to the trunk distribution system's capacity, FEI has used the same methodology as in the response to BCUC IR1 3.1, which describes the current system capacity with the existing Pattullo Gas Line. For each alternative, FEI conducted an analysis whereby the load on all the stations in the trunk distribution system was proportionally increased until the pressure dropped below that necessary for at least one of the stations to deliver the gas required to supply downstream customers. The table below summarizes the contribution to system capacity of each of the 3 alternatives applying the method described above.

Alternative 6A and Alternative 6B are expected to deliver gas to the same location on the existing trunk distribution system, in the vicinity of 10th Avenue and McBride Boulevard. The available capacity they provide to the system is therefore similar by providing about 20,000 $m^3$/hr more delivery capacity to the trunk distribution system than the existing Pattullo Gas Line. Alternative 6C provides about 19,000 $m^3$/hr less capacity than the current Pattullo Gas Line. The table below provides the trunk distribution system capacity for each of these alternatives.

**Table 1: Comparison of System Capacities for Alternatives**

| Description | System Capacity of Alternative ($m^3$/hr) |
|---|---|
| Alternative 6A - Broadway and Gaglardi Way Corridor | 275,000 |
| Alternative 6B - Cape Horn Gate Corridor | 275,000 |
| Alternative 6C - Fraser Gate Corridor | 222,000 |

8.1.1 Please explain FEI's methodology for determining the design capacity, detailing all assumptions made.

**Response:**

Please refer to the response to BCUC IR1 8.1.

8.1.2 Please also elaborate on the difference in design capacity between alternatives, if any.

**Response:**

Please refer to the response to BCUC IR1 8.1.

8.2 Please describe the conceptual design for these alternatives in more detail, including the construction method(s) to be used as well as any design parameters that FEI used in its evaluation.

**Response:**

Each Project alternative requires the design, construction and operation of an urban pipeline.

The conceptual design phase included completing preliminary routing from known start and end locations, based on existing infrastructure. Natural features, as well as existing and planned manmade constraints to routing, were identified.

Construction methods considered for each alternative included standard urban pipeline construction techniques developed and proven successful on FEI's previous LMIPSU and CTS projects, including stove pipe and drag section installation. Trenchless construction methods were considered for crossings of major waterways, railways and major roadways.

The design parameters for each alternative included:

| Property | Value |
|---|---|
| Pipe Size | 508 mm (NPS 20) |
| Design Flow Rate | 102,000 m³/hr |
| Maximum Operating Pressure (MOP) | 2070 kPa (300 psi) |
| CSA notch toughness requirement | Category II |
| Material Grade | 290 MPa regular pipe, 359 MPa for HDD |
| Design Factor | 0.80 (pipeline) |
| Location Factor | 0.50 (general) Assuming Class Location 4 |
| Joint Factor | 1.00 |
| Temperature Factor | 1.00 |
| Minimum Depth of Cover | 1.2 m |
| Minimum Design Temperature | minus 5 degC |
| Maximum Design Temperature | 54 degC |
| Minimum Installation Temperature | minus 5 degC |
| Service | Natural Gas – sweet, odourized |
| Pipeline Design Standard | CSA Z662-19 |
| Line Pipe Design Standard | CSA Z245.1-18 |

8.3 Please explain how FEI determined the pipe diameter and design pressure for these alternatives.

**Response:**

Please refer to the response to BCUC IR1 3.2.

**9.0 Reference: EVALUATION OF ALTERNATIVES 6A, 6B AND 6C**

**Exhibit B-1, Section 3.2, p.14; Exhibit B-1, Section 4.4.2, pp. 40-42**

**Intermediate Pressure Pipeline**

On page 14, FEI states that the Pattullo Gas Line is a nominal pipe size (NPS) 20 distribution pressure (DP) pipeline.

On page 40, FEI states, "the Broadway and Gaglardi Way Corridor option involves the installation of approximately 5 km of NPS 20 (508 mm) IP gas line in the City of Burnaby."

On page 41, FEI states, "the Cape Horn Gate Corridor option involves the installation of approximately 8 km of NPS 20 IP gas line in the Cities of Coquitlam and Burnaby."

On page 42, FEI states, "the Fraser Gate Corridor option involves the installation of approximately 7 km of NPS 20 (508 mm) IP gas line starting at Fraser Gate Station in the City of Vancouver."

9.1 Please explain in detail FEI's rationale for selecting an IP pipeline to replace the existing DP pipeline.

**Response:**

A gas pipe operating at a higher pressure will have more delivery capacity than the same diameter gas pipe operating at a lower pressure. FEI selected the higher IP rather than DP operating pressure, for these alternatives in order to maximize the delivery capacity for the selected pipe diameter – at a marginal additional cost. Refer to the response to BCUC IR1 3.2 for additional discussion on the how the pipe diameter and operating pressure for alternatives was selected. Refer to the response to BCUC IR1 9.4 for discussion on the estimated cost differential.

9.2 Did FEI consider using a DP pipeline for alternatives 6A, 6B and 6C?

9.2.1 If not, please explain why not.

**Response:**

A DP pipeline was not considered for Alternatives 6A, 6B and 6C given the increased capacity benefits and the low marginal cost of an IP pipeline solution as described in the response to BCUC IR1 9.1.

9.3 Please describe the regulatory process and associated time frame for permitting an IP pipeline used by FEI in the Metro Vancouver area, from early consultation to commissioning, and compare this to the regulatory process for the same project if the pipeline were DP.

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

Permitting for IP and DP gas lines used by FEI in the Metro Vancouver area both involve the same process for early consultation, construction, and commissioning with many permitting agencies. These include municipal permits, some provincial and federal permits, and foreign utility crossing agreements. These permits vary in complexity and timing, with some taking 4 to 8 months for review and approval. FEI holds operating agreements with most municipalities in Metro Vancouver. Only works not covered by these agreements would require specific permits (such as traffic management plans). The project will also require review by the municipality to prevent conflict with their infrastructure.

The primary difference between IP and DP infrastructure is whether permitting for construction and operation is under the BC Oil and Gas Commission (BCOGC) or Technical Safety BC (TSBC). The jurisdiction of these two agencies splits at a Maximum Operating Pressure (MOP) greater than 700 kPa, as defined in the *Gas Safety Regulation*. Therefore, an IP gas line (operating above 700 kPa) is regulated by the BCOGC, while a DP main (operating below 700 kPa) is regulated by TSBC.

In relation to IP gas lines, FEI intends to submit an amendment application to the BCOGC for the Project, referred to as a “Major – New Land Pipeline”, seeking permission for new gas line construction with a new ROW. This process requires a 200 metre consultation and notification radius around the outer boundaries of the Project’s footprint. With IP gas lines, many provincial permits issued by the Ministry of Forests, Lands and Natural Resources Operations and Rural Development (MFLNRORD) are permitted through the BCOGC, including Short Term Water Use (Section 10) and Changes In and About a Stream (Section 11) Authorizations. This allows for the BCOGC process to be more streamlined. Other required deliverables for the amendment application include First Nations consultation, environmental assessments, archaeological impact assessment and design drawings. The process for compilation and review of permit applications generally takes 7 months.

FEI has a standing permit with TSBC for DP main installation and operation, and hence no formal permitting process is required. Under the standing permit, FEI is required to provide TSBC with the construction and materials information, and the operating standards adopted when installing and operating new DP gas lines. Further, FEI is required to provide TSBC with a report of the total length of DP gas line extension installed by the Company, as outlined in Section 50.2 of the *Gas Safety Regulation*.

9.3.1 Please also elaborate on the difference in pipeline rights of way (ROW) requirements, if any.

**Response:**

As described further below, other than the inclusion of the Section 219 Covenant requiring the property owner to obtain written consent prior to any activity within the ROW area, the ROW requirements for DP and IP gas lines are generally the same.

The ROW agreement for IP gas lines includes a covenant under Section 219 of the *Land Title Act* prohibiting the property owner from carrying out activities within the vicinity of the ROW area without the prior written consent of FEI. If such consent is granted, it may only be done in accordance with the written requirements of FEI. The IP ROW agreement also addresses prohibited and permitted improvements and the costs and expenses associated with any damage caused to FEI's works, the Owner's improvements of other Owners, or the requirement to relocate or modify either.

Under the *Oil and Gas Activities Act*, property owners or the public require written permission or a permit from FEI in order to carry out any ground activities within 30 metres of an IP or transmission pressure (TP) gas line. Improvements or ground activities within 30 metres of a DP gas line require the person to advise BC 1 Call of the proposed activity and may require an FEI inspector on site if the DP pipeline diameter is greater than 273 millimetres (NPS 10); however, a permit is not required.

.

9.4 Please describe the material specifications and construction methods for an IP pipeline used by FEI in the Metro Vancouver area, and compare these to the material specifications and construction techniques for the same project if the pipeline were DP.

9.4.1 Please also elaborate on the difference in material and construction cost, if any.

**Response:**

The table below highlights the material specifications for IP and DP gas lines for the PGR Project:

| Parameter | IP (2070 kPa) | DP (700 kPa) |
|---|---|---|
| Steel Grade (Gr.)[5] | 414 | 414 |
| Wall Thickness (W.T.) | 9.5 mm | 4.8 - 9.5 mm |
| Category[6] | CATII M20C | CAT I |

FEI is proposing to use a consistent 9.5 millimetre wall thickness for all IP pipe installed for the Project. A consistent wall thickness provides efficiency in the procurement, manufacturing, construction and long-term asset management through inline inspection (ILI) of the gas lines. The selection of 9.5 millimetre wall thickness and 414 steel grade pipe is required to accommodate the pull loads and stresses during HDD pipe installation[7].

Due to different asset management practices for the DP gas line, FEI will use varying wall thickness for the DP portion of the Project.

Construction methods would be similar for the IP and DP gas lines. CSA Z662:19 Tables 4.9 and 12.2, and the MOTI Utility Policy Manual Table 17.1 require similar depth of cover for installation. The table below outlines the minimum requirements:

| Standard | Parameter | IP (2070 kPa) | DP (700 kPa) |
|---|---|---|---|
| CSA Z662:19 Table 4.9 & Table 12.2 | Below travelled surface (road) | 0.6 – 1.2 m | 0.6 m |
| | Right of Way (road) | 0.6 – 0.75 m | 0.6 m |
| | Below base of rail (uncased) | 2.0 m | 2.0 m |
| | Right of Way (rail) | 0.75 m | 0.75 m |
| MOTI Table 17.1 | Under pavement and shoulders | 1.2 m | 1.2 m |
| | Design ditch bottom | 1.0 m | 1.0 m |
| | Elsewhere in the Right-of-Way | 1.0 m | 1.0 m |

Hydrostatic testing of the IP gas line will require a strength test at 140 percent of maximum operating pressure (MOP) for 4 hours followed by a leak test at 110 percent of MOP for 4 hours, whereas the DP will require a leak test only. As per CSA Z662:19 Clause 12.7.4 and FEI internal standards, gas lines operating greater than 700 kPa require 100 percent Non-Destructive Investigation (NDI) of all welds, while gas lines operating at or below 700 kPa require 15 percent NDI of all welds.

5 As per CSA Z245.1-18 Standard for Steel Pipe.
6 As per Clause 5.2.2 “Notch toughness requirements — Steel pipe” of CSA Z662:19.
7 For pipe installed using HDD methods ASCE Report 89 - *Pipeline Crossings* recommends the diameter to thickness ratio should be less than 60.

When considering the impacted construction activities on a cost per metre basis for a DP gas line, as compared to an IP gas line, FEI estimates that a construction cost reduction of approximately 2 to 4 percent may be achievable if the entire 5 kilometres of the Project were to use a DP gas line. This does not take into consideration any increase to pipeline diameter as may be needed to meet capacity requirements as discussed in the response to BCUC IR1 9.1.

**10.0 Reference: EVALUATION OF ALTERNATIVES 6A, 6B AND 6C**

**Exhibit B-1, Section 4.4.2, p. 44**

**Schedule Impacts**

On page 44 the Application, FEI states:

> The following non-financial evaluation criteria were used to evaluate the three route corridors:
>
> 1. **Schedule Impacts**: the ability to ensure the new system will be in-service to meet the MoTI schedule, impacted by several factors including:
>    - Estimated timelines for meaningful engagement to obtain the necessary permit approvals required for project execution; and
>    - Estimated timelines for construction with regard to municipal bylaws which restrict working hours, traffic management staging as required by the City, working in and around existing third party utilities and construction methodologies.

10.1 Please provide the estimated timelines for engagement and construction and the overall schedule for each of the three route corridors.

10.1.1 Please include any assumption FEI has made and the basis for the assumption.

**Response:**

The overall Project schedule duration for an alternative is driven by the durations of the summary activities that are most likely to be on the critical path, which are design, permitting and construction. As such, for reasons discussed in Table 4-5 in the Application, factors such as permit approval times and utility obstructions influence the overall duration. In conducting the alternative analysis, FEI concluded the following:

- For Alternative 6A, the durations for the summary activities, engagement, design, permitting and construction are likely to be executed with durations in the lower to mid ranges of the estimates because of fewer land issues and obstructions. The high-level estimates for the summary activities are approximately 6-9 months for design, 9-12 months for permitting and 6-9 months for construction. When integrated into the master project schedule a likely outcome for the overall project duration could range from 33-45 months.
- For Alternatives 6B and 6C, the durations for the summary activities, engagement, design, permitting and construction are likely to be executed with durations in the mid to upper ranges of the estimates because of coordination with multiple municipalities and a more congested construction environment. The high-level estimates are approximately 9-15 months for design, 12-18 months for permitting and 9-12 months for

construction. When integrated into the master project schedule a likely outcome for the overall project duration could range from 45-63 months.

The assumptions FEI made are as indicated in Table 4-5 of the Application and are based on FEI's experience with similar urban gas line projects. In FEI's view, specifically for Alternative 6A, the Gaglardi Route would likely consume less schedule contingency and have a narrower range for the following reasons:

- The Project does not cross private land so no private land SRW negotiations are required;
- Permitting is only required from one municipality; and
- There is less overall congestion due to third party utilities in route corridor compared to other alternatives.

Therefore, in FEI's view, Alternative 6A would most likely require less contingency than estimated and achieve the Project schedule constraint to meet MoTI's Pattullo Bridge Replacement project timelines.

10.2 What construction techniques has FEI considered or could FEI consider to shorten timelines for permitting approval or construction?

**Response:**

For installation of the gas line, FEI plans to use standard urban pipeline construction techniques that have been developed and proven successful on FEI's previous IP and CTS projects, including stove pipe and drag section installations. An alternative installation technique that is under evaluation to reduce the construction and permitting schedule includes a long horizontal directional drill (HDD) to minimize traffic management staging, permitting from various local, provincial and federal authorities, and working in and around existing third-party utilities.

Another opportunity to reduce construction schedule is to implement multiple construction crews over various sections of the alignment. Traffic management staging will require further evaluation to determine the feasibility and impacts.

10.3 When evaluating the alternatives, please discuss whether FEI assessed the viability of removing the Pattullo Gas Line to meet MoTI's schedule, in advance of the new system being in-service.

10.3.1 If so, please discuss why this was not deemed to be viable and include a discussion on how the demand forecast informed this decision.

10.3.2 If not, please explain why not.

**Response:**

FEI assessed the impact on the distribution system if the Pattullo Gas Line were removed in advance of the new system being in service. However, such a schedule was deemed not viable. The removal of the Pattullo Gas Line without a replacement supply leaves the remaining system incapable of providing sufficient capacity at several district regulating stations during peak winter conditions. The risk of entering a winter period with a distribution system unable to meet FEI's forecast peak demand does not meet FEI's design criteria and could result in significant customer outages, both of which are unacceptable to FEI.

The peak demand forecast provides an estimate of customer demand under peak conditions in each future year. FEI uses a 1 in 20-year return period for calculating winter average temperatures under which peak demand occurs. This implies that there is roughly a 5 percent possibility that FEI will experience peak demand in any given year. When the demand forecast load for FEI consumers is applied to a model of the distribution system, FEI can estimate the required flow through stations and gas lines, including the pressures at station inlets and other delivery points in the system. Models show that, under peak demand and without the Pattullo Gas Line, the inlet pressure in the existing trunk distribution system will be inadequate for several stations in the system to deliver the forecasted flow. The imbalance created between the reduced flow capacity through the station and the unchanged consumer demand downstream results in a steady decay of pressure in the downstream system eventually resulting in customer outages.

**11.0 Reference: EVALUATION OF ALTERNATIVES 6A, 6B AND 6C**

**Exhibit B-1, Section 4.4.2, p.43**

**System Resiliency**

On page 43, FEI states:

> The replacement of FEI's distribution system resiliency was not included as a criterion in the Overland Gas Line alternatives evaluation as all three route corridors would erode the existing system resiliency by requiring other major gate stations in the system to provide the capacity previously provided by the Pattullo Gas Line. Alternatives 6A and 6C will shift the Pattullo Gas Line load onto Coquitlam Gate and Fraser Gate, respectively, consuming a portion of the available capacity in the Transmission pressure gas lines feeding these stations and the IP gas lines leaving these stations. Similarly, Alternative 6B erodes resiliency by either:
>
> - Consuming a portion of the transmission gas lines' capacity feeding Coquitlam Gate, thereby effectively limiting the available supply from Coquitlam Gate station should Fraser Gate fail; or
> - Consuming a portion of the available capacity at the gas lines into or out of Fraser Gate should the Port Mann crossing supplying Cape Horn and Coquitlam Gate stations fail.

11.1 How frequently (per annum) does FEI experience failures at these gate stations?

**Response:**

The response to BCUC IR1 5.1 outlines FEI's definition of resiliency and how it applies to customer reliability and failures.

For additional context, there are two types of "failure" that FEI could experience at these gate stations:

1. A "system failure" is a failure where downstream customers experience a loss of gas supply. The outage can apply to some or all customers downstream of the failure.
2. A "component failure" is an instance where a piece of equipment within the system is not operating as intended. A component failure can occur without causing a system failure, due to redundancy of equipment within the system.

Although FEI has not experienced any "system failures" at its major gate stations, these failures are possible – and could lead to significant consequences leaving customers with no gas supply over extended periods.

FEI periodically experiences "component failures" throughout its asset base. Corrective measures are undertaken to replace or repair components in order to restore functionality when failures are discovered by operational problems or by inspection. A survey of the Fraser Gate and Coquitlam Gate component failure history shows an average of 8 to 10 corrective measures annually per facility.

11.2 Please categorize the reasons for these failures.

**Response:**

Component failures (as defined in the response to BCUC IR1 11.1) at stations such as Fraser Gate and Coquitlam Gate can generally be attributed to the following causes:

- Component wear (e.g., metal on metal and polymer on metal are common);
- Elastomeric breakdown leading to soft-part failure (e.g., due to chemical attack, exposure to UV, exposure to atmosphere or fatigue);
- Contamination/Debris (e.g., scale, dirt, grease, construction debris, or sulphur compounds);
- Electronic failure due to age; and
- Corrosion due to exposure to moisture.

11.3 What steps has FEI taken or could FEI take to reduce the risk of failure at these gate stations?

**Response:**

FEI has several layers of protection in place in order to prevent system failures (as defined in the response to BCUC IR1 11.1) in the event of component failures. This includes designing and installing at least two layers of protection (LOP), primarily in the form of redundant equipment. Stations with high criticality may have up to four LOPs. In this way, component failures can occur without causing a system failure.

To addition to the above, FEI endeavors to mitigate component failures through the creation and execution of maintenance plans. These plans include the following strategies as applicable:

1) Preventative Maintenance: Aims to either restore or extend the life of components, and include the following tasks:
    a. Overhauls/replacing worn parts;
    b. Adjustments and calibrations;

c. Lubrication;
d. Cleaning; and
e. Exercising (i.e. valves).

2) Inspections: The goal of inspections are to determine the condition of a component or piece of equipment in order to carry out preventative maintenance prior to failure, and include the following inspection methods:
a. Visual;
b. Operational checks (particularly in the case of hidden failures);
c. Leak surveys;
d. Vibration analysis; and
e. Thickness measurements.

The maintenance plans in place also evolve as operational experience is gained. This is done through feedback from operations and maintenance and failure investigations in order to prevent future recurrences.

11.4 Please provide the available capacity of the transmission pipelines feeding each gate station.

**Response:**

Similar to the Pattullo Gas Line being described as a component of the trunk distribution system in the response to BCUC IR1 3.1, the transmission lines feeding the Coquitlam Gate and Fraser Gate stations are components of the Coastal Transmission System (CTS). There is no meaningful capacity of a single component of the transmission system as the capacity (or support capability) that the component provides to the system is influenced by how the load on the system is distributed.

However, FEI modelled gas flows in the CTS using the winter 2040-41 forecast peak demand. The capacity provided in this response is the maximum delivery capacity available at each gate station, with the forecast 20-year future load for the other two gate stations relocated to the gate station in question. In addition, the load at the gate station has been adjusted to keep the inlet pressure at that station just above the minimum required design pressure. The minimum inlet pressure for Fraser Gate serving a downstream 1200 kPa system is 1550 kPa. The minimum inlet pressure for Coquitlam Gate serving a downstream 2070 kPa system is 2420 kPa. Given these assumptions and load distribution on the CTS, the capacity of the transmission system serving each Gate Station is as follows:

| Gate Station | Transmission Line Delivery Capacity ($m^3$/hr.) | 20 Year Resiliency Requirement* (m3/hr.) |
|---|---|---|
| Coquitlam Gate | 965,400 | 899,300 |
| Fraser Gate | 887,000 | |

* Sum of 20 year demand of Fraser Gate, Pattullo Gate and Coquitlam Gate

As the table above shows, for the winter of 2040-41 the transmission lines serving Coquitlam Gate station are forecast to have sufficient capacity to deliver the full load of the Metro Vancouver IP Systems by a margin of 66,100 $m^3$/hr. However, the transmission line serving Fraser Gate has a slight deficit in capacity of 12,300 $m^3$/hr below that required to meet the full load of the Metro Vancouver IP Systems. This deficit in capacity for the transmission lines serving Fraser Gate would first appear in the winter or 2040-41 the last year of the 20-year forecast. A means of addressing the slight deficit in the CTS to serve Fraser Gate under these conditions is described in the response to BCUC IR1 11.5.

11.4.1 Please explain FEI's methodology for determining the available capacity, detailing all assumptions made.

**Response:**

Please refer to the response to BCUC IR1 11.4.

11.4.2 Please also elaborate on the difference in available capacity between transmission pipelines, if any.

**Response:**

Please refer to the response to BCUC IR1 11.4.

11.5 Please explain whether FEI has undertaken any assessments of system improvements to increase the capacity of the existing transmission system feeding gate stations, including potential upgrades to compressors or pipelines.

11.5.1 If yes, please describe the assessments undertaken and the assessment results.

11.5.2 If not, please explain why not.

**Response:**

FEI compares the capacity of the CTS to the 20-year peak demand forecast requirements annually and identifies any required transmission pipe and compressor upgrades if needed. When analyzing the capacity of the CTS, the system is tested to the end of the forecast period confirming that the system retains the pipe and compressor capacity to shift the load fully between Fraser Gate and Coquitlam Gate stations or vice versa. Recent analyses also includes the shifting of the load from the Pattullo Gas Line to either of the other gate stations. The CTS currently has sufficient pipe and compression infrastructure to meet the forecasted 20-year peak demand under normal operation. For disruptions requiring the shift of the loads from Fraser Gate and Pattullo Gate to Coquitlam Gate stations, the CTS also has sufficient pipe and compression capacity. For disruptions requiring the shift of the loads from Coquitlam Gate and Pattullo Gate to Fraser Gate, the CTS would require that additional pressure control be installed at Roebuck Valve station in Surrey later in the forecast, in order to accommodate the required delivery to Fraser Gate with existing pipe and compression under peak demand. FEI has identified a possible future need, but has not yet undertaken any assessment of the details of such additional requirements to maintain this level of resiliency over the 20-year period.

As described in the response to BCUC IR 1.5.3, improvements to the transmission system upstream of Fraser Gate or Coquitlam Gate stations will not correct the eroded resiliency within the Metro Vancouver system with the relocation of the Pattullo Gas Line feed. Gate stations such as Fraser Gate or Coquitlam Gate limit excess capacity from an upstream system from improving capacity deficits in a downstream system because they regulate the pressure available to the downstream system to no more than the Maximum Operating Pressure of that system.

11.6 Please provide information on the extent to which Alternative 6A limits the available capacity at Coquitlam Gate for both the current year and the end of the 20-year planning period.

**Response:**

This response also addresses the responses to BCUC IR1 11.7 and 11.8. The table below provides the peak demand flow required at Fraser Gate, Pattullo Gate and Coquitlam Gate stations for the current year and at the end of the 20-year planning period. For comparison, the table also provides the surplus capacity for each alternative and for the current configuration of the Pattullo Gas Line feed above that needed to manage a disruption of the supply into Fraser Gate or Coquitlam Gate, thereby requiring a full load shift. The differences in surplus capacity quantify the extent to which the alternative limits capacity at the gate stations. The method and assumptions for system loading and minimum pressure requirements in this comparison are the same as is described in the response to BCUC IR1 11.4.

Both Alternatives 6A and 6C require that in the event of a supply disruption at Fraser Gate or Coquitlam Gate, the supply of the Pattullo Gas Line must be accommodated by the remaining gate station in addition to the supply of the disrupted station. As a result, these alternatives have an identical impact on the capacity available at Fraser Gate or Coquitlam Gate.

For Alternative 6B, the failure of the Port Mann crossing would require the same magnitude of load shift to Fraser Gate and would result in the same impact on capacity as with Alternatives 6A or 6C. However, for a failure of the supply into Fraser Gate, Alternative 6B would have a lesser impact on loss of capacity at Coquitlam Gate because a portion of the flow would be removed from the transmission lines serving Coquitlam Gate at the proposed Cape Horn station.

The table below illustrates the extent of the capacity reductions of each alternative compared to the current configuration. In both the current year, and at the end of the 20-year planning period, Alternatives 6A, 6B and 6C have the same impact in reducing available capacity into Fraser Gate. In 2040, the available capacity is less than what is required to support the resiliency of the Metro Vancouver system. At Coquitlam Gate, Alternative 6B has a slightly lesser impact on reducing the surplus capacity at Coquitlam Gate than Alternative 6A or 6C. All three alternatives (6A, 6B, and 6C) provide less capacity into each gate station than the configuration with the existing Pattullo Gas Line.

| Year | Alternative | Fraser Gate Supply ($10^3m^3/hr$) | Pattullo Gas Line Supply ($10^3m^3/hr$) | Coquitlam Gate Supply ($10^3m^3/hr$) | Surplus Capacity at Fraser Gate ($10^3m^3/hr$) | Surplus Capacity at Coquitlam Gate ($10^3m^3/hr$) |
|---|---|---|---|---|---|---|
| Current | Current Configuration | 108.4 | 85.2 | 539.4 | 282.7 | 378.1 |
| | 6A or 6C | | | | 226.6 | 305.6 |
| | 6B | | | | 226.6 | 325.8 |
| 2040 | Current Configuration | 134.8 | 106 | 658.4 | 40.9 | 154.7 |
| | 6A or 6C | | | | **-12.3** | 66.1 |
| | 6B | | | | **-12.3** | 78.3 |

11.7 Please provide information on the extent to which Alternative 6C limits the available capacity at Fraser Gate for both the current year and the end of the 20-year planning period.

**Response:**

Please refer to the response to BCUC IR1 11.6.

11.8 Please provide information on the extent to which Alternative 6B limits the available supply at Coquitlam Gate should Fraser Gate fail and at Fraser Gate should the Port Mann crossing fail for both the current year and the end of the 20-year planning period.

**Response:**

Please refer to the response to BCUC IR1 11.6.

11.9 Please describe the extent to which each Overland Gas Line alternative provides full system resiliency in the 20-year planning period.

11.9.1 In your response, please include a table showing for each Overland Gas Line alternative the number of days in a year where full resiliency is not achieved over the next 20 years.

**Response:**

The table below shows the coldest average daily temperature that full resiliency can be achieved in the Metro Vancouver IP system with each Overland Gas Line Alternative. Full resiliency in this context refers to the ability to shift the entire downstream load to either the Coquitlam Gate or Fraser Gate stations. The table indicates the number of days that might occur in a design year where the system would be short of capacity (due to cold temperatures) to completely shift the load. A design year is a hypothetical year where the coldest day represents the coldest day for which a system is designed (in this case minus 12.2 °C) and the remaining coldest days reflect the average of those days from the five coldest years in the preceding 60 year period. This is an established means of describing how many days might exceed a given temperature in a very cold year.

| Year | Coldest Temperature that Full Resiliency Can be Achieved ($T_{avg}$ = Ave. Daily Temp. °C) | | Days Colder than $T_{avg}$ in a Design Year | |
|---|---|---|---|---|
| | Alternative 6A or 6B | Alternative 6C | Alternative 6A or 6B | Alternative 6C |
| 2023 | -8.5 | -12.2 | 3 | 0 |
| 2024 | -8.3 | -12.2 | 3 | 0 |
| 2025 | -8.1 | -12.2 | 3 | 0 |
| 2026 | -8.0 | -12.2 | 3 | 0 |
| 2027 | -7.8 | -12.1 | 4 | 1 |
| 2028 | -7.6 | -12.0 | 4 | 1 |
| 2029 | -7.4 | -11.8 | 4 | 1 |
| 2030 | -7.2 | -11.7 | 4 | 1 |
| 2031 | -7.0 | -11.5 | 4 | 1 |
| 2032 | -6.9 | -11.4 | 5 | 1 |
| 2033 | -6.7 | -11.2 | 5 | 1 |
| 2034 | -6.5 | -11.1 | 5 | 1 |
| 2035 | -6.4 | -10.9 | 5 | 1 |
| 2036 | -6.3 | -10.8 | 6 | 1 |
| 2037 | -6.2 | -10.6 | 6 | 1 |
| 2038 | -6.1 | -10.5 | 6 | 1 |
| 2039 | -6.0 | -10.4 | 6 | 1 |
| 2040 | -5.9 | -10.2 | 6 | 1 |

The table reflects the capacity for resiliency within the Metro Vancouver IP system which is the system most impacted by the replacement of the Pattullo Gas Line. The capacity impact on resiliency for the upstream transmission lines into Fraser Gate and Coquitlam Gate stations have been provided in the response to BCUC IR1 11.6, which shows that there is no capacity reduction in those lines sufficient to reduce the capability for full resilience until 2040. These two systems, the Metro Vancouver system and the upstream transmission system are separated by the gate stations at Fraser Gate and Coquitlam Gate. These stations represent a demarcation between the excess capacity available upstream from alleviating a capacity shortage downstream. As a result, the greater capability of the upstream transmission system is able to improve the capacity to support the resiliency described in the table above.

Alternatives 6A and 6B have the same impact on reducing capacity for resiliency in the Metro Vancouver system and have a greater impact on resiliency than Alternative 6C. Until 2023, the Metro Vancouver system (with the Pattullo Gas Line in service) would have full resiliency to shift load at temperatures as cold as minus 12.2 °C. In 2023 onward with the Pattullo Gas Line replaced, Alternative 6A and 6B would limit that ability to temperatures of minus 8.5 °C or warmer. As load growth occurs on the system each year the temperature at which full resilience can be achieved is warmer than the previous year. Alternative 6C would not see a reduction in capacity to support full resilience until 2027, and then would remain capable of full resiliency at temperatures 4.3 °C colder than Alternatives 6A and 6B (i.e., minus 12.8 °C).

**12.0 Reference: EVALUATION OF ALTERNATIVES 6A, 6B AND 6C**

**Exhibit B-1, Section 1.1, p. 3; Section 4.4.2.2, p. 45**

**Evaluation of Alternatives**

On page 3 of the Application, FEI states:

- FEI's alternatives analysis of available overland gas line route options based on "apples to-apples" Class 5 estimates shows that the route through the City of Burnaby has the lowest rate impact, in addition to be being the only option that can be constructed in time to meet the Project schedule. As such, a more defined level of Project cost is not needed for the analysis of project alternatives.

12.1 Please discuss what the cost, effort and timing of obtaining a Class 4 cost estimate would be for each of the alternatives.

**Response:**

The cost of obtaining an AACE Class 4 estimate and schedule for each alternative varies based on the level of definition, risk, the scope and the extent of investigations required to reduce the uncertainties in the estimate. As per AACE definition, a Class 4 estimate requires:

- Varying levels of project definition (as per AACE guidelines) up to a 10 percent level;
- A cost estimate;
- A project schedule with Level 2 detail (as per AACE guidelines);
- Consultation, engagement, permitting and other planning activities;
- Risk identification and quantification;
- Desktop traffic management study; and
- Initial planning for survey and geotechnical work if required.

In the case of the PGR Project, each alternative had different levels of definition to address the project risk and uncertainty. As such, the cost of producing a Class 4 estimate varied from approximately $0.5 to $1.4 million.

12.2 Please discuss how variations within the class 5 cost estimate range can impact the financial scores of the alternatives. Include examples illustrating the impact at the extremes of the cost range.

**Response:**

To show the sensitivity of the financial scoring of the alternatives to variations in the Class 5 cost estimate range, the table below provides P10, P50 and P90 level estimates for each alternative:

| Alternative | P10 ($Million) | P50 ($Million) | P90 ($Million) |
|---|---|---|---|
| **6A – Broadway and Gaglardi Way Corridor** | 69.7 | 105.0 | 159.0 |
| **6B – Cape Horn Gate Corridor** | 107.7 | 162.5 | 245.5 |
| **6C – Fraser Gate Corridor** | 97.4 | 146.9 | 222.0 |

The table below evaluates the alternatives using the P90 cost for Alternative 6A and the P10 costs for Alternatives 6B and 6C. The final weighted scores in the table demonstrate that Alternative 6A is still the preferred alternative.

| Criterion | Weighting | Alternative 6A Score | Alternative 6B Score | Alternative 6C Score |
|---|---|---|---|---|
| Schedule Impacts | 54% | 3 | 1 | 1 |
| Community, Indigenous and Stakeholder Impacts | 22.5% | 3 | 1 | 1 |
| Environmental and Archaeological Impacts | 13.5% | 1 | 1 | 3 |
| Rate Impact | 10% | 1 | 3 | 3 |
| **Weighted Score:** | **100%** | **2.53** | **1.2** | **1.47** |

On page 45 of the Application, FEI states:

The following financial criterion was used to evaluate the three route corridors:

1. **Levelized Delivery Rate Impact**: Ability for an alternative to be completed with the lowest possible delivery rate impact over the approximate financial life of the asset (i.e., 73-year analysis period) for the PGR Project. Alternatives that minimize the levelized delivery rate impact to FEI's non-bypass customers score the highest. [Emphasis retained]

12.3 Please provide the useful life and depreciation rate(s) FEI proposes to use in its revenue requirements for the PGR Project.

**Response:**

Upon BCUC approval of the PGR Project and once construction has been completed, each individual asset of the PGR Project will enter rate base on January 1 the following year and begin depreciating at the approved depreciation rate for each asset. The current approved depreciation rates for FEI's assets in rate base are based on FEI's 2017 Depreciation Study, approved by BCUC Order G-165-20 as part of FEI's 2020-2024 Multi-Year Rate Plan (MRP) Application and included in the table below. Additionally, included in the aforementioned depreciation study was the average service life (ASL) for each of the assets which FEI has also included in the table below.

| PRG Project Components | FEI Asset Account No. | FEI Asset Account Name | Approved Depreciation Rate (%) | Average Service Life ASL (yrs) |
|---|---|---|---|---|
| **Intermediate Pressure (IP) Pipeline** | 475-00 | Distribution Plant – Main | 1.35 % | 65 |
| **PRS Building Structure** | 472-00 | Distribution Plant – Structures & Improvements | 2.15 % | 38 |
| **PRS Equipment** | 477-10 | Distribution Plant – Measuring & Regulating Equipment | 2.51 % | 33 |
| **PRS Land in Fee Simple** | 470-00 | Distribution Plant – Land in Fee Simple | 0.00 % | n/a |
| **IP Pipeline Statutory Right of Way (SRW)** | 471-01 | Distribution Land Rights | 0.00 % | n/a |

The approved depreciation rate is not equivalent to the average service life estimated by the depreciation study of each asset as shown in the table above. Under group asset accounting, the asset depreciation rate also includes the accumulated gains/losses within the same asset group at the time of the depreciation study. The depreciation rates of each asset account are reviewed and updated periodically with new studies that are filed to BCUC for approval.

FEI notes that the actual physical life of the assets that is useful for providing service can be longer or shorter than the average service life as estimated by the depreciation study and set out in the table above. The need for retirements or replacement is primarily impacted by factors such as third-party relocation requests, system demand growth, system alterations for operating benefits, and integrity concerns. In the absence of external influences or identified integrity concerns, the physical life of the assets such as the pipelines and PRS stations can be longer than the depreciable life of the individual assets.

12.4 Please provide the remaining useful life of the surrounding system and explain if its condition will in any way impact the PGR Project.

**Response:**

FEI confirms that the condition and useful life of the surrounding system will not in any way impact the Project. As discussed in the response to BCUC IR1 12.3, the service life of the surrounding system is primarily impacted by factors such as third-party relocation requests, system demand growth, system alterations for operating benefits, and integrity concerns. In the absence of external influences, system demand growth or integrity concerns, the physical life of the surrounding system is indefinite.

Further on page 45 of the Application, FEI states:

> These cost estimates were based on information available in March 2020, and are considered to be AACE Class 5 estimates. The cost estimates were benchmarked against the LMIPSU Project [Lower Mainland Intermediate Pressure System Upgrade Projects (LMIPSU]. The LMIPSU Project is a particularly relevant benchmark, as it was recently completed and faced similar urban construction challenges that would be expected for the three overland routes considered for the PGR Project. For a fair comparison, future replacement costs in terms of sustainment capital over the 73-year analysis period for each Overland Gas Line alternatives are included.

12.5 Please clarify if the cost estimates of the alternatives will be updated to reflect more recently available information. If not, please explain why not.

**Response:**

The AACE Class 5 cost estimates for Alternatives 6B and 6C will not be updated in FEI's evidentiary update as these alternatives are not feasible, have not been pursued further and, as such, no additional recent information is available. FEI plans to review and update the cost estimate for Alternative 6A (Broadway and Gaglardi Way Corridor) to reflect more recently available information to compare it against the cost estimate for Alternative 6D (Sperling Avenue Corridor) in its evidentiary update.

12.6 Please comment on the similarities and differences in project scope between the PGR Project and the LMIPSU Project.

**Response:**

The similarities in project scope between the PGR Project and the LMIPSU Project are as follows:

- Gas line construction in an urban setting, predominantly within municipal roadways:
    - limited workspace available to accommodate construction activities;
    - proximity and crossings of existing adjacent third-party utilities; and
    - traffic management to accommodate construction activities;
- Early works construction to accommodate environmental timing restrictions;
- Methods of pipeline construction and installation (e.g., stove pipe method, drag section method, in street method, typical cross country method and trenchless installations);
- Pipeline designed to accommodate future in-line inspection (ILI);
- Existing gas line to be decommissioned upon new gas line construction completion; and
- Pipelines and stations designed, constructed and operated in accordance with the same standards and specifications.

The differences in project scope between the PGR Project and the LMIPSU Project are as follows:

- The lineal length of gas line construction is substantially less for the PGR Project with consequently fewer numbers of:
    - trenchless crossings for perpendicular arterial roadway crossings; and
    - crossings of existing third-party utilities.
- Basis of design and engineering:
    - The stations scope of work is substantially less for the Project: one PRS at the terminus to reduce the operating pressure from 2070 kPa to 700 kPa, as compared to major station rebuilds at both Coquitlam Gate Station and East 2nd and Woodland Gate Station;

  - No increase in the MOP for the PGR Project resulting in no upgrades to lateral interconnections as compared to 11 for the LMIPSU Project;
  - No bi-directional gas flow requirement for the PGR Project; and
  - Pipe diameters are different (e.g., NPS 20 as compared to NPS 30).
- One manual block valve installation at the start of the gas line for the PGR Project as compared to three manual and two automated block valves for the LMIPSU Project;
- One municipality to engage with to obtain permits and approvals for the PGR Project as compared to three for the LMIPSU Project;
- Significantly fewer businesses to consult with for the PGR Project; and
- Sections of the existing gas line and stations to be removed upon abandonment and corresponding upstream system modifications for PGR Project are greater.

The similarities and differences as described above are general in nature as FEI has yet to select and confirm the PGR Project's specific gas line routing within the City of Burnaby. As such, any right of way acquisition and environmental and archaeological impacts will vary in comparison to the LMIPSU Project dependent upon whether the Gaglardi Route or the Sperling Route is selected as the preferred route option.

12.7 Please provide the level of accuracy used for the LMIPSU Project cost estimate and its alternatives.

**Response:**

For the LMIPSU Project, FEI conducted a non-financial evaluation of seven alternatives considered against the main criteria which reflected the project's objectives to adopt a solution that would address the issues identified (e.g., pipeline integrity, operational flexibility, system resiliency, and constructability). A financial analysis was then completed for those alternatives that would meet a significant portion of the project's objectives and requirements, as established by the non-financial evaluation. Three alternatives met most of the project objectives and cost estimates were completed in accordance with the appropriate AACE expected accuracy range for a Class or estimate, as follows:

- Alternative 4: Class 4
- Alternative 5: Class 4
- Alternative 6: Class 3

Alternative 6 was deemed to be the only alternative that provided a solution which met all of the stated project objectives, was the preferred alternative for the Project and thus was estimated to a Class 3 level of definition. This approach is consistent with the BCUC's CPCN Application Guidelines.

12.7.1 If different from the PGR Project, please explain why.

**Response:**

The primary difference between the projects is the third-party driven schedule of the PGR Project.

Similar to the LMIPSU Project, for the PGR Project FEI conducted a non-financial evaluation (screening) of six alternatives and sub-alternatives considered against the following Project objectives: (1) to replace the distribution system capacity currently provided by the Pattullo Gas Line; and (2) to complete the PGR Project in advance of the scheduled Pattullo Bridge demolition thereby ensuring continued safe and reliable supply to customers. Alternative 6 was determined to be the only alternative that would allow FEI to achieve these Project objectives.

A further non-financial evaluation and financial analysis was then completed for the three sub-alternatives identified under Alternative 6. The evaluation criteria reflected the Project's objectives and addressed the following issues: schedule impacts, community, Indigenous and stakeholder impacts, and environmental and archaeological impacts. Cost estimates were completed for three overland sub-alternatives in accordance with the appropriate AACE degree of accuracy as follows:

- Alternative 6A: Class 5
- Alternative 6B: Class 5
- Alternative 6C: Class 5

Alternative 6A was deemed to be the only alternative that provides a solution that meets all of the Project objectives and was selected as the Project's preferred alternative prior to the introduction of alternative 6D in July 2020. A feasibility assessment of Alternative 6D is currently underway. FEI intends to develop a cost estimate with a Class 4 degree of accuracy for the preferred alternative, 6A or 6D, to be filed with its evidentiary update.

12.7.2 If different, please explain how the PGR Project cost estimates can be benchmarked to the LMIPSU project costs.

**Response:**

FEI is in the process of completing the PGR Project's cost estimate to a Class 3 ACCE level of accuracy, consistent with the LMIPSU Project cost estimate, but this is not expected to be completed until April 2021. FEI will be filing a Class 4 estimate in its evidentiary update. As discussed in the response to BCUC IR1 12.7.1, the difference in the level of definition between the projects at the time of the respective CPCN applications is due to the third-party driven schedule of the PGR Project.

Nonetheless, the LMIPSU Project can be used as an appropriate benchmark for the PGR Project because both projects are of comparable scope, but different scale, as described in the response to BCUC IR1 12.6. For example, by being of comparable scope, the pipeline component of the PGR Project is expected to have similar production rates in an urban environment as the LMIPSU Project, so FEI used the latter's historical production rates to derive the estimated production rates for the PGR Project.

12.8 Please provide a breakdown of the forecast and actual LMIPSU Project costs and comment on the significant variances and construction challenges faced with the LMIPSU Project.

**Response:**

The LMIPSU Project consists of both the Coquitlam Gate IP project (which was largely completed in late 2019, and represented the majority of the total project costs), and the Fraser Gate IP project (which is scheduled for completion in 2021). Since construction of the Fraser Gate IP project has not yet started, and the Coquitlam Gate IP project comprises most of the project costs, this response addresses only the latter project. The capital cost details, as provided in FEI's Q3 2020 Progress Report to the BCUC, including forecast (Forecast Total at Completion column - 5) and actual (Spent to Date – column 3) up to September 30, 2020, are presented below:

| Description | CPCN Estimate (1) | Revised Control Budget - Feb 2018 (2) | Spent to Date (3) | Estimate to Complete (4) | Forecast Total at Completion (5) = (3)+(4) | Variance Over / (Under) (6) = (5)-(2)/(2) | Percentage Budget Spent (7=(3)/(2)) |
|---|---|---|---|---|---|---|---|
| | ($000s) | | | | | (%) | |
| **Project Management** | **1,626** | **13,409** | 11,151 | 587 | 11,738 | -12% | 83% |
| **EPCM** | **13,293** | **43,583** | 31,750 | 947 | 32,697 | -25% | 73% |
| **Permits and Approvals** | **5,695** | **16,054** | 3,604 | 3,757 | 7,361 | -54% | 22% |
| **Property and Right of Way** | **1,137** | **5,442** | 1,280 | 150 | 1,430 | -74% | 24% |
| **Materials** | **29,873** | **27,949** | 26,335 | 0 | 26,335 | -6% | 94% |
| **Inspection** | **5,157** | **10,641** | 6,934 | 10 | 6,944 | -35% | 65% |
| **Construction** | **135,551** | **304,916** | 296,301 | 4,114 | 300,415 | -1% | 97% |
| **Tie-in and Commissioning** | **1,049** | **4,553** | 3,643 | 1,129 | 4,772 | 5% | 80% |
| **Contingency** | **29,632** | **36,042** | 0 | 11,212 | 11,212 | -69% | 0% |
| **PST** | **3,292** | **1,651** | 1,762 | 0 | 1,762 | 7% | 107% |
| **Sub-total** | **226,305** | **464,239** | 382,759 | 21,906 | 404,665 | -13% | 82% |
| **AFUDC** | **12,236** | **28,752** | 17,954 | 0 | 17,954 | -38% | 62% |
| **Total** | **238,541** | **492,991** | 400,713 | 21,906 | 422,619 | -14% | 81% |
| **Demolition** | **4,169** | **3,940** | 669 | 7,259 | 7,928 | 101% | 17% |
| **AFUDC Demolition** | **115** | **178** | 28 | 89 | 117 | -35% | 16% |
| **Total Capital Cost - Coquitlam IP** | **242,825** | **497,109** | **401,410** | **29,254** | **430,663** | **-13%** | **81%** |

The capital cost for the Coquitlam Gate IP project is currently forecast to be $430.663 million. This amount is $66 million or 13 percent less than the Revised Control Budget (column 2). The negative variance is largely due to fewer stakeholder requirements than anticipated and improved relations and communications with stakeholders.

The actual contingency to date is shown as zero because schedule risks did not materialize and hence the associated cost impact did not occur or was recorded within each applicable line item. FEI has identified extra costs such as a facilities claim and miscellaneous restoration costs in the contingency line item in the event these items materialize. In addition, there were cost savings opportunities in nearly all line items which reduced the need to draw down the contingency.

The major construction challenges encountered include:

- Managing public impacts, in the form of traffic congestion, construction activity and noise;
- Delays in receiving municipal, government and third-party permits and approvals including changes to traffic control plans;
- Unanticipated third-party utilities;
- Unanticipated sub-surface conditions and obstructions encountered along trenchless crossings; and
- Schedule delays in the completion of the facilities.

**13.0 Reference: EVALUATION OF OVERLAND GAS LINE ALTERNATIVE**

**Exhibit B-1, Section 4.4.1.4, p. 42**

**Alternative 6D – Sperling Avenue Corridor**

On page 42 FEI states:

> At the time of filing this Application, FEI is investigating the feasibility of Alternative 6D. FEI will provide a description of this route in an evidentiary update, after it has consulted with the City of Burnaby and other stakeholders.

13.1 Please confirm, or otherwise explain, that FEI intends to provide an evidentiary update to the Alternative Evaluation section of the Application.

**Response:**

Confirmed. FEI intends to update Section 4.4 of the Application as part of the evidentiary update, which will include the evaluation of Alternative 6D.

## C. PROJECT COST ESTIMATE

**14.0 Reference: PROJECT COSTS**

**Exhibit B-1, Section 1.1, p. 2;**

**Exhibit B-6 (Evidentiary Status Update), p. 2; Appendix A, p. 1**

**Work to be Completed Prior to Expected CPCN**

On page 2 of the Application, FEI states:

> In order to meet the stringent Project schedule requirements driven by the Province's Pattullo Bridge Replacement Project, FEI must initiate the detailed design and procurement of long lead material items in the first quarter of 2021.

**14.1 Please provide a breakdown and detailed description of the proposed work to be completed and materials to be procured prior to the expected CPCN decision. Include all associated costs.**

**Response:**

A breakdown and detailed description of the proposed work to be completed and materials to be procured prior to the expected CPCN decision, based on a July 2021 Decision date, is as follows:

- Completion of geotechnical borehole investigations and engineering survey programs;
- Completion of Class 3 cost estimate and schedule deliverables;
- Engaging a contractor to provide constructability input and develop a contract price;
- Completion of 90 percent detailed engineering design;
- Application for the majority of the necessary permits required for construction; and
- Placement of purchase orders for long lead material items (e.g., line pipe, casing pipe, control valves, actuator valves).

FEI is currently finalizing the Class 4 cost estimate for the preferred alternative as part of its evidentiary update. As such, FEI is not able to provide the associated costs of the proposed work to be completed or materials to be procured prior to the expected CPCN decision.

**14.2 In a scenario where the CPCN is not granted for the Pattullo Gas Line Replacement Project (PGR Project) please clarify who will bear the risk(s) of any**

project costs incurred (FEI's shareholder or customers). If customers, please explain why and provide the estimated rate increase.

**Response:**

If the CPCN is not granted for the Project, FEI will request BCUC approval to recover project costs incurred prior to the BCUC decision from FEI's non-bypass ratepayers. These costs will have been prudently incurred to meet the stringent Project schedule requirements driven by the Province's Pattullo Bridge Replacement Project and to ensure continued gas service to customers in Burnaby, New Westminster and Coquitlam.

FEI is finalizing the cost estimates of the preferred alternatives as part of its evidentiary update and, as such, FEI is not able to provide an estimate of the rate increase due to the costs incurred prior to BCUC's decision.

FEI provided, in Appendix A to the Evidentiary Update Status, a letter from the City of Burnaby indicating that council supported the fourth route option along the Sperling Route corridor.

On page 2 of the Evidentiary Update Status, FEI states:

> …FEI has continued to progress the engineering designs for the Gaglardi Route in the event that a route in the Sperling Route corridor is determined to be not feasible or not FEI's preferred route.
>
> FEI will be completing its assessment of the feasibility of the Sperling Route corridor, including further consultation and other work needed to complete its Application in the coming weeks.

14.3 Please comment on how the City of Burnaby's support for the fourth route option along the Sperling Route corridor impacts the proposed work to be completed prior to the expected CPCN decision.

**Response:**

The City of Burnaby's support for the Project, regardless of the route corridor chosen, is critical to the planning activities and meeting the Project's schedule milestones. Prior to the City of Burnaby bringing forward the Sperling Route on July 31, 2020, FEI intended to file an application for a CPCN in its entirety by September 30, 2020 for the Gaglardi Route. FEI now intends to file the remaining sections of the Application for the preferred route on December 15, 2020, which has caused a schedule delay of approximately three months to the anticipated

CPCN approval date. As such, an additional three months of project activities will need to be completed prior to CPCN approval (as referenced in FEI's response to BCUC IR1 14.1).

**15.0 Reference: PROJECT COSTS**

**Exhibit B-1, Section 1.1, p. 3**

**Project Definition**

On page 3 of the Application, FEI states:

> …[I]n order to commence the regulatory review process and meet the Project schedule, in the evidentiary update FEI will be providing the PGR Project cost estimate at an AACE Class 4 level of project definition. While the BCUC's CPCN guidelines prescribe an AACE Class 3 level of estimate, FEI believes a Class 4 level of estimate is sufficient in this case, given that:
>
> - FEI will have undertook additional preliminary constructability and other site reviews to better define the Project scope than is ordinarily completed for a Class 4 cost estimate.
> - The Project budget will include a contingency estimate, determined through a comprehensive risk identification process, detailed qualitative assessment and a risk quantification analysis using the latest revision of AACE International Recommended Practices.

15.1 Please discuss what the cost, effort and timing of obtaining a Class 3 cost estimate would be for the PGR Project and comment on the regulatory efficiencies of providing a Class 4 cost estimate.

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

FEI's estimated cost to complete a Class 3 estimate for the Project is approximately $3.5 million. The current timing for completing the Class 3 cost estimate is April 2021. The level of definition of the deliverables required to qualify the estimate as Class 3 will align with AACE RP 97R-18 and, as indicated in response to CEC IR1 2.1, the level of effort required will be consistent with the AACE guidelines.

Developing and filing a Class 3 cost estimate for the Project before submitting the evidentiary update would consume the schedule contingency, while leaving FEI with insufficient time to meet the stringent Project schedule requirements that are driven by the Province's Pattullo Bridge Replacement Project. The regulatory efficiencies of providing a Class 4 cost estimate for the Application enables the BCUC to provide its decision earlier than it would otherwise, will allow FEI to begin early works construction in Q3 2021, and will increase the likelihood of completing the Project with some schedule contingency for the mitigation of construction delays

FEI believes that, in this instance, providing a Class 4 estimate with more than the typical Class 4 level of project definition, is sufficient to support the BCUC's determination that the Project in the public interest.

15.1.1 As comparison, please provide the cost, effort and time required to develop the Class 4 cost estimate for the PGR Project.

**Response:**

FEI's cost to develop the Class 4 cost estimate for the Gaglardi Route is approximately $1.32 million. To maintain the schedule there is an overlap of activities between the Class 4 and Class 3 phases and hence there is some difficulty in identifying the specific costs associated with each phase. The development of the Class 4 deliverables started in February 2020 and was completed in August 2020 for a total duration of seven months. The level of project definition deliverables required to classify a cost estimate is in alignment with AACE RP 97R-18. In general, a Class 4 cost estimate requires 1 to 15 percent project definition. In the case of the Gaglardi Route, the amount spent reflects the additional work done to better define the Project scope and conduct constructability reviews to reduce the project uncertainties.

FEI's cost to develop the Class 4 cost estimate for the Sperling Route is approximately $500 thousand to October 31, 2020. An additional $50 thousand is forecast to complete the Class 4 cost estimate which will be complete in November 2020. The total estimated costs to complete the Class 4 cost estimate are $550 thousand. The development of the Class 4 deliverables began in August 2020 subsequent to the introduction of the Sperling Route by the City of Burnaby on July 31, 2020 for a total duration of 4 months. In the case of the Sperling Route, the amount expended at this time is significantly less than the Gaglardi Route because FEI is still in the process of engaging a CMAR contractor to better define the project, perform traffic management studies and perform constructability reviews. FEI is waiting until the CMAR is engaged to maximize the contractors input, which will provide more assurance of meeting MoTI's schedule deadline. FEI plans to include the cost to develop the Class 4 estimate (including CMAR cost for their services) for Sperling Route in its evidentiary update to be filed on December 15, 2020.

15.2 Please discuss in detail FEI's internal cost estimating practices for capital projects. Please provide any supporting policies, guidance documents or procedures as appropriate.

**Response:**

FEI follows AACE International Inc. (AACEI or AACE) recommended practices for cost estimation. Key documents include:

- AACE RP 18R-97: Cost Estimate Classification System - *As Applied in Engineering, Procurement, and Construction for the Process Industries*; and
- AACE RP 97R-18: Cost Estimating Classification System - *As Applied in Pipeline Transportation Infrastructure Projects*.

The maturity level of project definition is the sole determining characteristic of an estimate class and is roughly indicated by a percentage of complete definition. FEI routinely completes Class 5, 4 and 3 cost estimates for capital projects, and targets a percentage of definition that equates to the class of estimate, to proceed through a Phase Gate project development process.

Included as Attachment 15.2 is FEI's Cost Estimate Classification Guidelines for Operational Assets Expenditures. The table below is an extract from Attachment 15.2 and provides details for FEI's class estimate expected accuracies, purposes, definitions, methodologies and acceptance.

| Estimate Class | Expected Accuracy Range | | Purpose | Project/Maturity Level of Project Definition | Estimating Methodology | Horizon Years | Acceptance | Mechanism |
|---|---|---|---|---|---|---|---|---|
| | Low | High | | | | | | |
| Class 5 **Concept Screening** | -20% To -50% | +30% To +100% | • Long range capital funding levels<br>• Market studies<br>• Preliminary Assessments<br>• Conceptual evaluation of alternative schemes<br>• Preliminary project/concept screening | • 0 to 2%<br>• Conceptual level engineering<br>• Route/locations identified through maps<br>• Affected external stakeholders identified<br>• System parameters identified<br>• Internal Stakeholder knowledge agreement/signoff | • 'Rule of Thumb' costing<br>• Historical data<br>• Judgment based | 5 - 20 | Acknowledgment Capital Initiation Document/Business Case sign off | Attendance at Capital Planning Meeting, List of Projects, documented in the minutes<br>Manager Review |
| Class 4 **Study or feasibility** | -15% To -30% | +20% To +50% | • Detailed strategic planning<br>• Business case assessment<br>• Project screening at a more developed stage<br>• Confirmation of economic and/or technical feasibility<br>• Evaluation of alternative schemes | • 1 to 15%<br>• Pre-FEED[1] to FEED[1] level engineering<br>• Route/locations researched through land checks<br>• Affected external stakeholders identified and risk assessed<br>• System parameters defined<br>• System limitations defined<br>• Preliminary operational contingency plans identified<br>• Equipment parameters identified<br>• Major material list compiled<br>• Project schedule at concept level | • Preliminary estimate with risk conceptualized<br>• Historical data<br>• Gross unit costs<br>• Budgetary equipment and material quotes<br>• Develop construction labour and equipment crew costs | 3 - 5 | Alternative evaluation | Review with Engineering, PMO, Operations |
| Class 3 **Budget authorization or control** | -10% To -20% | +10% To +30% | • Project Funding authorization<br>• First control estimate or project budget<br>• Approval to proceed to next stage or control gate | • 10 to 40%<br>• FEED[1]-level engineering<br>• Prepare Design Basis Memorandum<br>• Final route/locations defined and researched<br>• Operational contingency plans developed<br>• Non standard equipment specifications<br>• Material list<br>• Project schedule at task level<br>• Project Execution Plan<br>• Affected stakeholders consulted and agreement reached | • Budget estimate with risk identified<br>• Budgetary equipment and material pricing<br>• Develop construction labour and equipment crew cost and incorporate in cost estimate<br>• Budgetary pricing on work components (if required) | 1 - 2 | Stakeholder Acceptance (PMO, Operations, Engineering, Lands, Planning or Asset Management) | Project charter (scope, schedule, cost estimate, etc) |

*Notes:*

*(1) FEED – Front End Engineering Design*

*(2) Approval of projects are typically Class 3 however for repetitive or program based work will often be sought on the basis of classification 4 for individual projects with the understanding that the overall program budget will be managed within +/- 10%.*

15.3 Please provide the level of cost estimate that will be used for internal budget approval of the PGR Project. If different from that to be provided to the BCUC as part of the Evidentiary Update, please discuss why.

**Response:**

In accordance with AACE recommended practices, the internal budget will be based on the preferred alternative approved by the BCUC and the Class 3 cost estimate (to be developed by April 2021). This initial basis of Project cost control will continue to be refined as more information, such as firm contract bids, is received.

However, due to the stringent Project schedule requirements imposed by the Province (i.e., demolition of the existing Pattullo Bridge in 2023), FEI will be utilizing the Class 4 cost estimate for its CPCN submission to the BCUC, as discussed in detail in Section 1.1 of the Application.

15.3.1 Please specify the FEI personnel that are / will be responsible for providing internal authorization of the anticipated cost estimate for the PGR project.

**Response:**

Once FEI receives a favourable decision on the Application from the BCUC, and following the receipt of firm bids, a revised internal control budget is established which is used for monitoring and controlling Project actual costs. This budget (updated cost estimate) is reviewed and accepted by the executive sponsor (Vice President, Major Projects).

15.4 Please elaborate on the additional preliminary constructability and other site review that was/will be undertaken to better define the scope of the PGR Project. Please comment on how this extra work aligns with the AACE guidelines for the degree of accuracy in the cost estimate.

**Response:**

In accordance with AACE recommended practices, a Class 4 level of project definition is primarily based on desktop review exercises (augmented with limited site investigations) and a top down estimating approach using factored or parametric models for developing the cost estimate. FEI has undertaken additional preliminary constructability and other site reviews for the Gaglardi Route, and is in the process of doing the same for the Sperling Route. The modifications to the estimating methodology during development of the Class 4 cost estimate, which better define the scope of the Project and reduce uncertainties in the estimates' expected accuracy range, included:

- Additional site visits and site reviews including all relevant subject matter experts input;
- Additional traffic management studies;
- Additional consultation and engagement with stakeholders and the public to evaluate and incorporate feedback into project planning activities;
- Additional detailed mapping to evaluate the impacts of indications of the features and characteristics of the Project;
- Additional investigations on trenchless crossing feasibilities including a comprehensive review of existing geotechnical reports in and around the vicinity of the Project's footprint;
- Obtaining construction management personnel to review the Project plans;
- Additional independent reviews of the cost estimate(s) and estimate assumptions including a review of the materials, take-offs, productivity rates, etc.; and
- A bottom up approach to the cost estimate using semi-detailed unit costs.

15.5 Please discuss the risks and uncertainties that will be addressed by the anticipated cost estimate.

**Response:**

FEI will undertake a comprehensive risk assessment process and discuss the risks and uncertainties associated with the Project in its evidentiary update as part of Section 5 of the Application.

FEI's comprehensive risk assessment process will be in accordance with AACE RP 62R-11 Risk Assessment: *Identification and Qualitative Anal*ysis in order to identify and prioritize the Project specific risks and uncertainties. For example, the risk identification process considers events or circumstances that are likely to affect the Project, including delays, failures of horizontal directional drills, impacts on stakeholders, and impacts on Project scope changes.

15.6 Please clarify whether FEI conducted, or will conduct, a formal risk analysis and/or a Monte Carlo analysis of the project in an effort to determine the appropriate contingency. If not, why not.

**Response:**

FEI will conduct a formal risk analysis using an integrated, hybrid method to develop cost and schedule contingency and management reserve estimates. The analysis will address the first principles of contingency determination as defined by AACE RP 40R-08, including:

- Aligning the method with the risk type: systemic or project-specific;
- Employing empiricism;
- Explicitly and directly linking risks and their impacts; and
- Integrating the cost and schedule risk analysis.

The methods are also aligned with AACE RP 42R-08 latest revision (Risk Analysis and Contingency Determination Using Parametric Estimating) and AACE RP 65R-11 latest revision (Integrated Cost and Schedule Risk Analysis and Contingency Determination Using Expected Value) applied in an integrated hybrid approach. These tools are applied to systemic and project-specific risks and a Monte Carlo simulation is used to combine the risks together into a single probabilistic output.

15.7 Considering FEI undertook steps to better define the scope of the projects and applied a comprehensive risk identification process, please discuss how this impacts the anticipated contingency amount and explain how the contingency will be determined.

**Response:**

As described in the response to BCUC IR1 15.6, the methodology that FEI uses to compute contingency is aligned with AACE RP 42R-08 and RP 65R-11. The methodology evaluates systemic risks which are defined as characteristics of the project system and reflects the uncertainty of the project scope at a certain point in time. Higher levels of scope definition are treated in the methodology as a corresponding percentage reduction in contingency. As a result, by FEI undertaking more work to better define the scope, the systemic component of the contingency is reduced. This is reflected in the final contingency amount that is calculated for the Project. The methodology was developed by Validation Estimating LLC and will be described in the risk report to be filed in the evidentiary update.

15.7.1 Please explain whether the contingency will be refined from a Class 4 cost estimate to better reflect the additional work completed or anticipated to be completed. If not, why not?

**Response:**

FEI confirms the contingency estimate will be refined from a Class 4 cost estimate to better reflect the additional work completed. Please refer also to the response to BCUC IR1 15.7.

15.8 Please explain whether in addition to a contingency FEI anticipates maintaining a capital reserve fund, or similar, for the PGR Project.

**Response:**

As described in the response to BCUC IR1 15.6, FEI intends to conduct a risk analysis to determine whether FEI will propose maintaining a capital reserve (management reserve) fund, or similar, for the Project. FEI will include the risk analysis in its evidentiary update.

15.8.1 If so, please provide the expected size of the project reserve and explain how it was determined.

**Response:**

Please refer to the response to BCUC IR1 15.8.

15.8.2 If so, please clarify the authorizations that would be required to access any project reserve.

**Response:**

As defined in AACE RP 10S-90, management reserve or project reserve is an amount added to an estimate to allow for discretionary management purposes outside of the defined scope of the project, as otherwise estimated.

Should the need arise to access the management reserve during Project execution, a request for additional funds will be submitted to the Executive Sponsor detailing the additional scope or conditions that have materialized. Upon approval from the Executive Sponsor, the Project baseline cost will be increased by the amount requested and the management reserve will be reduced correspondingly.

15.8.3 In a scenario where project costs exceed the anticipated budget, including the project reserve as applicable, please explain how this will be addressed.

**Response:**

Cost estimating is a predictive process and always has an element of uncertainty described by an accuracy range. The accuracy range provides an indication of the degree to which the final cost outcome of a project may vary from the single point value used as the estimated cost for a project. Depending on the technical project deliverables (and other variables) and risks associated with each estimate, the accuracy range for any particular estimate is expected to fall within the computed accuracy ranges. As described in FEI's response to BCUC IR1 15.6, the risk analysis to be conducted will establish the +/- accuracy range for the Project. Any expenditures in excess of the Project reserve would require additional internal approvals, which, depending on the magnitude, may include authorization from the President and CEO and/or the Board of Directors.

15.9 Please clarify if there are or are expected to be any contributions in aid of construction, grants or other funding, or credits related to the PGR Project. If yes, please specify the anticipated source(s) and amounts.

**Response:**

FEI is not expecting any contributions in aid of construction, grants, other funding, or third-party credits related to the Project.

15.10 Please confirm, or explain otherwise, that the allocation of costs will be in accordance with Generally Accepted Accounting Principles (GAAP).

**Response:**

FEI confirms that all costs that are included in the referenced Project capital cost are eligible for capitalization under US GAAP.

Further on page 3 of the Application, FEI states that "[w]hile a Class 4 estimate has a wider accuracy range than a Class 3 estimate, only prudently incurred costs may be recovered from customers in rates in any case

15.11 Please explain if prior to the PGR Project being added to rate base it is FEI's intent to file with the BCUC a complete breakdown of the final costs of PGR Project with a comparison to the cost estimates to be provided in this Application, and an explanation of all material cost variance.

**Response:**

The BCUC provides the reporting requirements for a CPCN as part of its decision approving a CPCN. Consistent with recent FEI CPCN decisions, the utility expects that it will be required to file quarterly or semi-annual reports, and a Final Report six months after the Project is complete. These reports include a breakdown of the final Project costs, along with a comparison to the cost estimate to be provided in the Application, and an explanation of all material cost variances. The addition of the Project costs to rate base will be through a future Annual Review proceeding as part of the current Multi-Year Rate Plan.

**16.0 Reference: PROJECT COSTS**

**Exhibit B-1, Section 1.2.4, p. 7**

**Pattullo Gas Line Removal Costs**

On page 7 of the Application, FEI states the "Project cost estimate will be provided in as-spent dollars including the Allowance for Funds Used During Construction (AFUDC) and cost of removal of the Pattullo Gas Line."

16.1 Please provide the undepreciated capital costs and estimated remaining useful life for the Patullo Gas Line at the time it is expected to be removed from service. Please break down by individual asset, or asset class, as appropriate.

**Response:**

Please refer to the table below for the estimated undepreciated capital cost (i.e. Net Book Value) to December 31, 2023 of approximately $3 million, based on currently approved depreciation rates and the remaining financial life of those assets that are expected to be removed from service as a result of the Project.

As discussed in the response to BCUC IR1 12.3, the term "useful life" can have two interpretations based on either the expected asset financial life determined using the depreciation rate, or the expected asset service life. As the table below shows, theremaining service life of assets can be longer or shorter than the expected remaining financial life. FEI has not estimated the remaining service life of the assets that are expected to be removed from service due to the Project, given the fact that the removal of these assets are not dependent on their age.

| Asset / Facility Description | FEI Asset Account No. | FEI Asset Type | Undepreciated Capital Costs Dec 31, 2023 (Net Book Value) | Remaining Financial Life (Yrs) |
|---|---|---|---|---|
| Pattullo Bridge Crossing - District Station | 467-10 | TP Measuring & Regulating Equipment | $ (31,926) | - |
| Pattullo Bridge Crossing - District Station | 467-20 | TP Telemetry | (63,250) | - |
| Pattullo Bridge Crossing - District Station | 472-00 | DP Structures & Improvements | 540 | 10 |
| Pattullo Bridge Crossing - District Station | 477-10 | DP Measuring & Regulating Equipment | 1,142 | 4 |
| Livingston Pattullo 457 - Transmission Pipeline | 465-00 | TP Main | 1,520,385 | 37 |
| Pattullo - Gate Station | 463-00 | TP Measuring Structures | 88,473 | 10 |
| Pattullo - Gate Station | 467-10 | TP Measuring & Regulating Equipment | 74,735 | 3 |
| Pattullo - Gate Station | 472-00 | DP Structures & Improvements | 43,682 | 33 |
| Pattullo - Gate Station | 477-10 | DP Measuring & Regulating Equipment | 87,380 | 27 |
| Pattullo - Gate Station | 477-20 | DP Telemetry | 62,027 | 19 |
| Distribution Pipeline - New Westminster & Surrey (Incl. on bridge) | 475-00 | DP Main | 1,216,623 | 53 |
| **Total Undepreciated Capital Costs (Dec 31, 2023)** | | | **$ 2,999,810** | |

16.1.1 Please explain the proposed regulatory accounting treatment for the undepreciated capital costs and the estimated annual rate impact for FEI's existing customers.

**Response:**

FEI's summary of the group accounting method used by FEI and other utilities in Canada for retirement of plant in its 2012-2013 Revenue Requirements Application (pages 289 to 290) remains accurate, and is as follows:

> Historically, the FEU have followed recognized regulatory group accounting procedures in accounting or their property plant and equipment. The FEU also adhere to the BCUC Uniform System of Accounts, unless modified by Commission order. Under both of these procedures, on retirement of depreciable gas plant, Accumulated Depreciation is charged with the ledger value of the gas plant retired and the cost of removal less amounts recovered for salvage and insurance. It is only in rare cases where the forces of retirement are outside of the forces that were contemplated in determining depreciation rates that gains and losses on depreciable plant would be recognized in income. Therefore, under historical practice, all normal course gains and losses on retirement of assets are included in accumulated depreciation.
>
> This treatment is appropriate since group depreciation rates are set to recover the asset values over the average service life of the asset group, so that we expect some assets to be retired before their net book value reaches zero; others would be retired after their net book value reaches zero; and overall the gain/loss amount included in accumulated depreciation will have an immaterial value, with any material amounts recovered through changes to future depreciation rates. When depreciation rates are not adjusted to reflect the shorter service lives of assets, or retirements occur in a different pattern than was expected in the last accepted depreciation study, then the loss amount can build in accumulated depreciation.

An excerpt from the BCUC Uniform System of Accounts explains this more fully:

> The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group. It is not the intention of this classification to require the company to keep records of the accumulated depreciation of each unit of plant. For purposes of analysis, however, each company shall maintain subsidiary records in which accumulated depreciation is subdivided according to the utility department to which applicable,

> or to each group of gas plant accounts. When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization.

At the time of retirement and in accordance with typical treatment as noted above, the accounting of the book asset value includes a credit to Gas Plant in Service with an equal debit entry to Accumulated Depreciation.

The retirement will result in a small delivery rate decrease of approximately $150 thousand[8] or 0.02[9] percent compared to the 2021 proposed delivery rates for non-bypass customers given the asset retirements. This is due to the reduction of depreciation expense from the retirement of gross plant. As noted in the 2012-2013 Revenue Requirements Application excerpt above, the gains/losses from the asset retirements will be recovered through changes to future depreciation rates with FEI's next depreciation study which will be subject to BCUC approval.

16.2 Please explain whether FEI expects any asset gains or losses upon the retirement of the Pattullo Gas Line.

16.2.1 If yes, please discuss how the asset gains or losses will be recorded for regulatory accounting purposes and the estimated annual rate impact for FEI's existing customers.

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

As discussed in the response to BCUC IR1 16.1, the asset gains or losses are equivalent to undepreciated capital costs (i.e., Net Book Value) of the asset. FEI adopted US GAAP in 2012 as approved by BCUC Order G-117-11. Therefore, the regulatory accounting treatment for gains and losses from asset retirements will be recorded in accumulated depreciation and recovered using future depreciation ratesPlease also refer to the response to BCUC IR1 16.1.1 for the estimated annual rate impact to FEI's existing customers due to the retirement of assets from the Project.

---

8 $6.623 million gross plant retirement x 1.71% avg. depreciation rate = $113 thousand / (1- tax rate of 27%) = approximately $150 thousand.

9 $150 thousand/$879,286 thousand where $879,286 thousand equals FEI's delivery margin as set out in its Annual Review for 2020 and 2021 Rates.

FEI does not report gains and losses on retirement of assets in the income statement, and pursuant to BCUC Order G-138-14 for FEI's Performance Based Ratemaking Plan from 2014 to 2018, the utility discontinued the use of the Gains and Losses on Asset Disposition deferral account effective January 1, 2014.

16.3 Please confirm, or explain otherwise, that the estimated cost for asset retirement, including but not limited to decommissioning, dismantling and removing the Pattullo Gas Line, will be included in the project cost estimate.

**Response:**

Confirmed. FEI notes the estimated cost for asset retirement is identified as the "cost of removal" in the project cost estimate of the Application and includes decommissioning, dismantling, and removing the assets related to the Pattullo Gas Line. Please refer to the response to BCUC IR1 16.1 for a list of assets to be retired.

16.4 Please discuss whether FEI is responsible for all asset retirement activities, including but not limited to decommissioning, dismantling and removal costs, related to the Pattullo Gas Line.

16.4.1 If not, please provide the party(ies) that also bear responsibility and provide a breakdown of the estimated costs borne by each of the parties.

**Response:**

As per Section 3 of the Bridge Agreement, FEI is responsible for removing the gas line and its attachments from the existing Pattullo Bridge. This includes all asset retirement activities including decommissioning, dismantling and removal costs related to the Pattullo Gas Line. Unless FEI reaches an agreement with MoTI providing otherwise, FEI is responsible for all costs associated with removing the gas line.

**17.0 Reference: ACCOUNTING TREATMENT**

**Exhibit B-1, Section 1.3.2, p. 8; Exhibit B-6 (Evidentiary Status Update), p. 2; Appendix A, p. 1**

**Pacific Northern Gas Ltd. 2013 Revenue Requirements Application – Order G-114-13 and accompanying Decision, Section 6.4, p. 44.**

**PGR Application and Development Costs deferral account**

On page 8 of the Application, FEI states:

> Pursuant to sections 59 to 61 of the UCA [Utilities Commission Act], FEI requests approval of a deferral account, entitled the "PGR Application and Development Costs", to capture the costs of the Application and the costs of developing the PGR Project prior to approval of the Application. The Application costs will include expenses incurred by FEI for the development of the Application for filing, and the regulatory review process such as legal fees, BCUC costs, hearing costs and BCUC-approved intervener costs, a forecast of which is provided in the Application. The Project Development costs include expenses for Project management, engineering, and consultants for assessing the potential design and alternatives.
>
> The Application and Development costs are recorded in the proposed non-rate base deferral account on a net-of-tax basis until January 31, 2020 attracting FEI's weighted average cost of capital (WACC) and will be transferred to rate base on January 1, 2021 with a three-year amortization period. The balance of the Application and Development Costs deferral account is $2.85 million. [Emphasis added]

17.1 Please confirm, or explain otherwise, that FEI intends to record application and development costs in the proposed non-rate base deferral account until January 31, 2020.

**Response:**

Not confirmed.

FEI notes that there are two components which comprise the non-rate base deferral account of $2.856 million:

- For the Project Application costs, FEI is forecasting $350 thousand related to expenses incurred by FEI for the regulatory preparation and disposition of the Application. These expenses include legal fees, BCUC costs, public notice costs, hearing costs (if any), and BCUC approved intervener costs. Consistent with past CPCN applications, FEI will record all costs related to the preparation and disposition of the Application up to the date of BCUC approval in this deferral account which will extend beyond January 31, 2020; and

- For the Project Development costs, FEI is proposing to record $2.506 million to the deferral account. These are <u>actual</u> costs incurred by FEI up to January 31, 2020 associated with project management, engineering, and consultants for assessing the potential design and alternatives for the Project. Development costs incurred by FEI from January 31, 2020 until the BCUC decision will be included as Project capital costs.

17.2 Please confirm, or explain otherwise, that FEI intends to transfer the application and development costs from a non-rate base deferral account to rate base on January 1, 2021.

**Response:**

Not confirmed. Section 1.3.2 of the Application (as referenced in the preamble to this information request) contained a typographical error which incorrectly stated that FEI is proposing to transfer the non-rate base deferral account to rate base on January 1, 2021. FEI clarifies that FEI is proposing to transfer the non-rate base deferral account to rate base on <u>January 1, 2022</u> with a three-year amortization period. Consistent with past CPCN applications approved by BCUC, FEI is proposing to transfer the deferral account to rate base on January 1 of the year following BCUC approval of the application. FEI anticipates a decision for the Project in 2021, and thus is proposing to transfer the non-rate base deferral account to rate base on January 1, 2022.

17.3 Please confirm, or explain otherwise, that FEI requires approval of the proposed deferral account prior to the BCUC's decision on the Certificate of Public Convenience and Necessity (CPCN) for the PGR Project.

**Response:**

Not confirmed. As discussed in the response to BCUC IR1 17.2, there was a typographical error in Section 1.3.2 of the Application. FEI is proposing to transfer the non-rate base deferral account to rate base on January 1, 2022, <u>not</u> January 1, 2021. Consequently, no approval of the proposed deferral account is required prior to the BCUC's decision on the CPCN for the PGR Project.

17.3.1 If confirmed, please specify by when FEI requires approval.

**Response:**

Please refer to the response to BCUC IR1 17.3, which was not confirmed.

17.3.2 If confirmed, please provide responses to the remainder of the information requests in this sub-section.

**Response:**

Please refer to the response to BCUC IR1 17.3, which was not confirmed. However, in order to be responsive, FEI has responded to BCUC IR1 17.3.2.1 to 17.3.2.6.

17.3.2.1 Please provide the forecast balance of the proposed deferral account at December 31, 2020.

**Response:**

As discussed in the response to BCUC IR1 17.2, FEI clarifies that it is proposing to transfer the non-rate base deferral account to rate base on January 1, 2022, not January 2021. As such, FEI has prepared the table below that shows the forecast balance of the proposed deferral account to December 31, 2021:

| | Forecast to Dec 31, 2021 ($ millions) | |
|---|---|---|
| Particular | Application Costs | Development Costs |
| Costs | 0.350 | 2.506 |
| WACC Return | 0.007 | 0.278 |
| ***Total Before Tax Offset*** | ***0.357*** | ***2.784*** |
| Tax Offset | (0.095) | (0.675) |
| ***Total Balance of Deferral*** | ***0.262*** | ***2.110*** |

17.3.2.2 Please provide a breakdown and detailed description of the proposed application and project development costs to be deferred.

**Response:**

Please see the tables below for a breakdown of the proposed application and project development costs to be recorded in the deferral account. A description for each line item is provided below each table:

| CPCN Application | $000s |
|---|---|
| BCUC Costs | $ 70 |
| Interveners Costs | 80 |
| Legal Review | 165 |
| Public Notice | 35 |
| **Total** | **$ 350** |

- **BCUC Costs:** BCUC levy on the CPCN Applications;
- **Interveners Costs:** Interveners Participant Assistance / Cost Award (PACA) as approved by BCUC;
- **Legal Review:** Legal review of the Application; and
- **Public Notice:** Cost of public notice as required by BCUC for CPCN Application.

| CPCN Development | $000s |
|---|---|
| **Project Services** | |
| Archaeological & Environmental | $ 145 |
| Consultation & Engagement | 77 |
| Project Management | 834 |
| Property Services | 5 |
| Regulatory & Permitting | 17 |
| **Engineering** | |
| Design | $ 1,416 |
| Geotechnical | 12 |
| **Total** | **$ 2,506** |

- **Archaeological & Environmental:** Includes development of management plans, internal oversight and audits;
- **Consultation & Engagement:** Includes consultation, engagement and communication with the public, local governments, Indigenous communities, and other stakeholders;
- **Project Management:** Includes project management, inspection services, project support, legal review, and procurement services;

- **Property Services:** Includes work related to potential land and land rights acquisitions;
- **Regulatory & Permitting:** Includes resourcing and coordination of compliance permitting as well as costs for permit applications; and
- **Engineering:** Design / Geotechnical: Includes engineering and engineering support for the pipeline, stations, electrical & instrumentation, civil and geotechnical.

17.3.2.3 Please clarify why January 1, 2021, is selected as the amortization start date for the proposed deferral account.

**Response:**

Please refer to the response to BCUC IR1 17.2.

17.3.2.4 Please explain why FEI is requesting a three-year amortization period for the PGR Application and Development Costs deferral account.

**Response:**

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

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

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

17.3.2.4.1 As part of the above response, please explain whether FEI considered alternative amortization periods and why these alternatives were ultimately rejected.

**Response:**

Please refer to the response to BCUC IR1 17.3.2.4.

17.3.2.4.2 Provide the cumulative financing costs and impact to customer delivery rates based on an amortization period of one, three and five years.

**Response:**

Please see the table below comparing the cumulative financing costs and levelized delivery rate impact in $ per GJ for FEI's non-bypass customers based on an amortization period of one, three, and five years. As clarified in the response to BCUC IR1 17.2, FEI is proposing to transfer the non-rate base deferral account to rate base on January 1, 2022. Once the deferral account is transferred to rate base, the financing cost of the deferral account is effectively FEI's rate base rate of return.

| | Amortization Period | | |
|---|---|---|---|
| | 1 Year | 3 Years | 5 Years |
| Cumulative Financing Costs ($000s) | 74 | 223 | 372 |
| Levelized Annual Delivery Rate Impact ($/GJ) | 0.017 | 0.006 | 0.004 |

17.3.2.5 Please confirm that only project costs that are otherwise required to be expensed as incurred under US GAAP will be recorded in the proposed deferral account. If not, please explain why not and breakdown the forecast project costs proposed to be deferred based on how they are otherwise recorded for accounting purposes.

**Response:**

Confirmed for the application costs. For the development costs, it would be acceptable under US GAAP to capitalize these costs if they were included in the Project's capital cost for ratemaking purposes as discussed in the response to BCUC IR1 17.3.2.7. The financing costs to be included in the deferral account are discussed further in response to BCUC IR1 17.3.2.10. Please refer to BCUC IR1 17.3.2.1 for the breakdown of the deferral account into these three categories.

17.3.2.6 Under a scenario where the BCUC does not approve FEI's request for deferral treatment to the application and development costs, please explain how the costs would be treated.

**Response:**

The Project's application and development costs are prudently incurred as they are reasonable and necessary for the preparation of the CPCN application. The costs, as described in BCUC IR1 17.1 and 17.3.2.2, are consistent in nature with the cost of preparing and developing past CPCN applications which have been granted similar deferral treatment by the BCUC. As such, the deferral treatment of the application and development costs should be approved as filed. Absent BCUC approval, these costs could either be expensed as a flow-through item, or capitalized to the Project cost, either of which would be acceptable to FEI.

In the FortisBC Inc. 2012-2013 Revenue Requirements Application (RRA) Decision (FortisBC Decision)[10], the BCUC established guiding principles for the treatment of deferral accounts, which were subsequently referenced in the Pacific Northern Gas Ltd.'s 2013 RRA Decision[11] and summarized below:

(a) When determining the length of an amortization period for a deferral account, the key factors to consider are the benefits of rate smoothing, the length of time

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[10] FortisBC Inc. - Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan – Order G-110-12 and accompanying Decision, Executive Summary, p. 5.

[11] Pacific Northern Gas Ltd. (PNG West Division) 2013 Revenue Requirements Application – Order G-114-13 and accompanying Decision, Section 6.4, p. 44.

where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on ratepayers due to the accumulation of financing charges.

(b) Deferral accounts are regulatory assets, not true capital assets; therefore, it is more appropriate for deferral accounts for non-capital items to earn an interest rate of return, not a rate base rate of return.

(c) For deferral accounts for non-capital items which are amortized beyond one year, the appropriate return is the utility's Weighted Average Cost of Debt (WACD). For deferral accounts for non-capital items which are amortized over a period of one year or less, the appropriate return is the utility's short term interest cost.

(d) For deferral accounts related to capital, the appropriate return is the utility's Weighted Average Cost of Capital (WACC).

17.3.2.7 Considering the above guiding principles, please explain why an interest rate at FEI's WACC, rather than FEI's WACD, is proposed for the PGR Application and Development Costs deferral account.

**Response:**

In FEI's submission, guiding principles (b), (c) and (d) from the BCUC's Decision on the FortisBC Inc. (FBC) 2012-2013 RRA (Order G-110-12), as summarized in the IR above, are anomalous and incorrect. The BCUC has never applied those principles to FEI, did not apply them to FBC prior to Order G-110-12, and is no longer applying them to FBC in its recent decisions.[12] Whether related to capital or non-capital items, deferrals should attract a rate base rate of return (or an equivalent weighted average cost of capital return for non-rate base deferral accounts) to recognize the financing costs that are associated with the timing difference when there is an outlay of funds and when those costs are recovered from ratepayers (or between when there are costs recovered from customers that will subsequently be returned). Rate base treatment of its deferral accounts is the correct regulatory treatment because it results in the amounts expended on behalf of customers (or, if credits, collected from customers) being financed for rate making purposes at the same rate they are financed by the utility.

However, FEI's proposal for a WACC return on its PGR Application and Preliminary Stage Development Costs deferral account is entirely consistent with the BCUC's determination in Order G-110-12. The items captured in the deferral account are both "related to capital" and are recorded by other utilities as capital. FEI notes that these costs are captured by FBC and other utilities in BC in Account 172 Preliminary Survey & Investigation Costs of the BCUC Uniform

[12] For example, in the MRP Decision, the BCUC approved FBC's request to establish a rate base deferral account for variances between forecast and actual BCUC Levies to be financed at FBC's WACC and FBC's request to establish a non-rate base Earnings Sharing deferral account attracting WACC. As part of Order G-133-20 regarding FBC's Application for Approval of the COVID-19 Customer Recovery Fund Deferral Account, the BCUC approved FBC's request for the aforementioned deferral account to be treated as rate base.

System of Accounts (USoA) which is transferred to capital upon a project proceeding. Account 172 is described in the BCUC Uniform System of Accounts as set out below:

> "This account shall include all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of projects for gas services."

The reason that FEI does not record these items in Account 172 is due to an accounting change made and accepted by the BCUC in FEI's 2010-2011 RRA where FEI had anticipated adopting IFRS. Under IFRS, these feasibility costs would not be eligible for capitalization, and therefore a separate approval from the BCUC for deferral treatment was required. Although FEI eventually adopted US GAAP, where the same concern does not arise, FEI continued with its approved treatment.

The costs incurred by FEI for the PGR application and project development are similar in nature to costs previously approved by the BCUC to receive WACC or rate base deferral account treatment as part of previous CPCN decisions. Examples of this approved treatment include the BCUC's deferral account decisions in the Inland Gas Upgrades (IGU) Project CPCN decision, the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) CPCN decision, and the Huntingdon Station Bypass CPCN decision, among others. As such, the requested deferral treatment for the PGR Application and Development Costs, i.e., attracting a WACC return and transfer to rate base January 1, 2022 (or January 1 of the year following a BCUC decision), is consistent with previous approved requests for this type of deferral.

17.3.2.8 Please identify the relevant factors from FEI's perspective that should be considered in determining the appropriate interest rate for the proposed deferral account.

**Response:**

Please refer to the response to BCUC IR1 17.3.2.7.

17.3.2.9 If FEI were directed to apply a WACD interest rate to the proposed deferral account, please discuss if this would result in a different accounting treatment for regulatory accounting purposes as compared to financial reporting.

**Response:**

No. Please refer to the response to BCUC IR 1.17.3.2.10 for further discussion of regulatory accounting and financial reporting for deferral accounts.

17.3.2.10 Does FEI consider that applying a WACC interest rate to application and development costs is permitted under US GAAP. Please explain why or why not, with reference to the relevant factors that should be considered and the applicable US GAAP section.

**Response:**

ASC 980 is the relevant guidance for rate regulated entities under US GAAP.

Under US GAAP, the rate actions of a regulator can provide reasonable assurance of the existence of an asset (ASC 980-340-25-1), meaning that approval by the BCUC for recovery in rates results in items that would otherwise be expensed being recognized in deferral accounts for financial reporting purposes.

For plant under construction, ASC 980-360-25-1 states that "*ASC 980 requires WACC, including a designated cost of equity funds, to be capitalized in specified circumstances as part of the cost of the related asset.*"

For deferral accounts, US GAAP also allows the accounts to attract a WACC return; however, US GAAP does make the distinction that the equity component of this return would not be an allowable cost to be included in the deferral account itself (ASC 980-340-25-5). Although this is stated in US GAAP, for regulatory purposes, FEI and FBC have continued to record the full WACC return in non-rate base deferral accounts to keep them on the same footing as rate base deferral accounts with the same return.

The benefits of non-rate base deferral accounts are that they:

- Address timing issues for costs incurred or revenue received in between rate setting periods that cannot be included in forecasts (such as this one);
- Provide greater transparency into the total costs or benefits of a deferral account (as the financing is included in the deferral account itself);
- Protect ratepayers from forecast risk, as only actual costs and related actual financing costs are recorded in the deferral account (an example of this is the EEC Incentives deferral account); and

- Avoid circularity in calculations for revenue surplus or similar deferral accounts such as FEI's flow-through and earnings sharing accounts.

While US GAAP is distinct regarding the equity component of a WACC return in a deferral account, FEI believes that the use of WACC for non-rate base deferral accounts is appropriate for regulated purposes and is justified regardless of the US GAAP interpretation used for external reporting purposes. Use of a WACC rate is consistent with how the deferral account is financed by FEI, and is consistent with the return earned once transferred to rate base. Further, any potential difference between the deferral amounts reported for regulated purposes and external reporting purposes is a timing difference as, ultimately, the regulated amount which includes a full WACC return will be recovered from or returned to customers through revenue for external reporting purposes under US GAAP.

17.3.2.11 Please clarify why the deferral account will be transferred to rate base.

**Response:**

FEI has requested a non-rate base deferral account for 2020 and 2021 due to timing. Because the deferral account is not included in the rate base forecasts provided in the FEI Annual Review for 2020 and 2021 Delivery Rates, the earliest FEI can record the balance in rate base would be January 1, 2022. In the meantime, FEI would be unable to recover any amount for the financing of the deferral account. FEI will include a projected balance for the deferral account in its Annual Review for 2022 Delivery Rates.

FEI provided in Appendix A to the Evidentiary Update Status a letter from the City of Burnaby indicating that council supported the fourth route option along the Sperling Route corridor.

On page 2 of the Evidentiary Update Status, FEI states:

> …FEI has continued to progress the engineering designs for the Gaglardi Route in the event that a route in the Sperling Route corridor is determined to be not feasible or not FEI's preferred route.
>
> FEI will be completing its assessment of the feasibility of the Sperling Route corridor, including further consultation and other work needed to complete its Application in the coming weeks.

17.3.2.12 Please comment on how the City of Burnaby's support for the fourth route option along the Sperling Route corridor impacts the forecast balance of the proposed deferral account and/or the timing of when FEI proposes to commence amortization of the deferral account.

**Response:**

As discussed in the response to BCUC IR1 17.1, the Project Development costs of $2.506 million that FEI is including to the proposed deferral account are actual costs incurred by FEI up to January 31, 2020. The City of Burnaby's support for the Sperling Route occurred after January 31, 2020 and, as such, does not impact the Project Development costs that FEI is including to the proposed deferral account. Development costs incurred by FEI after January 31, 2020 are included in the Project capital costs.

17.3.2.12.1 Please provide any revisions to the forecast balance and transfer date as applicable.

**Response:**

Please refer to the response to BCUC IR1 17.3.2.12.

## D. CONSLTATION

**18.0 Reference: CONSULTATION SUMMARY**

**CPCN Guidelines, p. 6; Exhibit B-3, Section 2.7, p. 10**

**CPCN Guidelines**

The Public Consultation section of the CPCN Guidelines includes the following requirements:

> (i) Overview of the community, social and environmental setting in which the project and its feasible alternatives will be constructed and operated, and of the public who may be directly impacted by the project and its feasible alternatives.
>
> ii) Description of the information and consultation programs with the public, including the organizations, agencies and individuals consulted, the information provided to these parties, and a chronology of meetings and other communications with members of the public and their representatives. This includes consultation <u>with both the public who may be directly impacted by the project and the public that may experience impacts on their rates and service.</u> (emphasis added)

Page 10 states:

> FEI also plans to send a bill insert to all natural gas customers in the coming months upon determination of the Project scope. ... FEI will also place an advertisement on FEI's accounts online portal, which is visited by about 360,000 customers each month to pay a bill. These communications directly inform customers of the Project, including how to provide feedback and of the expected impact to rates. The Project website, email address and phone number will be maintained as an easy-to-access way for local customers, local stakeholders, and the broader public to provide FEI with feedback on the proposed routes.

18.1 Please discuss which section(s) of the Application or Exhibit B-3 provides an overview of the community, social and environmental setting as outlined by the CPCN guidelines. If an overview is not included, please confirm that this will be included in the December evidentiary update.

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

An overview of the community, social and environmental setting, as outlined by the CPCN Guidelines, was not included in the initial Application or in Exhibit B-3 given the nature of ongoing consultation and engagement regarding the Sperling routes. FEI will provide this information in its evidentiary update.

18.2 Please discuss if FEI has established what service interruptions are expected for either the Sperling or Gaglardi Routes, and what plans are in place to communicate these interruptions and identify those who will be affected.

**Response:**

FEI does not anticipate any natural gas service interruptions for either the Sperling or Gaglardi Routes. In the event natural gas service interruptions are required, FEI will proactively identify and notify those affected. Proactive notification could include direct one-on-one discussions through visits or phone calls to those affected, as well as notification letters, social media outreach and website updates.

# Attachment 1.1

FILE: 6-169-21 Attachment 1.1

A G R E E M E N T entered into this 11th day of April in the year 1957

BETWEEN -

HER MAJESTY THE QUEEN, in right of her PROVINCE OF BRITISH COLUMBIA, herein represented by the Honourable, the Minister of Highways, hereinafter called "the Province"

OF THE FIRST PART,

AND -

BRITISH COLUMBIA ELECTRIC COMPANY LIMITED ~~THE BRITISH COLUMBIA ELECTRIC CO. LTD.~~, hereinafter called the "Company".

OF THE SECOND PART.

WHEREAS the Company have requested permission of the Province to erect, maintain and operate a twenty inch steel pipe line, for the transportation of natural gas, along and under the superstructure of Pattullo Bridge across the Fraser River at New Westminster.

NOW THEREFORE THIS AGREEMENT WITNESSETH that the Province and the Company hereto agree as follows:-

1. The Province hereby grants permission to the Company to erect, maintain and operate a twenty inch steel pipe line along and under the Pattullo Bridge for the transportation of gas, as shown by plans submitted to and approved by the Department of Highways.
2. The Company may exercise the rights and privileges hereby granted for so long a time as the bridge remains a part of the highway system of the Province provided that the Minister of Highways may terminate the Agreement by giving two years notice in writing to the Company mailed to the Registered office of the Company within the Province.
3. On termination of this agreement, the Company will, within a reasonable time, remove all pipe line and attachments from the said bridge and will leave it in a condition satisfactory to the Minister of Highways.

4. The Company shall at all times hereafter save harmless and keep indemnified the Province from and against all losses, costs, expenses and damages which the Province may incur by reason of any damage or injury to persons or property arising by reason of the presence of the said pipe line passing along and under the said bridge.

5. THAT in the event of a partial or complete destruction of the bridge by any cause whatsoever which causes interference with or a complete cessation of the transmission of gas, the province shall not be held responsible for any loss of revenue which the company may incur.

6. That after receiving notice in writing of the intention of the Province to reconstruct, alter or repair the Bridge, the Company will move or alter their pipe line or cease transmission of gas, if same is necessary for the safe completion of the reconstruction, alteration or repairs. All such alterations by the Company shall be carried out at their own expense. While reasonable care will be taken by the Province to do as little damage as possible to the pipe line in carrying out the reconstruction, alterations or repairs the Province does not accept any responsibility for any damage done to the pipe line.

7. That regular inspections of the pipe line shall be carried out at times to be arranged, by an Engineer approved by the Department of Highways. Reports and finding of these inspections are to be forwarded directly to the Chief Engineer, Department of Highways, but the cost of the inspection is to be borne by the Company.

8. That the Company agrees to pay any additional insurance premium on the policy or policies carried on the Bridge which the Province may be obliged to pay by reason of the presence of the pipe line.

9. In consideration of the rights and prvileges hereby granted the Company agrees to pay to the Province the sum of Five Thousand

($5,000.00) dollars annually, payment to be made in advance to the Minister of Finance.

IN WITNESS HEREOF, the Honourable P.A. Gaglardi, Minister of Highways, has hereunto set his hand as representing Her Majesty the Queen in the right of the Province of British Columbia, and

The Company has caused to be affixed ~~its~~ Corporate Seal attested by the hands of its duly authorized officers

Signed on behalf of Province)
of British Columbia )
by Minister of Highways ) ....................................

In the Presence of........................................

Signed on behalf of ~~the~~ )
~~B.C. Electric Co. Ltd.~~) ....................................
BRITISH COLUMBIA ELECTRIC
COMPANY LIMITED

In the Presence of........................................

VICE-PRESIDENT

SECRETARY

APPROVED
as to form only
Solicitor
B. C. E. Co. Ltd.

PA-34

**THIS AGREEMENT** made as of the 16th day of July, 1988.

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY,
of 970 Burrard Street, in the City of Vancouver,
in the Province of British Columbia, V6Z 1Y3

(hereinafter referred to as the "Assignor")

OF THE FIRST PART

AND:

B.C. GAS INC., a company incorporated under
the laws of the Province of British Columbia,
of 970 Burrard Street, in the City of Vancouver,
in the Province of British Columbia, V6Z 1T3

(hereinafter referred to as the "Assignee")

OF THE SECOND PART

**WHEREAS** by asset transfer agreement entered into as of July 15, 1988 between the Assignor as vendor and the Assignee as purchaser (the "Asset Transfer Agreement") the Assignor agreed to sell and the Assignee agreed to purchase certain rights, property and assets of the Assignor, including, and without limiting the generality of the foregoing, its Gas Distribution System (the "Gas Plant") as defined in the Asset Transfer Agreement;

**WHEREAS** by various agreements made between Her Majesty the Queen in right of the Province of British Columbia, as represented by the Minister of Highways or its representative as listed in the Schedule hereto or any of its predecessors in interest (the "Grantor") and the Assignor or any of its predecessors in interest (the "Grantee"), the Grantor granted to the Grantee certain permissions in respect of the installation, operation, and maintenance of a portion of the Gas Distribution System over certain bridges within the jurisdiction of the Grantor (the "Grants");

**AND WHEREAS** pursuant to the Asset Transfer Agreement the Assignor has agreed to sell to the Assignee and the Assignee has agreed to purchase from the Assignor, inter alia, all the right, title, interest, privilege and advantage of, in and to the Grants and the agreements by which they were granted, including and without limiting the generality of the foregoing, those agreements which are more particularly set forth in the Schedule hereto (the "Agreements).

**NOW THIS AGREEMENT WITNESSETH** that in consideration of the sum of ONE DOLLAR ($1.00) and other good and valuable consideration now paid by the Assignee to the Assignor (the receipt whereof the Assignor acknowledges) the Assignor does hereby grant, assign, transfer and set over unto the Assignee, its successors and assigns, the Grants and the Agreements and all the right, title, interest, privilege and advantage thereto, therein and thereof, to have and to hold the same unto and to the use of the Assignee forever subject to the terms, covenants and conditions in the Agreements contained.

**AND** the Assignee in consideration of the premises, and for itself, its successors and assigns, promises and agrees with the Assignor, and its respective successors and assigns, that it will take the assignment of the Grants subject to all and each of the covenants and conditions therein contained and made and entered into by the Assignor in the Agreements and it will be bound by and keep and observe and perform the same in the same manner and to the same extent as if it had originally been bound by the Agreements of and from the date hereof.

**THIS AGREEMENT** shall enure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

**IN WITNESS WHEREOF** the parties hereto have hereunto affixed their corporate seals under the hands of their proper officers in that behalf on the day year first above-written.

SIGNED, SEALED and DELIVERED on behalf of BRITISH COLUMBIA HYDRO AND POWER AUTHORITY in the presence of:

A MacPherson
Name

1045 HOWE STREET
VANCOUVER, B.C.
V6Z 2B1
Address

Legal Svcs Secretary
Occupation

REGISTERED 470

APPROVED to substance
C HYDRO

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY by its Attorneys-In-Fact

SIGNED, SEALED and DELIVERED on behalf of B.C. GAS INC. in the presence of:

G. Watson
Name

1762-142 St, Sry, BC
Address

Secretary
Occupation

# Attachment 7.4

(Accessible by opening the Attachments Tab in Adobe)

# Attachment 15.2

# Cost Estimate Characterization Guidelines for Operational Assets Expenditures

# Table of Contents

# 1. SUMMARY

This document is intended to provide guidance on the required level accuracy for estimates and the purpose for which these different classes of estimates should be used. Numerical values in summary Table 1 are intended to provide direction with regards to levels of effort, cost and accuracy.

Our ability to make informed, consistent decisions depends on having a satisfactory level of accuracy for cost estimates and a companywide awareness of this classification. This guideline describes estimate classification, how estimates are used at FortisBC, the expected accuracy of estimates, and an overview of the level of effort expected to generate estimates of a given classification.

For stations, pipelines, compressors, transmission lines, electrical feeders, substations, etc. cost estimates generally fall into three different classifications, as shown in Table 1. Appendices D through K provide suggested checklists for items that should be considered when generating estimates at a given classification level.

When determining an estimate (for projects, programs, contracts, etc…), the scope should be sufficiently defined for the desired class level. For example, satisfactory stakeholder involvement is important to ensure that all required deliverables are defined and agreed upon before proceeding with cost estimating. This is to avoid "scope creep" due to unforeseen requirements. Adherence to the acceptance criteria for each class of cost estimate as defined in Table 1 is important.

# Table 1: Estimate Classification



| Estimate Class | Expected Accuracy Low | Expected Accuracy High | Purpose | Project/Technical Definition | Estimating Methodology | Horizon Years | Acceptance | Mechanism | Suggested Preparation Effort (time) | Suggested Preparation Effort |
|---|---|---|---|---|---|---|---|---|---|---|
| Class 5 **Identify** | -20% To -50% | +30% To +100% | • Long range capital funding levels<br>• Market studies<br>• Preliminary Assessments<br>• Conceptual evaluation of alternative schemes<br>• Preliminary project/concept screening | • 0 to 2%<br>• Conceptual level engineering<br>• Route/locations identified through maps<br>• Affected external stakeholders identified<br>• System parameters identified<br>• Internal Stakeholder knowledge agreement/signoff | • 'Rule of Thumb' costing<br>• Historical data<br>• Judgment based | 5 - 20 | Acknowledgment of the need | Attendance at Capital Planning Meeting, List of Projects, documented in the minutes Manager Review | Prepared with a very limited amount of time and with little effort Cost and time estimates are typically based on "expert" opinion | 0 to 0.2% of total |
| Class 4 **Evaluate** | -15% To -30% | +20% To +50% | • Detailed strategic planning<br>• Business case assessment<br>• Project screening at a more developed stage<br>• Confirmation of economic and/or technical feasibility<br>• Evaluation of alternative schemes | • 1 to 15%<br>• Pre-FEED[1] to FEED[1] level engineering<br>• Route/locations researched through land checks<br>• Affected external stakeholders identified and risk assessed<br>• System parameters defined<br>• System limitations defined<br>• Preliminary operational contingency plans identified<br>• Equipment parameters identified<br>• Major material list compiled<br>• Project schedule at concept level | • Preliminary estimate with risk conceptualized<br>• Historical data<br>• Gross unit costs<br>• Budgetary equipment and material quotes<br>• Develop construction labour and equipment crew costs | 3 - 5 | Peer Review Business Case sign -off with FEED study to support technical feasibility | Review with Engineering, PMO, Operations, Asset Management | Prepared in as little as 20 hours or less than 300 hours depending on the project | 0.1 to 1.5% of total |
| Class 3 **Define** | -10% To -20% | +10% To +30% | • Project Funding authorization<br>• First control estimate or project budget<br>• Approval to proceed to next stage or control gate | • 10 to 40%<br>• FEED[1]-level engineering<br>• Prepare Design Basis Memorandum<br>• Final route/locations defined and researched<br>• Operational contingency plans developed<br>• Non-standard equipment specifications<br>• Material list<br>• Project schedule at task level<br>• Project Execution Plan<br>• Affected stakeholders consulted and agreement reached | • Budget estimate with risk identified<br>• Budgetary equipment and material pricing<br>• Develop construction labour and equipment crew cost and incorporate in cost estimate<br>• Budgetary pricing on work components (if required) | 1 - 2 | Stakeholder Acceptance (PMO, Operations, Engineering, Lands, Planning or Asset Management) | Project charter [either PERR or Charter] (scope, schedule, cost estimate, FEED, Project acceptance form | Prepared in as little as 150 hours or less than 1500 hours depending on the project Involves more deterministic estimating methods | 1 to 4% of total |

Notes:
(1) FEED – Front End Engineering Design
(2) Approval of projects are typically Class 3 however for repetitive or program based work will often be sought on the basis of classification 4 for individual projects with the understanding that the overall program budget will be managed within +/- 10%.

## 2. BACKGROUND

On March 18, 2010, the British Columbia Utilities Commission (BCUC) published the document "2010 Certificates of Public Convenience and Necessity Application Guidelines G-50-10" ( Appendix C), which provides guidance regarding the project justification, stakeholder consultation, project scope definition and cost estimating that is required for CPCN applications. The project definition and cost estimating methodology referenced within the document is the AACE Recommended Practice No. 10S-90, Cost Engineering Terminology (Appendix A) which made reference to AACE Recommended Practice No. 18R-97 (Appendix B). In addition to adopting this methodology for its CPCN applications, FortisBC has adopted this methodology, in general concept, for its Operational Assets expenditures.

The basic premise of the methodology implemented at FortisBC is that proposed capital expenditures require different cost estimate classification, a function of project definition and the accuracy of estimate, at specific planning stages to identify, evaluate, and approve the proposed expenditure.

This document provides guidelines for applying the principles of estimate classification specifically for projects or programs to be included in the Capital Investment Plan. The objective of these guidelines is to provide common terminology and a consistent methodology for developing, understanding and implementing a project classification system to facilitate project execution.

As the core of a capital project is the physical plant and the various work components and elements, the better these are defined, the more accurate the project definition, cost estimate and schedule will be. Project definition is improved by performing engineering work, in the form of planning, front end engineering design (FEED) and detailed design, from the Identify stage through to the Define stage (see Table 1). As project definition is improved, this can be expressed as a percentage of complete project definition, the accuracy of the cost estimate can be increased. The stages of Identify, Evaluate, and Define provide increased levels of project definition and information available for developing estimates of capital cost and project schedule. As the project passes through to the next stage, there should be an improved understanding of the project and a corresponding reduction in cost and schedule uncertainty.

The Estimate Classifications in Table 1 are intended to convey the state of project definition upon which a cost estimate is based, the probable range of variation of the estimate and the purpose for which each classification class maybe used.

Estimates should therefore be a realistic attempt to reflect the extent of a project both in definition and uncertainty. It should be noted that the information supporting an estimate often relies on an extensive list of assumptions, in particularly around constructability. These assumptions are progressively refined as engineering progresses, but need to be identified and addressed at all stages.

In addition to the classification criteria outlined in Table 1, a checklist has been prepared for each asset class which can be used to confirm documentation compliance with a given classification (Appendices D to K). The purpose of the checklists is to provide guidance so that different employees with varying levels of experience can create the documentation and estimate to support the proper class with similar results. There is one checklist for each classification within each asset class. Each checklist has the requirements that are asset class specific. Allowance for risk, contingency, and other allowances need to be specifically addressed.

Historically, estimates were an educated guess based on past expenditures and experience with the work being done. Uncertainty was factored in through contingency or adjusting the values of a particular task. Looking forward, as it is difficult to identify and factor in all possible scenarios, we will be taking an approach by which we will determine the cost of the work with a risk factor to determine the potential high end of the work. All projects are to have an estimate which would contain the base estimate and contingency.

# APPENDIX A – TERMS

# APPENDIX B – AACE GUIDELINES

# APPENDIX C – BCUC ORDER G-50-10

# APPENDIX D – ELECTRIC TRANSMISSION 'CHECKLIST'

# APPENDIX D – ELECTRIC DISTRIBUTION ‘CHECKLIST’

# APPENDIX F – GENERATION 'CHECKLIST'

# APPENDIX G – ELECTRIC STATION ‘CHECKLIST’

# APPENDIX H – TRANSMISSION PIPELINE ‘CHECKLIST’

# APPENDIX I – GAS PRESSURE CONTROL & MEASUREMENT STATION ‘CHECKLIST’

# APPENDIX J – LNG ‘CHECKLIST’

# APPENDIX K – TELECOMMUNICATIONS ‘CHECKLIST’

## Cost Estimate

A prediction of quantities, cost, and/or price of resources required by the scope of an asset investment option, activity, or project. As a prediction, an estimate must address risks and uncertainties. Estimates are used primarily as inputs for budgeting, cost or value analysis, decision making in business, asset and project planning, or for project cost and schedule control processes. Cost estimates are determined using experience and calculating and forecasting the future cost of resources, methods, and management within a scheduled time frame.

## Escalation

The provision in actual or estimated costs for an increase in the cost of equipment, material, labor, etc., over that specified in the purchase order or contract due to continuing price level changes over time. Inflation may be a component of escalation, but non-monetary policy influences, such as supply-and-demand, are often components.

## Contingency (AACE)

AACE International, the Association for the Advancement of Cost engineering, has defined contingency as "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience. Contingency usually excludes:

1. Major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or project;
2. Extraordinary events such as major strikes and natural disasters;
3. Management reserves; and
4. Escalation and currency effects.

Some of the items, conditions, or events for which the state, occurrence, and/or effect is uncertain include, but are not limited to, planning and estimating errors and omissions, minor price fluctuations other than general escalation), design developments and changes within the scope, and variations in market and environmental conditions. Contingency is generally included in most estimates, and **is expected to be expended**".

## Project

Based on commonly used Project Management terminology, Project's definition is as follow: *"A temporary endeavor with a specific objective to be met within the* *prescribed time and monetary limitations and which has been assigned for definition or* Project Cost Estimating Guidelines Procedure #CRC-001 Rev. 2 **April, 27th 2009 Page 5 | 20** *execution" (AACE / PMI).* Regional Transmission projects are typically defined by the transmission owner as a result of the solution study. Projects are broken down by components in the RSP listing (Lines & Substations) but are typically permitted and reviewed as a whole for efficiency and resource/costs savings.

**Project Scope**

The sum of all that is to be or has been invested in and delivered by the performance of an activity or project. In project planning, the scope is usually documented (i.e., the scope document).

**Change in Scope**

A change in the defined deliverables or resources used to provide them.

**Level of Project Definition**

This characteristic is based upon percent complete of project definition (roughly corresponding to percent complete of engineering). The level of project definition defines maturity or the extent and types of input information available to the estimating process. Such inputs include project scope definition, requirements documents, specifications, project plans, drawings, calculations, learnings from past projects, reconnaissance data, and other information that must be developed to define the project.

**Risk Sources**

Events or conditions that have been defined for use in Risk Assessment that might affect the outcome of a project. Risk sources are frequently subdivided into the following groups, based on the underlying source of the source: 1) Business needs risks; 2) Results definition risks; 3) Scope definition risks; 4) Execution plan, mastery and processes risks; and 5) External risks.

**Risk Types**

A means of characterizing risk for use in risk assessment by the type of risk:

1. Inherited -derived from preceding stages of project;
2. Economic - associated with availability and costs of resources;
3. Commercial - associated with customer's needs and wants, competition, etc.;

4. Technological - associated with ability to achieve desired results, produce products, etc. life of current or new technology and compatibility of new technologies;
5. Implementation - ability to meet project plan and commitments due to human behavior or organizational factors.

AACE International Recommended Practice No. 18R-97

# COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

**Acknowledgments:**
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AACE International Recommended Practice No. 18R-97

# COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

February 2, 2005

## PURPOSE

As a recommended practice of AACE International, the Cost Estimate Classification System provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The Cost Estimate Classification System maps the phases and stages of project cost estimating together with a generic maturity and quality matrix, which can be applied across a wide variety of industries.

This addendum to the generic recommended practice provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries. This addendum supplements the generic recommended practice (17R-97) by providing:

- a section that further defines classification concepts as they apply to the process industries;
- charts that compare existing estimate classification practices in the process industry; and
- a chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic standard, an intent of this addendum is to improve communications among all of the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the process industries.

It is understood that each enterprise may have its own project and estimating processes and terminology, and may classify estimates in particular ways. This guideline provides a generic and generally acceptable classification system for process industries that can be used as a basis to compare against. It is hoped that this addendum will allow each user to better assess, define, and communicate their own processes and standards in the light of generally-accepted cost engineering practice.

## INTRODUCTION

For the purposes of this addendum, the term process industries is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) as primary scope defining documents. These documents are key deliverables in determining the level of project definition, and thus the extent and maturity of estimate input information.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this addendum may apply to portions of other industries, such as pharmaceutical, utility, metallurgical, converting, and similar industries. Specific addendums addressing these industries may be developed over time.

This addendum specifically does not address cost estimate classification in nonprocess industries such as commercial building construction, environmental remediation, transportation infrastructure, "dry" processes such as assembly and manufacturing, "soft asset" production such as software development, and similar industries. It also does not specifically address estimates for the exploration, production, or transportation of mining or hydrocarbon materials, although it may apply to some of the intermediate processing steps in these systems.

The cost estimates covered by this addendum are for engineering, procurement, and construction (EPC) work only. It does not cover estimates for the products manufactured by the process facilities, or for research and development work in support of the process industries. This guideline does not cover the significant building construction that may be a part of process plants. Building construction will be covered in a separate addendum.

This guideline reflects generally-accepted cost engineering practices. This addendum was based upon the practices of a wide range of companies in the process industries from around the world, as well as published references and standards. Company and public standards were solicited and reviewed by the AACE International Cost Estimating Committee. The practices were found to have significant commonalities that are conveyed in this addendum.

## COST ESTIMATE CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES

The five estimate classes are presented in figure 1 in relationship to the identified characteristics. Only the level of project definition determines the estimate class. The other four characteristics are secondary characteristics that are generally correlated with the level of project definition, as discussed in the generic standard. The characteristics are typical for the process industries but may vary from application to application.

This matrix and guideline provide an estimate classification system that is specific to the process industries. Refer to the generic standard for a general matrix that is non-industry specific, or to other addendums for guidelines that will provide more detailed information for application in other specific industries. These will typically provide additional information, such as input deliverable checklists to allow meaningful categorization in those particular industries.

| | ***Primary Characteristic*** | ***Secondary Characteristic*** | | | |
|---|---|---|---|---|---|
| **ESTIMATE CLASS** | **LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition | **END USAGE** Typical purpose of estimate | **METHODOLOGY** Typical estimating method | **EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a] | **PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b] |
| **Class 5** | 0% to 2% | Concept Screening | Capacity Factored, Parametric Models, Judgment, or Analogy | L: -20% to -50%<br>H: +30% to +100% | 1 |
| **Class 4** | 1% to 15% | Study or Feasibility | Equipment Factored or Parametric Models | L: -15% to -30%<br>H: +20% to +50% | 2 to 4 |
| **Class 3** | 10% to 40% | Budget, Authorization, or Control | Semi-Detailed Unit Costs with Assembly Level Line Items | L: -10% to -20%<br>H: +10% to +30% | 3 to 10 |
| **Class 2** | 30% to 70% | Control or Bid/ Tender | Detailed Unit Cost with Forced Detailed Take-Off | L: -5% to -15%<br>H: +5% to +20% | 4 to 20 |
| **Class 1** | 50% to 100% | Check Estimate or Bid/Tender | Detailed Unit Cost with Detailed Take-Off | L: -3% to -10%<br>H: +3% to +15% | 5 to 100 |

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

**Figure 1. – Cost Estimate Classification Matrix for Process Industries**

## CHARACTERISTICS OF THE ESTIMATE CLASSES

The following charts (figures 2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the process industries. They are presented in the order of least-defined estimates to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class.

For each chart, the following information is provided:

- **Description:** a short description of the class of estimate, including a brief listing of the expected estimate inputs based on the level of project definition.
- **Level of Project Definition Required:** expressed as a percent of full definition. For the process industries, this correlates with the percent of engineering and design complete.
- **End Usage:** a short discussion of the possible end usage of this class of estimate.
- **Estimating Methods Used:** a listing of the possible estimating methods that may be employed to develop an estimate of this class.
- **Expected Accuracy Range:** typical variation in low and high ranges after the application of contingency (determined at a 50% level of confidence). Typically, this results in a 90% confidence that the actual cost will fall within the bounds of the low and high ranges.
- **Effort to Prepare:** this section provides a typical level of effort (in hours) to produce a complete estimate for a US$20,000,000 plant. Estimate preparation effort is highly dependent on project size, project complexity, estimator skills and knowledge, and on the availability of appropriate estimating cost data and tools.
- **ANSI Standard Reference (1989) Name:** this is a reference to the equivalent estimate class in the existing ANSI standards.
- **Alternate Estimate Names, Terms, Expressions, Synonyms:** this section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this Recommended Practice. The user is cautioned that an alternative name may not always be correlated with the class of estimate as identified in the chart.

| CLASS 5 ESTIMATE | |
|---|---|
| **Description:**<br>Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systemic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than an hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation.<br><br>**Level of Project Definition Required:**<br>0% to 2% of full project definition.<br><br>**End Usage:**<br>Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc. | **Estimating Methods Used:**<br>Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 5 estimates are - 20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.<br><br>**Effort to Prepare (for US$20MM project):**<br>As little as 1 hour or less to perhaps more than 200 hours, depending on the project and the estimating methodology used.<br><br>**ANSI Standard Reference Z94.2-1989 Name:**<br>Order of magnitude estimate (typically -30% to +50%).<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb. |

**Figure 2a. – Class 5 Estimate**

<table>
<tr><th colspan="2">CLASS 4 ESTIMATE</th></tr>
<tr><td>Description:<br>Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists.<br><br>Level of Project Definition Required:<br>1% to 15% of full project definition.<br><br>End Usage:<br>Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.</td><td>Estimating Methods Used:<br>Class 4 estimates virtually always use stochastic estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques.<br><br>Expected Accuracy Range:<br>Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.<br><br>Effort to Prepare (for US$20MM project):<br>Typically, as little as 20 hours or less to perhaps more than 300 hours, depending on the project and the estimating methodology used.<br><br>ANSI Standard Reference Z94.2-1989 Name:<br>Budget estimate (typically -15% to + 30%).<br><br>Alternate Estimate Names, Terms, Expressions, Synonyms:<br>Screening, top-down, feasibility, authorization, factored, pre-design, pre-study.</td></tr>
</table>

**Figure 2b. – Class 4 Estimate**

<table>
<tr><th colspan="2">CLASS 3 ESTIMATE</th></tr>
<tr><td>Description:<br>Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists.<br><br>Level of Project Definition Required:<br>10% to 40% of full project definition.<br><br>End Usage:<br>Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase “control estimates” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate may be the last estimate required and could well form the only basis for cost/schedule control.</td><td>Estimating Methods Used:<br>Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project.<br><br>Expected Accuracy Range:<br>Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.<br><br>Effort to Prepare (for US$20MM project):<br>Typically, as little as 150 hours or less to perhaps more than 1,500 hours, depending on the project and the estimating methodology used.<br><br>ANSI Standard Reference Z94.2-1989 Name:<br>Budget estimate (typically -15% to + 30%).<br><br>Alternate Estimate Names, Terms, Expressions, Synonyms:<br>Budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, development, basic engineering phase estimate, target estimate.</td></tr>
</table>

**Figure 2c. – Class 3 Estimate**

| CLASS 2 ESTIMATE | |
|---|---|
| **Description:**<br>Class 2 estimates are generally prepared to form a detailed control baseline against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the "bid" estimate to establish contract value. Typically, engineering is from 30% to 70% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.<br><br>**Level of Project Definition Required:**<br>30% to 70% of full project definition.<br><br>**End Usage:**<br>Class 2 estimates are typically prepared as the detailed control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. | **Estimating Methods Used:**<br>Class 2 estimates always involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.<br><br>**Effort to Prepare (for US$20MM project):**<br>Typically, as little as 300 hours or less to perhaps more than 3,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.<br><br>**ANSI Standard Reference Z94.2-1989 Name:**<br>Definitive estimate (typically -5% to + 15%).<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate. |

**Figure 2d. – Class 2 Estimate**

| CLASS 1 ESTIMATE | |
|---|---|
| **Description:**<br>Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor's bid estimate, or to evaluate/dispute claims. Typically, engineering is from 50% to 100% complete, and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans.<br><br>**Level of Project Definition Required:**<br>50% to 100% of full project definition.<br><br>**End Usage:**<br>Class 1 estimates are typically prepared to form a current control estimate to be used as the final control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution. | **Estimating Methods Used:**<br>Class 1 estimates involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.<br><br>**Effort to Prepare (for US$20MM project):**<br>Class 1 estimates require the most effort to create, and as such are generally developed for only selected areas of the project, or for bidding purposes. A complete Class 1 estimate may involve as little as 600 hours or less, to perhaps more than 6,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.<br><br>**ANSI Standard Reference Z94.2 Name:**<br>Definitive estimate (typically -5% to + 15%).<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate. |

**Figure 2e. – Class 1 Estimate**

## COMPARISON OF CLASSIFICATION PRACTICES

Figures 3a through 3c provide a comparison of the estimate classification practices of various firms, organizations, and published sources against one another and against the guideline classifications. These tables permits users to benchmark their own classification practices.

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>ANSI Standard Z94.0</th><th>AACE Pre-1972</th><th>Association of Cost Engineers (UK) ACostE</th><th>Norwegian Project Management Association (NFP)</th><th>American Society of Professional Estimators (ASPE)</th></tr>
<tr><td rowspan="3">Class 5</td><td rowspan="3">Order of Magnitude Estimate -30/+50</td><td rowspan="3">Order of Magnitude Estimate</td><td rowspan="3">Order of Magnitude Estimate Class IV -30/+30</td><td>Concession Estimate</td><td rowspan="4">Level 1</td></tr>
<tr><td>Exploration Estimate</td></tr>
<tr><td>Feasibility Estimate</td></tr>
<tr><td rowspan="2">Class 4</td><td rowspan="4">Budget Estimate -15/+30</td><td rowspan="2">Study Estimate</td><td rowspan="3">Study Estimate Class III -20/+20</td><td rowspan="2">Authorization Estimate</td></tr>
<tr><td rowspan="2">Level 2</td></tr>
<tr><td rowspan="2">Class 3</td><td rowspan="2">Preliminary Estimate</td><td rowspan="2">Master Control Estimate</td></tr>
<tr><td>Budget Estimate Class II -10/+10</td><td>Level 3</td></tr>
<tr><td rowspan="2">Class 2</td><td rowspan="4">Definitive Estimate -5/+15</td><td rowspan="2">Definitive Estimate</td><td rowspan="4">Definitive Estimate Class I -5/+5</td><td rowspan="4">Current Control Estimate</td><td>Level 4</td></tr>
<tr><td rowspan="2">Level 5</td></tr>
<tr><td rowspan="2">Class 1</td><td rowspan="2">Detailed Estimate</td></tr>
<tr><td>Level 6</td></tr>
</table>

**Figure 3a. – Comparison of Classification Practices**

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>Major Consumer Products Company (Confidential)</th><th>Major Oil Company (Confidential)</th><th>Major Oil Company (Confidential)</th><th>Major Oil Company (Confidential)</th></tr>
<tr><td rowspan="2">Class 5</td><td rowspan="2">Class S<br>Strategic Estimate</td><td rowspan="2">Class V<br>Order of Magnitude Estimate</td><td>Class A<br>Prospect Estimate</td><td rowspan="2">Class V</td></tr>
<tr><td>Class B<br>Evaluation Estimate</td></tr>
<tr><td rowspan="2">Class 4</td><td rowspan="2">Class 1<br>Conceptual Estimate</td><td rowspan="2">Class IV<br>Screening Estimate</td><td>Class C<br>Feasibility Estimate</td><td rowspan="2">Class IV</td></tr>
<tr><td rowspan="2">Class D<br>Development Estimate</td></tr>
<tr><td rowspan="3">Class 3</td><td rowspan="3">Class 2<br>Semi-Detailed Estimate</td><td rowspan="2">Class III<br>Primary Control Estimate</td><td rowspan="2">Class III</td></tr>
<tr><td rowspan="2">Class E<br>Preliminary Estimate</td></tr>
<tr><td rowspan="2">Class II<br>Master Control Estimate</td><td rowspan="2">Class II</td></tr>
<tr><td>Class 2</td><td rowspan="2">Class 3<br>Detailed Estimate</td><td>Class F<br>Master Control Estimate</td></tr>
<tr><td>Class 1</td><td>Class I<br>Current Control Estimate</td><td>Current Control Estimate</td><td>Class I</td></tr>
</table>

**Figure 3b. – Comparison of Classification Practices**

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>J.R. Heizelman, 1988 AACE Transactions [1]</th><th>K.T. Yeo, The Cost Engineer, 1989 [2]</th><th>Stevens & Davis, 1988 AACE Transactions [3]</th><th>P. Behrenbruck, Journal of Petroleum Technology, 1993 [4]</th></tr>
<tr><td>Class 5</td><td>Class V</td><td>Class V<br>Order of Magnitude</td><td>Class III*</td><td>Order of Magnitude</td></tr>
<tr><td>Class 4</td><td>Class IV</td><td>Class IV<br>Factor Estimate</td><td rowspan="4">Class II</td><td rowspan="2">Study Estimate</td></tr>
<tr><td rowspan="2">Class 3</td><td rowspan="2">Class III</td><td rowspan="2">Class III<br>Office Estimate</td></tr>
<tr><td rowspan="2">Budget Estimate</td></tr>
<tr><td>Class 2</td><td>Class II</td><td>Class II<br>Definitive Estimate</td></tr>
<tr><td>Class 1</td><td>Class I</td><td>Class I<br>Final Estimate</td><td>Class I</td><td>Control Estimate</td></tr>
</table>

[1] John R. Heizelman, ARCO Oil & Gas Co., 1988 AACE Transactions, Paper V3.7
[2] K.T. Yeo, The Cost Engineer, Vol. 27, No. 6, 1989
[3] Stevens & Davis, BP International Ltd., 1988 AACE Transactions, Paper B4.1 (* Class III is inferred)
[4] Peter Behrenbruck, BHP Petroleum Pty., Ltd., article in Petroleum Technology, August 1993

**Figure 3c. – Comparison of Classification Practices**

 

## ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Figure 4 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the process industries. The maturity level is an approximation of the degree of completion of the deliverable. The degree of completion is indicated by the following letters.

- None (blank): development of the deliverable has not begun.
- Started (S): work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): the deliverable has been reviewed and approved as appropriate.

| | ESTIMATE CLASSIFICATION | | | | |
|---|---|---|---|---|---|
| **General Project Data:** | **CLASS 5** | **CLASS 4** | **CLASS 3** | **CLASS 2** | **CLASS 1** |
| Project Scope Description | General | Preliminary | Defined | Defined | Defined |
| Plant Production/Facility Capacity | Assumed | Preliminary | Defined | Defined | Defined |
| Plant Location | General | Approximate | Specific | Specific | Specific |
| Soils & Hydrology | None | Preliminary | Defined | Defined | Defined |
| Integrated Project Plan | None | Preliminary | Defined | Defined | Defined |
| Project Master Schedule | None | Preliminary | Defined | Defined | Defined |
| Escalation Strategy | None | Preliminary | Defined | Defined | Defined |
| Work Breakdown Structure | None | Preliminary | Defined | Defined | Defined |
| Project Code of Accounts | None | Preliminary | Defined | Defined | Defined |
| Contracting Strategy | Assumed | Assumed | Preliminary | Defined | Defined |
| **Engineering Deliverables:** | | | | | |
| Block Flow Diagrams | S/P | P/C | C | C | C |
| Plot Plans | | S | P/C | C | C |
| Process Flow Diagrams (PFDs) | | S/P | P/C | C | C |
| Utility Flow Diagrams (UFDs) | | S/P | P/C | C | C |
| Piping & Instrument Diagrams (P&IDs) | | S | P/C | C | C |
| Heat & Material Balances | | S | P/C | C | C |
| Process Equipment List | | S/P | P/C | C | C |
| Utility Equipment List | | S/P | P/C | C | C |
| Electrical One-Line Drawings | | S/P | P/C | C | C |
| Specifications & Datasheets | | S | P/C | C | C |
| General Equipment Arrangement Drawings | | S | P/C | C | C |
| Spare Parts Listings | | | S/P | P | C |
| Mechanical Discipline Drawings | | | S | P | P/C |
| Electrical Discipline Drawings | | | S | P | P/C |
| Instrumentation/Control System Discipline Drawings | | | S | P | P/C |
| Civil/Structural/Site Discipline Drawings | | | S | P | P/C |

**Figure 4. – Estimate Input Checklist and Maturity Matrix**

## REFERENCES

ANSI Standard Z94.2-1989. **Industrial Engineering Terminology: Cost Engineering**.
AACE International Recommended Practice No.17R-97, **Cost Estimate Classification System**.

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Bernard A. Pietlock, CCC
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Don L. Short, II

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-50-10

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IN THE MATTER OF
The Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and
2010 Certificates of Public Convenience and Necessity Application Guidelines

**BEFORE:** L.F. Kelsey, Commissioner
D.A. Cote, Commissioner March 18, 2010

**O R D E R**

**WHEREAS:**

A. The *Utilities Commission Act* (the Act) states in section 46(1) that an applicant for a Certificate of Public Convenience and Necessity (CPCN) must file with the British Columbia Utilities Commission (the Commission) information, material, evidence and documents that the Commission prescribes; and

B. On March 31, 2004 the Commission, by Order G-28-04, issued its "Guidelines for CPCN Applications" which established the required procedure and information for CPCN applications under the Act; and

C. On September 16, 2009, the Commission issued draft 2009 CPCN Application Guidelines for a 60-day comment period from regulated utilities and the public; and

D. Comments were received from British Columbia Hydro and Power Authority , British Columbia Transmission Corporation, FortisBC Inc., Pacific Northern Gas Ltd., Skeetchestn Indian Band and Terasen Utilities; and

E. The Commission has reviewed the comments and considers that the establishment of the 2010 CPCN Application Guidelines is warranted.

**NOW THEREFORE** the Commission orders as follows:

1. Commission Order G-28-04 is cancelled.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-50-10



2. An application for a CPCN pursuant to sections 45 and 46 of the Act is to be made in a form that satisfies the requirements outlined in Appendix A to this Order.

**DATED** at the City of Vancouver, in the Province of British Columbia, this 18th day of March 2010.

BY ORDER

*Original signed by:*

D.A. Cote
Commissioner

Attachment

**APPENDIX A**
to Order G-50-10

# *British Columbia Utilities Commission*

# *2010 Certificates of Public Convenience and Necessity Application Guidelines*

# TABLE OF CONTENTS

**PURPOSE AND SCOPE OF GUIDELINES**

The purpose of these guidelines is to assist public utilities and other parties wishing to construct or operate utility facilities in preparing their applications for a Certificate of Public Convenience and Necessity (CPCN) so the review of these applications by the British Columbia Utilities Commission (Commission) can proceed as efficiently as possible. The Commission expects CPCN applications will generally be prepared in accordance with the guidelines.

Section 45(1) of the Utilities Commission Act (UCA) requires that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the Commission a CPCN approving the construction or operation. Section 46(1) of the UCA requires an application for a CPCN be filed with Commission.

A copy of the UCA can be found at http://www.qp.gov.bc.ca/statreg/stat/U/96473_01.htm

The guidelines do not alter the fundamental regulatory relationship between utilities and the Commission. They provide general guidance regarding the Commission's expectations of the information that should be included in CPCN applications while providing the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project, and the issues that it raises. An applicant is expected to apply the guidelines in a flexible and reasonable manner. The Commission may issue further directions relating to the information to be included in specific CPCN applications and may require applicants to provide further information to supplement material in filed applications.

CPCN applications may be supported by long-term resource plans filed under section 44.1 of the UCA. These long-term resource plans may deal with significant aspects of project justification, particularly the need for the project and the assessment of the overall costs and benefits of the project and alternatives to the project. Under section 44.1(9) of the UCA, in approving a long-term resource plan, the Commission may order that a proposed utility plant or system, or an extension of either, is exempt from the requirements of section 45(1) of the UCA.

Public utilities and other project proponents are encouraged to initiate discussions with appropriate government agencies and consult with the public and potentially affected First Nations as early as possible in the planning and design phase of a project in order to gain an understanding of the issues to be addressed prior to the filing of an application.

**DEEMED CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY**

Sections 45(2), 45(5) and 45(6) of the UCA state:

> (2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it:
>
> > (a) to operate the plant or system; and
> > (b) subject to subsection (5), to construct and operate extensions to the plant or system.
>
> (5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.
>
> (6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.

In order to evaluate whether a public utility should apply for a CPCN for a specific extension to a utility plant or system and therefore whether to make an order pursuant to section 45(5), the Commission needs to be aware of planned extensions that are significant. This information is provided in the statement of planned extensions that a public utility is required to file at least once a year. The statement should be filed in a timely fashion and should identify each discrete extension to a utility plant or system that may have a material impact on customer rates or raise some other significant issue. The statement should include all extensions that the utility is likely to initiate over the period until the filing of the next statement on extensions, and should use a definition of extension that is as broad and inclusive as possible. A utility should inform the Commission in the event it plans to initiate a significant extension that was not identified in its most recent statement on extensions.

A long-term resource plan filed pursuant to section 44.1 of the UCA or a capital expenditure schedule filed pursuant to section 44.2(1)(b) may meet the requirements of section 45(6) provided it is filed prior to the start of the construction of the extensions. Also, section 45(4) provides that the Commission may, by regulation, exclude utility plant or categories of utility plant from the operation of section 45(1). Under this provision, the Commission may establish project thresholds relating to size, production capacity, type and absence of local impacts that will determine projects that would generally not require a CPCN application.

## PROCEDURAL CONSIDERATIONS

An application for a CPCN pursuant to sections 45 and 46 of the UCA will be made to the Secretary of the Commission. Applications are to be filed in accordance with the Commission's document filing protocols. A text recognizable and bookmarked electronic copy with working spreadsheets and 12 hard copies of the completed and signed CPCN application should be submitted. Applications are typically made public, except where special circumstances require confidentiality.

The filed application is initially reviewed by the Commission for possible deficiencies and any additional information is requested through an information request which is responded to by the applicant. Once the response to the information request is received, the application is reviewed by the Commission to understand the application, identify any additional deficiencies, and make a preliminary determination as to whether a hearing is required, and if required, the nature of the proceeding. Pursuant to section 46(2), the Commission may establish an oral or written hearing and regulatory timetable if further review of the application is required.

The Commission makes a determination on disposition of the CPCN application as follows:

- (a) Grant a CPCN without further input from the applicant or other interested parties.
- (b) Require further information from the applicant.
- (c) Set down an oral or written public hearing.
- (d) Deny the application.

Approval of a CPCN application results in the Commission issuing an order to the applicant granting the CPCN. The order may include terms and conditions which the Commission believes the public convenience or necessity require.

For further information, contact:

Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Telephone: (604) 660-4700
Toll Free: 1-800-663-1385
Facsimile: (604) 660-1102
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

# APPLICATION REQUIREMENTS

An application under sections 45 and 46 of the UCA should contain the following information:

1. Applicant

(i) Name, address and description of the nature of the applicant's business and all other persons having a direct interest in project ownership or management;

(ii) Evidence of the financial and technical capacity of the applicant and other persons involved, if any, to undertake and operate the project;

(iii) Name, title and address of the person with whom communication should be made respecting the application;

(iv) Name and address of legal counsel for the applicant, if any;

(v) Organizational chart of the project team, including the names of the Project Manager and Executive Sponsor for the project; and

(vi) Outline of the regulatory process the applicant recommends for the Commission's review of the application, including how persons who were consulted about the project can raise outstanding application-related concerns with the Commission.

2. Project Need, Alternatives and Justification

(i) Studies or summary statements identifying the need for the project and confirming the technical, economic and financial feasibility of the project, identifying assumptions, sources of data, and feasible alternatives considered. The applicant should identify alternatives that it deemed to be not feasible at an early screening stage, and provide the reason(s) why it did not consider them further;

(ii) A comparison of the costs, benefits and associated risks of the project and feasible alternatives, including estimates of the value of all of the costs and benefits of each option or, where these costs and benefits are not quantifiable, identification of the cost or benefit that cannot be quantified. Cost estimates used in the economic comparison should have, at a minimum, a Class 4[1] degree of accuracy as defined in the Advancement of Cost Engineering ("AACE International") Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009);

(iii) A schedule calculating the revenue requirements of the project and feasible alternatives, and the resulting impacts on customer rates;

(iv) A schedule calculating the net present values of the incremental cost and benefit cash flows of the project and feasible alternatives, and justification of the length of the term and discount rate used for the calculation;

(v) A schedule and supporting discussion comparing the project and feasible alternatives in terms of social and environmental factors, and the applicant's assessment regarding the overall social and environmental impact of the project relative to the overall impact of the feasible alternatives; and

(vi) Information relating the project to the applicant's approved long-term resource plan filed pursuant to section 44.1 of the UCA, including the extent to which the project was considered in the plan, and, if applicable, a discussion explaining how the plan provides support and justification for the need for the project.

[1] Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval.

3. Consultation

First Nations Consultation

| |
|---|
| Note: Crown utilities are required to provide the information requirements set out in the British Columbia Utilities Commission 2010 First Nations Information Filing Guidelines for Crown Utilities, which replace and supersede the application requirements in this First Nations Consultation section of the CPCN Application Guidelines. |

If an applicant is of the view that the application does not require consultation with First Nations, reasons supporting its conclusion should be provided to the Commission. Unless otherwise justified, the following information should be filed:

(i) Identification of the First Nations potentially affected by the application or filing, including the feasible project alternatives; and the information considered to identify these First Nations.

For each potentially affected First Nation, summarize the consultation to date, including:

(ii) Identification of any group, body, specific band or specific person(s) that have been consulting on behalf of the First Nation in connection with the application. Identify the specific member bands represented by any group or body;

(iii) A chronology of meetings, other communications and actions;

(iv) Any relevant, non-confidential written documentation regarding consultation, such as notes or minutes of meetings or phone calls, or letters received from or sent to the First Nation;

(v) Identification of specific issues or concerns raised by the First Nation;

(vi) Description of how the specific issues or concerns raised by the First Nation were avoided, mitigated or otherwise accommodated; or explain why no further action is required to address an issue or concern;

(vii) Copies of any documents which confirm that the First Nation is satisfied with the consultation to date;

(viii) Evidence that the First Nation has been notified of the filing of the application with the Commission and has been informed on how to raise outstanding concerns with the Commission; and

(ix) The applicant's overall view as to the sufficiency of the consultation process with the First Nation to date, in the context of the decision which is being sought from the Commission.

<u>Public Consultation</u>

(i) Overview of the community, social and environmental setting in which the project and its feasible alternatives will be constructed and operated, and of the public who may be directly impacted by the project and its feasible alternatives;

(ii) Description of the information and consultation programs with the public, including the organizations, agencies and individuals consulted, the information provided to these parties, and a chronology of meetings and other communications with members of the public and their representatives. This includes consultation with both the public who may be directly impacted by the project and the public that may experience impacts on their rates and service;

(iii) Description of the issues and concerns raised during consultations, the measures taken or planned to address issues or concerns, or an explanation of why no further action is required to address an issue or concern;

(iv) Identification of any outstanding issues or concerns; and

(v) Applicant's overall assessment as to the sufficiency of the public consultation process with respect to the project, in the context of the decision which is being sought from the Commission.

4. Project Description

(i) Description of the project, its purpose and cost, including engineering design, capacity, location options and preference, safety and reliability considerations, and all ancillary or related facilities that are proposed to be constructed, owned or operated by the applicant;

(ii) Outline of the anticipated construction and operation schedule, including critical dates of key events, a chart of major activities showing the critical path (e.g., GANTT[2] chart), and the timing of approvals required from other agencies to ensure continued economic viability;

(iii) Description of any new or expanded public works, undertakings or infrastructure that will result from or be required by the project, and an estimate of the costs and necessary completion dates;

(iv) Human capital resources required to undertake the project;

(v) Risk analysis identifying all significant risks to successful completion of the project, including an assessment of the probability of each risk occurring, and the consequences and the cost to mitigate the risk;

(vi) Identification and preliminary assessment of potential effects of the project on the physical, biological and social environments or on potentially affected First Nations and the public, proposals for reducing potentially negative effects and maximizing benefits from positive effects, and the cost to the project of implementing the proposals;

(vii) Identification of the customers to be served by the project and, where the project would expand the area served by the applicant, a geographical description of the expanded service area;

[2] GANTT chart is a bar chart which illustrates a project schedule.

(viii) List of all required federal, provincial and municipal approvals, permits, licenses or authorizations; and

(ix) Summary of the material conditions that are anticipated in federal, provincial and municipal approvals and confirmation that the costs of complying with these conditions are included in the cost estimate in the application.

5. Project Cost Estimate

(i) Project cost estimate, including a description of the method of estimating used, the percentage of engineering completed at the time of the estimate, and identification and justification of all assumptions, exclusions, inflation and discount factors, and sources of benchmarks and other data;

(ii) The cost estimate should be stated in nominal as well as real dollars, identify an expected accuracy range and have, at a minimum, a Class 3[3] degree of accuracy as defined in AACE International Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009);

(iii) The cost estimate should provide:

(a) Any funds spent in prior years attributable to the project;
(b) A list of all project direct and indirect costs using a work breakdown structure by year until completion;
(c) Escalation (including inflation) amounts;
(d) Contingency amount;
(e) Interest during construction or allowance for funds used during construction and corporate overhead;
(f) Identification and explanation of any management or other reserves;

[3] Class 3 estimates are typically prepared to support full project funding requests, and become the first project phase “control estimate” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates.

(g) Any legal, regulatory and other non-project costs, including costs associated with First Nations and public consultation and accommodation.

(iv) Identification of any cost items not included in the estimate, including transportation costs, and the reason for the exclusion; and

(v) If a Monte Carlo[4] analysis was used to model and back-up the amount of project contingency included in the cost estimate, the base estimate, P50 expected value estimate, P90 estimate, histogram and cumulative curves, and tornado graphs.

6. <u>Provincial Government Energy Objectives and Policy Considerations</u>

(i) Discuss how the project is consistent with and will advance the government's energy objectives as set out in the UCA. If the nature of the project precludes a direct link to the energy objectives, the application should discuss how the project does not hamper other projects or initiatives undertaken by the applicant or others, from advancing these energy objectives;

(ii) Discuss how the project relates to and supports the Province's electricity self-sufficiency goals as set out in 64.01 of the UCA or as set out in Special Direction No. 10 to the Commission, if applicable; and

(iii) Where the applicant is BC Hydro or a prescribed public utility, discuss how the project relates to and supports the Province's clean and renewable electricity goal as set out in 64.02 of the UCA, if applicable.

7. <u>New Service Areas</u>

(i) Telephone number or other means by which customers will be able to contact the utility, particularly regarding an emergency;

(ii) Description of facilities and trained personnel that will provide emergency response;

[4] Monte Carlo analysis involves using random numbers and probability to solve problems.

(iii) Tariff including terms and conditions of service, rate schedules and initial rates the applicant proposes for customers in the new service area; and

(iv) Information confirming the proposed rates will be competitive with other service options that are available to customers in the new service area.

# Distribution Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

## *Distribution*

Project class definitions and documentation required.

## *Class 5* (Identify)

## Required Documentation

❒Capital Planning Initiation Document (CPID) containing:

- Planning Project Definition:
  - From problem /opportunity project definition developed (progress into scope document)
- Schedule:
  - -Duration 1, 2 or 3 or more Years
  - -Year to be completed
- Goals
- Project Components
  - -Identify distribution feeder, voltage and conductor ampacity
- Justification Needs/Requirements
- Operational Problems: From SCC Outage Reports
  - Load information
- Options
  - List of options to be looked at with high level costs
- System SLD:
  - Feeder routes, isolation points, taps and major equipment only
- Assumptions
  - List of assumptions used in estimate that effects cost of project
- Planning System Documentation
  - High Level Cost
  - Planning Study
- Sign Off: PMO, Planning, Engineering, Operations

❒Class 5 Estimate

- Produced from Planning Estimate
- Corporate financials are calculated and added to base estimate

❒Risks Assessment (high Level)

- Identify risks associated with the project

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

***Class 4*** (Evaluate)

## Required Documentation

❐Business case (with all options) containing:

- Project Cost
- Description of the Project
- Key Drivers
- In-Service Date, Construction Start Date
- Implications of Deferral
- Financial Impact
  - Estimated Capital Cost and Accuracy of Estimate
  - Operating Cost Impact
  - Recognize impact and other areas of FBC
- Options
  - Pros and Cons as well as the impacts on DSM
  - Final Route
- Related Projects
  - Timing and staging considerations
- Risks/Other Considerations
- Documentation Check List
  - Load Flow Values
  - Voltage Records
  - Customer information
  - Reliability Analysis
  - Zoning consideration
  - Coordination with other utilities if required
  - Identify if Survey and Geotechnical studies are required budget and approved
  - Sign Off: PMO, Planning, Engineering, Operations

❐ Class 4 Estimate

- Preliminary SLD
- Evaluate route plan options and recommend a Preferred Route Plan with possible structure locations
- Legal Plan acquired, ROW boundaries
- Preliminary Structure types determined
- Major Material List
- If required Preliminary Profile based on Government terrain models
- If required Preliminary Survey and Geotechnical Data
- Corporate financials are calculated and added to base estimate

❐ Preliminary Schedule and Construction Plan

- Engineering, Construction and Commissioning schedules are determined
- Starting quarter and ending quarter identified
- Identify construction constrains including weather, remote location switching request

❐Risks Assessment (for each option)

- Identify risks associated with the project at this level

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

***Class 3*** (Define)

## Required Documentation

❒ Business Case (preferred option chosen, justification)

❒Class 3 Estimate

- Produced from Class Estimate 4 FortisBC Designer Workbook
- Approved SLD
- Material list complete, long lead materials finalized
- Preferred Route Plan
- Possible Structure Locations for Preferred Route Plan
- Define structure types, main equipment size/locations, etc
- If required Survey Data Complete
- If required Geotechnical data Complete
- ROW requirement identified (budget costs set
  If required:
  - Land rights (private land, crown land)
  - First Nations approval
  - Ministry of Environment approval
  - Municipal or Regional permitting
  - Railways approval
- Corporate financials are calculated and added to base estimate

❒Approved Construction Plan and Schedule

- Contingency plan including switching plan if need it

❒Risks Assessment for preferred option

- Identify risks associated with the project at this level

❒Preliminary Budget Set

The schedule and estimate should be located in the specific folder on SharePoint Site

Once sign-offs are complete, the project can proceed to the Class 2 classification.

***Class 2*** (Control)

Part of Project Management Process and therefore not defined in this document

***Class 1*** (Operate)

Part of Project Management Process and therefore not defined in this document

# *Generation Project Cost Classification System*

(Based on the AACE International Recommend Practice No. 18R-97)

## *Generation*

Project class definitions and documentation required.

***Class 5*** (Identify)

### Required Documentation

❒Planning Initiation Document (CPID)
- Explanation of problem/opportunity
- Initiated for every project

❒Options Review
- Produced from Generation Preliminary Planning Approval Templates
- Risks Identified
- Major equipment
- Operation problems identified

❒Scope document
- Produced from Generation Scope Template
- Based on preferred option
- Site location
- Contracting out requirement.
- Plant or Unit Outage requirement
- Project Battery Limits

❒Project Rating – Generation Internal
- Produced from Generation Rating Template
- Safety, Environment, and Operational risks
- Used to determines approximate year in which project will be installed
- Used to determine estimate class requirement at this time

❒Class 5 Estimate
- Produced from Generation Estimate Templates
- Based on preferred option
- Assumptions
- Engineering discipline requirements
- Preliminary schedule
- Preliminary Cash Flow
- SAP historical cost information

❒Operations sign-off of complete Class 5 package

❒Planning sign-off of complete Class 5 package

❒Engineering sign-off of complete Class 5 package

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 4 classification.

***Class 4*** (Evaluate)

## Required Documentation

❒Options Approval
- Produced from Generation Preliminary Planning Approval Templates
- Option costs
- Pros and Cons of selected option clearly stated
- Operations, engineering discipline sign off

❒Planning Scope Issued
- Issued by Planning to Engineering
- Based on selected option

❒Sketches and Preliminary Lists
- Documentation will vary depending on project type, and Engineering discipline.
- Document to be signed as reviewed by Engineering discipline

Minimum sketch requirement is:
- Equipment layout.
- Equipment lists, material quantities, long term delivery items identified
- Equipment sizing, single line drawing

❒Class 4 Estimate
- Produced from Generation Estimate Sheet
- SAP Historical Cost Information
- Budgetary Vendor Quotes
- WBS (Work Breakdown Structure) as part of estimate.
- EPCM (Engineering, Procurement, Construction Management) costs and man-hours estimated
- Cost of Removal estimated
- FortisBC labor man-hours identified
- Preliminary Schedule based on WBS, will indicate as a minimum engineering, construction and commissioning schedules

❒Preliminary Work Plan
- Starting quarter and ending quarter identified
- Identify construction constraints including weather, remote location, crane requirements, access, facilities etc.

❒Business case started
- For Management/Directors approvals

❒Planning sign-off of complete Class 4 package

❒Engineering sign-off of complete Class 4 package

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 3 classification.

## *Class 3* (Define)

## Required Documentation

❒Approved Planning Scope
- Operations signoff
- SCC sign-off (as required)

❒Approved Work Plan
- Work Plan to be signed as reviewed by Operations, Engineering and SCC (if required)
- Site access
- Crane requirements and access
- On site facilities
- Management and labour resources
- Security

❒Drawings and Lists
- Documentation will vary depending on project type, and engineering discipline.
- Document to be signed as approved by engineering discipline.

Minimum Drawing Requirement:
- Equipment layout. Site Plan
- Equipment lists, material quantities, long term delivery items identified
- Equipment sizing, Single Line Drawing

❒Preliminary Specifications
- Operations signoff
- Engineering signoff

❒Approved Schedule
- Completed using MS Project
- Signoff by PMO
- Signoff by Project Engineer
- Signoff by SCC
- Signoff by Operations

❒Class 3 Estimate
- Produced from Generation Estimate Sheet
- SAP Historical Cost Information, inflation review
- Written Vendor quotes based on preliminary specification
- Confirmation of Contracting Out status

❒Preliminary Budget Set

❒Business case completed

Once sign-offs are complete, the project can proceed to the Class 2 classification.

## *Class 2* (Execute)

Part of Project Management Process and therefore not defined in this document

## *Class 1* (Operate)

Part of Project Management Process and therefore not defined in this document

# Station Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

## Station

Project class definitions and documentation required.

### *Class 5* (Identify)

### Required Documentation

❒Capital Planning Initiation Document (CPID) containing:

- Planning Project Definition:
  - From problem /opportunity project definition developed (progress into scope document)
- Schedule:
  - Duration 1, 2 or 3 or more Years
  - Year to be completed
- Goals
- Project Components
- Justification Needs/Requirements
- Operational Problems: From SCC Outage Reports
- Load information
- Options
  - List of options to be looked at with high level costs
- System SLD:
  - Lines, Feeders and Major Equipment only
- Assumptions
  - List of assumptions used in estimate that effects cost of project
- Planning System Documentation
  - High Level Cost
  - Planning Study
- Sign Off: PMO, Planning, Engineering, Operations

❒Class 5 Estimate

- Produced from Planning Station Estimate Templates
- Corporate financials are calculated and added to base estimate

❒Risks Assessment (high Level)

- Identify risks associated with the project at this level

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

## *Class 4* (Evaluate)

## Required Documentation

❒Business case (with all options) containing:

- Project Cost
- Description of the Project
- Key Drivers
- In-Service Date, Construction Start Date
- Implications of Deferral
- Financial Impact
  - Estimated Capital Cost and Accuracy of Estimate
  - Operating Cost Impact
  - Recognize impact and other areas of FBC
- Options
  - Pros and Cons as well as the impacts on DSM
  - Final Site Location
- Related Projects
  - Timing and staging considerations
- Risks/Other Considerations
- Documentation Check List
  - Load Flow Values
  - Voltage Records
  - Customer information
  - Reliability Analysis
  - Zoning consideration
  - Coordination with other utilities if required
- Sign Off: PMO, Planning, Engineering, Operations

❒ Class 4 Estimate
- Produced from Planning Station Estimate Templates

- Preliminary Comm Block
- Final Site Location
- Preliminary Site Plan
- Preliminary GA
- Preliminary Sections
- Major Material List
- Preliminary P&C Single Line
- Fault Current Study
- Impact on equipment arc flash

- Corporate financials are calculated and added to base estimate

Green Field:
- Preliminary Survey Data
- Preliminary Geotechnical Data

❒ Preliminary Schedule and Construction Plan
- Engineering, Construction and Commissioning schedules are determined
- Starting quarter and ending quarter identified
- Identify construction constrains including weather, remote location etc

❒ Risks Assessment (for each option)
- Identify risks associated with the project at this level

*Once the sign-off is complete, the project can proceed to the Class 3 Classification*

***Class 3*** (Define)

## Required Documentation

❒ Business Case (with preferred option chosen, justification)

❒ Class 3 Estimate for preferred option
- Produced from Class 4 Estimate Sheet
- Corporate financials are calculated and added to base estimate
- Approved SLD
- Approved Logics
- Material list complete
- Approved GA
- Approved Sections
- Grounding Study
  - Existing stations may have previous studies with soil resistivity measurements
- Survey Data Complete
- Geotechnical Data Complete
- Approved Comm Block Diagram
- Building Layout
- Staging Drawings completed
- Approved Site Plan
- Preliminary Conduit Plan
- Preliminary Grounding Plan
  - Is there adequate insulating gravel
  - Is there a perimeter grid

❒ Approved Schedule and Construction Plan
- Contingency plan including any by-pass installation

The schedule and estimate should be located in the specific folder on SharePoint Site

❒ Risks Assessment for preferred option
- Identify risks associated with the project at this level

❒Preliminary Budget Set

Once sign-offs are complete, the project can proceed to the Class 2 classification.

***Class 2*** (Execute)

Part of Project Management Process and therefore not defined in this document.

***Class 1*** (Operate)

Part of Project Management Process and therefore not defined in this document.

# Transmission Pipeline Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

## Transmission Pipelines

Project class definitions and documentation required.

## Class 5 (Identify)

## Required Documentation

❒ Class 5 Front End Engineering Design (FEED) containing:

- Planning Project Definition
  - Define project scope from known problem or opportunity
  - Justification, needs, and requirements
  - Relevant codes and standards
  - Permitting & Regulatory requirements
- Basis of Design
  - Design parameters
  - System Capacity Planning Documentation
- Route Location
  - Start and end points
  - Major natural obstacles
  - Major crossings
- Options
  - List of options to meet requirements
  - Google Earth sketchup with elevation
- Schedule:
  - Project duration (1, 2 or 3 years or more)
  - Year to be completed
- Assumptions:
  - List of main assumptions used in estimate that affects cost of project
  - List of clarifications used in estimate that affects cost of project
- Sign Off: Asset Management, Engineering, Operations

❒ Class 5 Cost Estimate

- Basis of Estimate
  - Estimate development
  - Benchmarked costs
  - Produced from FortisBC Workbook
- Total project cost estimate based on similar past projects

❒ Risks Assessment (high Level)

- Identify risks associated with the project at this level (eg. Permitting, scheduling, procurement, etc.)

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

***Class 4*** (Evaluate)

## Required Documentation

❒ Updated PERR FEED Request
- Confirming requirements

❒ Class 4 Front End Engineering Design (FEED) containing:
- Project Cost
- Project Description
  - Project scope
  - Key drivers
  - Relevant codes and standards
  - Financial & Operating cost Impact
  - Permitting & Regulatory requirements
  - Impacts to other areas of FBC
  - AMFM asset reference data
- Route Location
  - Start and end points
  - Major infrastructure obstacles
  - Major natural obstacles
  - Major crossings (trenchless)
- Options
  - List of options to meet requirements
  - Pros and cons of each option/proposal
  - Google Earth sketchup with elevation
  - Risk associated with each option
  - Recognize impact and other areas of FBC
- Related Projects
  - Timing and staging considerations
- Documentation Checklist
  - System Capacity Planning load calculations
  - Area Classification survey
  - Identify if Survey and Geotechnical studies are required budget and approved
  - Preliminary sizing & spec sheets for major materials/components
- Assumptions
  - List of assumptions used in estimate that affects cost of project
- Sign Off: Asset Management, Engineering, Operations

❒ Class 4 Cost Estimate
- Produced from FortisBC Pipelines Workbook
  - Estimated capital cost and accuracy of estimate
  - Benchmarked costs
  - Preliminary pricing for major materials/components

❒ Preliminary Schedule and Construction Plan
- In-service date, construction start date
  - Project duration
  - Implication of deferral
  - Identify construction constraints including weather, remote locations, resource demands

❒ Risks Assessment (for each option)
- Identify risks associated with the project at this level (eg. Permitting, scheduling, procurement, etc.)

*Once the sign-off is complete, the project can proceed to the Class 3 Classification*

## *Class 3* (Define)

## Required Documentation

❐ Business Case (with preferred option chosen, justification)

❐ Class 3 Front End Engineering Design (FEED) containing:

- Design basis memorandum
  - Route considerations and maps
  - Legal Plan acquired, ROW boundaries determined
  - Potential lands/environmental issues identified
  - Potential major trenchless crossings identified
  - Constraints assessment
  - Approved control methodology and schematic
  - Permitting requirements established
  - Survey data complete
  - Geotechnical data complete
  - Environmental and Archaeological desktop constraints report complete

❐ Class 3 Cost Estimate

- Basis of Estimate
  - Produced from FortisBC Designer Workbook or external consultant
  - Supported with written vendor quotations based on material selection
  - Supported with contractor estimates based on routing options
  - Contingency analysis
- Assumptions
  - List of assumptions used in estimate that affects cost of project
- Clarifications
  - List of clarifications used in estimate that affects cost of project

❐ Approved Schedule and Construction Plan

- In-service date, construction start date
  - Proposed method of installation
  - Long lead items identified
  - Implication of deferral
  - Contingency plan including any bypass installation
- Sign Off:
  - Asset Management
  - PMO
  - Engineering
  - Operations

❐ Risks Assessment for Preferred Option

- Risk identification workshop
- Risk scoring and ranking
- Forms basis of contingency analysis

*Once the sign-off is complete, the project can proceed to the Class 2 Classification*

***Class 2*** (Execute)

Part of Project Management Process and therefore not defined in this document.

***Class 1*** (Operate)

Part of Project Management Process and therefore not defined in this document.

# Gas Pressure Control & Measurement Station Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

## *Pressure Control*

Project class definitions and documentation required.

## *Class 5* (Identify)

## Required Documentation

❒ Class 5 Front End Engineering Design (FEED) containing:

- Project scope
  - Define project scope from known problem or opportunity
  - Justification, needs, and requirements
  - Relevant codes and standards
  - Permitting & Regulatory requirements
- Basis of Design
  - Design parameters
  - System Capacity Planning Documentation
- Options
  - List of options to meet requirements
  - Pros and cons for each option/proposal
- Documentation Checklist
  - Station load and pressure information
  - Station assessment checklist
  - System and general P&ID:
- Schedule:
  - Project duration (1, 2 or 3 years or more)
- Assumptions:
  - List of assumptions used in estimate that affects cost of project
  - List of clarifications used in estimate that affects cost of project
- Sign Off: Asset Management, Engineering, Operations

❒ Class 5 Cost Estimate

- Basis of Estimate
  - Estimate development
  - Benchmarked costs
  - Produced from FortisBC Workbook
- Total project cost estimate based on similar past projects

❒ Risks Assessment (high Level)

- Identify risks associated with the project at this level (eg. Permitting, scheduling, procurement, etc.)

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

***Class 4*** (Evaluate)

## Required Documentation

❒ Updated PERR FEED Request
- Confirming requirements

❒ Class 4 Front End Engineering Design (FEED) containing:
- Project Cost
- Project Description
  - Project scope
  - Key drivers
  - Relevant codes and standards
  - Financial & Operating cost Impact
  - Impacts to other areas of FBC
- Basis of Design
  - Design parameters
  - System Capacity Planning Documentation
  - Station Plan View showing required foot print dimensions
- Options
  - List of options to meet requirements
  - Pros and cons of each option/proposal
  - Risk associated with each option
  - Proposed site location
  - Recognize impact and other areas of FBC
- Related Projects
  - Timing and staging considerations
- Documentation Checklist
  - Station load and pressure information
  - Existing station capacity graph
  - Station assessment checklist
  - Preliminary P&ID
  - Preliminary sizing & spec sheets for major materials/components
- Assumptions
  - List of assumptions used in estimate that affects cost of project
- Sign Off: Asset Management, Engineering, Operations

❒ Class 4 Cost Estimate
- Produced from Pressure Control & Measurement Station estimate templates
  - Estimated capital cost and accuracy of estimate
  - Preliminary pricing for major materials/components

❒ Preliminary Schedule and Construction Plan
- In-service date, construction start date
  - Project duration
  - Implication of deferral
  - Identify construction constraints including weather

❒ Risks Assessment (for each option)
- Identify risks associated with the project at this level (eg. Permitting, scheduling, procurement, etc.)

*Once the sign-off is complete, the project can proceed to the Class 3 Classification*

***Class 3*** (Define)

## Required Documentation

❒ Business Case (with preferred option chosen, justification)

❒ Class 3 Front End Engineering Design (FEED) containing:

- Design basis memorandum
  - Approved station design capacity and specifications
  - Approved P&ID
  - Approved site plan and layout
  - Approved design parameters and equipment sizing
  - Approved control methodology and schematic
  - Permitting requirements established
  - Survey data complete
  - Geotechnical data complete
  - Environmental assessment complete

❒ Approved Schedule and Construction Plan

- In-service date, construction start date
  - Proposed method of installation
  - Long lead items identified
  - Implication of deferral
  - Contingency plan including any bypass installation
- Sign Off:
  - Asset Management
  - PMO
  - Engineering
  - Operations

❒ Class 3 Cost Estimate

- Basis of Estimate
  - Based on approved station layout and P&ID
  - Produced from FortisBC Designer Workbook or external consultant
  - Supported with written vendor quotations based on material selection
  - Supported with contractor estimates based on routing options
  - Contingency analysis
- Assumptions
  - List of assumptions used in estimate that affects cost of project
- Clarifications
  - List of clarifications used in estimate that affects cost of project

❒ Risks Assessment for Preferred Option

- Risk identification workshop
- Risk scoring and ranking
- Forms basis of contingency analysis

*Once the sign-off is complete, the project can proceed to the Class 2 Classification*

### ***Class 2*** (Execute)

Part of Project Management Process and therefore not defined in this document.

### ***Class 1*** (Operate)

Part of Project Management Process and therefore not defined in this document.

# LNG Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

## LNG Projects

Project class definitions and suggested documentation required.

## Class 5 (Identify)

## Required Documentation

❒ Class 5 Front End Engineering Design (FEED) containing:

- Project scope
  - Define project scope from known problem or opportunity
  - Justification, needs, and requirements
  - Relevant codes and standards
  - Permitting & Regulatory requirements
  - Identify if project is a) sustainment b) load growth (e.g. RS46) c) compliance d) safety related
- Basis of Design
  - Design parameters
  - System Capacity Planning Documentation (with regards to gas supply loads)
  - Process analysis review
- Options
  - List of options to meet requirements
  - Pros and cons for each option/proposal
- Documentation Checklist
  - Min / Nom / Max flow rates
  - Operational review with regards to maintainability, operability
  - System and general P&ID:
- Schedule:
  - Project duration (1, 2 or 3 years or more)
- Assumptions:
  - List of assumptions used in estimate that affects cost of project
  - List of clarifications used in estimate that affects cost of project
- Sign Off: Asset Management, Engineering, Operations

❒ Class 5 Cost Estimate

- Basis of Estimate
  - Estimate development
  - Benchmarked costs
  - Produced from FortisBC Workbook
- Total project cost estimate based on similar past projects

❒ Risks Assessment (high Level)

- Identify risks associated with the project at this level (eg. Permitting, scheduling, procurement, etc.)
- Identify operational risks with regards to maintenance schedule, production availability (e.g. number of days of liquefaction or send out impacted, tank level, etc…)

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

*Class 4* (Evaluate)

## Required Documentation

- ❐ Updated PERR FEED Request
  - Confirming requirements

❐ Class 4 Front End Engineering Design (FEED) containing:

- Project Cost
- Project Description
  - Project scope
  - Key drivers
  - Relevant codes and standards
  - Financial & Operating cost Impact
  - Impacts to other areas of FBC
- Basis of Design
  - Design parameters
  - System Capacity Planning Documentation
  - More detailed operational analysis (impact to operability, maintability)
- Options
  - List of options to meet requirements
  - Pros and cons of each option/proposal
  - Risk associated with each option
  - Proposed site location and site plan
  - Recognize impact and other areas of FBC (gas supply, operations, gas control, local customers, etc…)
- Related Projects
  - Timing and staging considerations
- Documentation Checklist
  - Station load and pressure information
  - Existing station capacity graph
  - Station assessment checklist
  - Preliminary P&ID
  - Preliminary sizing & spec sheets for major materials/components
- Assumptions
  - List of assumptions used in estimate that affects cost of project
- Sign Off: Asset Management, Engineering, Operations, Manager Plant Operations

❐ Class 4 Cost Estimate

- Produced from Pressure Control & Measurement Station estimate templates
  - Estimated capital cost and accuracy of estimate
  - Preliminary pricing for major materials/components
  - Procurement time for major components

❐ Preliminary Schedule and Construction Plan

- In-service date, construction start date
  - Project duration
  - Implication of deferral
  - Identify construction constraints including weather

❐ Risks Assessment (for each option)

- Identify risks associated with the project at this level (eg. Permitting, scheduling, procurement, etc.)
- Conduct preliminary HAZOPS review of operational changes to identify any key safety issues

*Once the sign-off is complete, the project can proceed to the Class 3 Classification*

## ***Class 3*** (Define)

## Required Documentation

❒ Business Case (with preferred option chosen, justification)

❒ Class 3 Front End Engineering Design (FEED) containing:

- Design basis memorandum
  - Approved station design capacity and specifications
  - Approved P&ID
  - Approved site plan and layout
  - Approved design parameters and equipment sizing
  - Approved control methodology and schematic
  - Permitting requirements established
  - Survey data complete
  - Geotechnical data complete
  - Environmental assessment complete

❒ Approved Schedule and Construction Plan

- In-service date, construction start date
  - Proposed method of installation
  - Long lead items identified
  - Implication of deferral
  - Contingency plan including any bypass installation and/or back up supplies from other LNG facilities identified
- Sign Off:
  - Asset Management
  - PMO
  - Engineering
  - Operations
  - Manager, Plant Operations

❒ Class 3 Cost Estimate

- Basis of Estimate
  - Based on approved station layout and P&ID
  - Produced from FortisBC Designer Workbook or external consultant
  - Supported with written vendor quotations based on material selection
  - Supported with contractor estimates based on routing options
  - Contingency analysis
- Assumptions
  - List of assumptions used in estimate that affects cost of project
- Clarifications
  - List of clarifications used in estimate that affects cost of project

❒ Risks Assessment for Preferred Option

- Risk identification workshop
- Risk scoring and ranking
- Forms basis of contingency analysis
- HAZOP completed and reviewed
- Maintenance approach, method and documentation complete and approved by Asset Management Maintenance group

*Once the sign-off is complete, the project can proceed to the Class 2 Classification*

### ***Class 2*** (Execute)

Part of Project Management Process and therefore not defined in this document.

### ***Class 1*** (Operate)

Part of Project Management Process and therefore not defined in this document.

# Telecommunications Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

## Telecommunications

Project class definitions and documentation required.

## *Class 5* (Identify)

## Required Documentation

❒Capital Planning Initiation Document (CPID) containing:

- Planning Project Definition:
  - From problem /opportunity project definition developed (progress into scope document)
- Schedule:
  - Duration 1, 2 or 3 or more Years
  - Year to be completed
- Goals
- Project Components
- Justification Needs/Requirements
- Operational Problems: From SCC Outage Reports

Options

- Technology Choices
  - List of options to be looked at with high level costs
- System Comm Block Diagram:
  - Major Equipment only
- Assumptions
  - List of assumptions used in estimate that effects cost of project
- Planning System Documentation
  - High Level Cost
  - Planning Study
- Sign Off: PMO, Planning, Engineering, Operations

❒Class 5 Estimate

- Produced from Planning Line Estimate
  - Corporate financials are calculated and added to base estimate

❒Risks Assessment (High Level)

- Identify risks associated with the project at this level

*Once the sign-off is complete, the project can proceed to the Class 4 Classification*

***Class 4*** (Evaluate)

## Required Documentation

❒ Business case (with all options) containing:
- Project Cost
- Description of the Project
- Key Drivers
- In-Service Date, Construction Start Date
- Implications of Deferral
- Financial Impact
  - Estimated Capital Cost and Accuracy of Estimate
  - Operating Cost Impact
  - Recognize impact and other areas of FBC
  - Estimated ongoing provider lease costs (Telecom)
- Performance Requirements (telecom)
  - Bandwidth needed
  - Latency
  - Availability
  - Expected Applications
- Recommended Technology (Telecom)
- Options
  - Pros and Cons as well as the impacts on DSM
- Related Projects
  - Timing and staging considerations
- Risks/Other Considerations (high identification)
- Documentation Check List
  - Comm Block Diagram (telecom)
  - Coverage Studies (if applicable)
  - Preliminary Path Study (If needed)
  - Coordination with other utilities if required
- Sign Off: PMO, Planning, Engineering, Operations

❒ Class 4 Estimate
- Corporate financials are calculated and added to base estimate
- Major Material List

❒ Preliminary Schedule and Construction Plan
- Engineering, Construction and Commissioning schedules are determined
- Starting quarter and ending quarter identified
- Identify construction constrains including weather, remote location switching request

❒ Risks Assessment (for each option)
- Identify risks associated with the project at this level

*Once the sign-off is complete, the project can proceed to the Class 3 Classification*

***Class 3*** (Define)

## Required Documentation

❒ Business Case (with preferred option chosen, justification)

❒ Class 3 Estimate
- Produced from FortisBC Designer Workbook
- Corporate financials are calculated and added to base estimate
- Approved Comm Block Diagram (Telecom)
- Material list complete
- Finalized Structure Locations
- Route Profile

❒Approved Construction Plan and Schedule
- Contingency plan including switching plan

❒ Risks Assessment for preferred option
- Identify risks associated with the project at this level

❒ Preliminary Budget Set
- Sign Off: PMO, Planning, Engineering, Operations

The schedule and estimate should be located in the specific folder on SharePoint Site

Once sign-offs are complete, the project can proceed to the Class 2 classification.

***Class 2*** (Execute)

Part of Project Management Process and therefore not defined in this document

***Class 1*** (Operate)

Part of Project Management Process and therefore not defined in this document