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June 18, 2015

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Lower Mainland Intermediate Pressure (IP) System Upgrade (LMIPSU) Projects (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 2

On December 19, 2014, FEI filed the Application referenced above. In accordance with Exhibit A-7 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 2.

In the course of responding to IR No. 2, FEI has concluded that its response to BCUC IR 1.24.1, although accurate, did not provide a complete explanation as to why an adjustment to its 2013 Base O&M is not necessary for the LMIPSU CPCN. FEI refers the Commission to its response to CEC IR 2.19.1 which more thoroughly analyzes the amount of costs related to the LMIPSU CPCN that were embedded in the 2013 Base O&M.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

A. PROJECT NEED AND JUSTIFICATION - COQUITLAM GATE

1.0 Reference: A SAFETY AND REGULATORY CONCERN

Exhibit B-1, Sections 3.1.2.2, 3.2.2, pp. 32–34

On-going integrity and leak management vs. rehabilitate vs. replace

On page 19 of the Application FEI states:

> …With consideration to the cause of leaks, extent of leaks, expected increase in leak frequency, and lack of effective prevention methods, FEI has determined that pipe replacement is the most appropriate mitigation method.
>
> Replacement meets the requirements of Canadian Standards association (CSA) Z662 Section 12.10.2.3 (d) which states "Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they should not be retained in service, they shall be replaced, reconditioned, or abandoned". Replacement also meets the requirements of the BC Oil and Gas Activities Act Section 37 (3) which states "A person who is aware that spillage is occurring or likely to occur must make reasonable efforts to prevent or assist in containing or preventing the spillage."

On page 32 of the Application FEI explains:

> The [continuing ongoing integrity and leak management] alternative is not an accepted long-term operating practice for management of potential safety risks to the public, plant, property and FEI personnel.

1.1 Please confirm and provide evidence, otherwise explain, that the Oil and Gas Commission (OGC) would not accept continuing ongoing integrity and leak management as a longer-term (i.e. 5-10 years) means to prevent or assist in containing or preventing the spillage.

<u>Response:</u>

The BC OGC response letter is provided in Attachment 1.1, which advises FEI as follows:

> "The OGC would not accept leak survey, leak detection and repair as a means to prevent spillage. Increased leak survey frequency is expected to reduce the consequence associated with a spillage but not prevent future leaks.
>
> Section 37(3) of the *Oil and Gas Activities Act* requires that: Permit holders aware that spillage is likely to occur must make reasonable efforts to prevent or assist in containing or preventing spillage.

> To meet its regulatory obligations, the permit holder must demonstrate that the increased leak survey frequency (1 week) is sufficient to ensure that the pipeline can continue to remain in service and not present undue risk to the public or the environment until the replacement line is commissioned. From the OGC's perspective, it is not desirable to delay replacement until a pipeline is inoperable. The process of replacement takes time."

This aligns with FEI's Engineering Assessment which did not identify continued leak management, in the absence of an active replacement strategy, as an acceptable option other than as an interim measure.

1.1.1 If the OGC would accept continuing ongoing integrity and leak management as a longer-term (i.e. 5-10 years) means to prevent or assist in containing or preventing the spillage, please provide the pro forma, the PV Incremental Cost of Service – 60 Yr and the adjusted PV Remaining Operational Risk 60 Yr, assuming the existing pipeline is managed and then replaced with the preferred alternative in 2025.

Response:

Please refer to the response to BCUC IR 2.1.1. The OGC has advised FEI that it would not accept continuing ongoing integrity and leak management as a longer-term means to prevent spillage.

On pages 33 and 34 of the Application FEI explains:

> Rehabilitation of the existing pipeline would involve proactively excavating each girth weld location along the pipeline, inspecting for corrosion and repairing where necessary.[1]

[1] Exhibit B-1, p. 33.

This alternative does not fully mitigate potential future pipeline corrosion leaks because only the pipeline at each weld location would have been exposed for inspection, evaluation and repair.[2]

1.2 Please explain what future pipeline corrosion leaks FEI would expect, if any, in the existing pipeline, if each weld location were repaired. Has FEI identified any corrosion or leaks at any locations other than the girth weld locations on this line?

Response:

Within Table 3-1 (page 41) of FEI's Application (Exhibit B-1), Alternative 2 "Rehabilitate Existing NPS 20" is identified as partially meeting the objective of reducing pipeline risk. The "partial" qualification is due to there being no technical methods to identify girth weld locations from above ground. Hence, unless the entire length of the pipeline was excavated, it would be possible that some welds could be missed for inspection.

It is considered possible that coating repairs on the pipe body during the original construction may have behaved the same or similarly to field applied joint coatings. Without inspecting the entire pipeline, some future leak uncertainty associated with the pipe body would remain. To date, FEI does not have record of any corrosion leaks on the existing NPS 20 Coquitlam Gate IP pipeline at locations other than girth welds.

As stated in Section 3.2.2.2 (pages 33 to 34) of the Application (Exhibit B-1), a rehabilitation option presents numerous disadvantages including no enhancement to operational flexibility or system resiliency, as well as significant construction constraints. The response to CEC IR 1.27.2 contains further discussion on the construction constraints.

1.3 Please confirm, otherwise explain, that the OGC would consider FEI's rehabilitation an acceptable means to prevent or assist in containing or preventing the spillage.

Response:

Please refer to Attachment 1.1 provided in response to BCUC IR 2.1.1. The BC OGC has advised FEI as follows:

[2] Ibid. p. 34.

> "Assuming the rehabilitation work is to dig up and inspect EVERY weld, this option would be considered by the OGC. FortisBC Energy Inc. (FEI) would also have to demonstrate that the rest of the pipeline is fit for service and continue the increased frequency leak survey on uninspected sections of the pipeline, until all the welds have been inspected and repaired where necessary. This approach is based on no increased leak frequency or size of leak being detected."

1.4 Please confirm, otherwise explain, that the OGC does not consider or review the cost of what FEI proposes as mitigation in response to the OGC order.

Response:

Please refer to Attachment 1.1 provided in response to BCUC IR 2.1.1. The BC OGC has advised FEI as follows:

> "The OGC issued the order to FEI in response to increased incidents being reported on the pipeline. In making the order, the OGC considered the protection of public safety and the environment. It is not part of the OGC's mandate to review the costs of recommendations proposed by the Engineering Assessment. The OGC reviews the technical aspects of the recommendation alone."

1.5 Please confirm, otherwise explain, that the OGC considers and reviews what FEI has proposed as mitigation in response to the OGC order and does not consider or review any other potentially suitable alternative mitigation.

Response:

Please refer to Attachment 1.1 provided in response to BCUC IR 2.1.1. The BC OGC has advised FEI as follows:

> "The Engineering Assessment submitted as per the OGC order fulfills that requirement of the order. The Engineering Assessment recommended replacement of the pipeline. Any application for an approval to replace this pipeline would be reviewed when it is submitted to the OGC; the OGC reviews what is submitted in the application to ensure that the design put forward meets the relevant Acts, Regulations and Standards."

FEI recognizes its responsibility as the pipeline operator to identify and assess mitigation options with consideration of many factors, including regulation and the interests of customers.

2.0 Reference: PROJECT JUSTIFICATION

Exhibit B-4, BCUC 1.2.3

Tethered in-line inspection

In response to BCUC IR 1.2.3 FEI states: "In-line inspection has not been deemed a viable option due to low operating pressures and the expected presence of inside diameter restrictions."

2.1 Please explain tethered in-line inspection.

Response:

Tethered in-line inspection (ILI) is a process whereby a pipeline must be removed from service to enable the inspection. It can be a possible alternative in situations where there is insufficient natural gas flow to propel a traditional ILI tool through the pipeline.

The following is a description of FEI's understanding of a common approach to tethered ILI (as it would apply to a pipeline similar to the Coquitlam Gate IP pipeline):

- Appropriate locations for the start and end of each ILI segment are determined. The expected presence of inside diameter restrictions, numerous pipe bends, and stations (supply points) in the Coquitlam Gate IP pipeline or similar pipelines would require that the pipeline be sectioned into many short segments;
- Temporary gas supplies or bypasses are installed (as required) and the valve section where the inspection segment(s) is located is isolated and purged of gas;
- Excavations are conducted at each end of the inspection segment(s) to expose the pipeline and conduct ILI operations;
- Spools of pipe are removed at segment ends to allow insertion and removal of cleaning and ILI tools;
- Temporary launch and receive facilities are installed (welded onto the pipe) to allow cleaning of the isolated pipe segment;
- The pipeline is cleaned by running tools through the isolated segment propelled using nitrogen or compressed air;
- If the cleaning tools identify any obstructions which will inhibit the passage of the smart tool the obstructions are located, excavated and removed or the pipeline further segmented;

- A gauge or caliper tool is run to ensure that there are no restrictions which would inhibit passage of or cause damage to the smart tool;
- The temporary launch and receive cleaning facilities are removed and a temporary specialized launcher is installed on the pipeline to allow launch of the tethered metal loss inspection smart tool;
- A smart tool with an attached cable or tether is inserted into the pipeline, and pushed along a designated length using nitrogen;
- The temporary launch assembly is removed and a temporary winch assembly is installed to pull the tool back to the launch point;
- Using the cable or tether, the smart tool is winched back to the insertion point at an appropriate speed to enable data collection;
- The data is analyzed to ensure that full data has been collected. If debris impacting the collection of data is still present, additional cleaning runs are preformed and the smart tool is rerun;
- The pipeline spools are restored, recoated and the excavations are backfilled; and
- The isolated valve segment is purged of air, re-gasified and brought back into service.

2.2 Please confirm that FEI considered tethered in-line inspection to identify problem areas in the Coquitlam line. If not, why not?

Response:

Confirmed. FEI did consider in-line inspection, including tethered in-line inspection, to manage the corrosion risk on the Coquitlam Gate IP pipeline. FEI does not consider tethered in-line inspection as a project alternative due to the following issues associated with that methodology:

- Expected presence of inside diameter restrictions that would prevent tool passage and require significant sectioning of the pipeline into short segments for inspection;
- Uncertainty in the number of bends which would restrict the length of pipeline that could be inspected with a single tethered tool run;

- Supply risk associated with taking multiple sections of pipeline out of service for numerous and/or extended periods of time to clean and inspect the pipeline; and
- In-line inspection tools (both tethered and traditional ILI) do not have the capability to detect and accurately size all pinhole corrosion features. As such, differentiation would not be possible between weld areas with relatively inconsequential general corrosion (i.e. not likely to result in an immediate leak) and those with near-through-wall pinhole features.

FEI also notes that a hypothetical tethered in-line inspection option (along with any necessary repairs) would not address maintenance flexibility and system resiliency concerns with the existing NPS 20 Coquitlam Gate IP pipeline.

2.3 Please explain how FEI would perform tethered in-line inspection on the Coquitlam Gate IP pipeline to identify and locate areas of concern.

Response:

Due to the issues associated with tethered ILI described in the response to BCUC IR 2.2.2, FEI does not consider tethered ILI to be viable for the Coquitlam Gate IP pipeline or as a project alternative.

2.4 Please compare the costs and benefits of using tethered in-line inspection to detect problem areas to FEI's rehabilitation method.

Response:

Please refer to the response to BCUC IR 2.2.3.

2.5 Please provide the pro forma, the PV Incremental Cost of Service – 60 Yr and the adjusted PV Remaining Operational Risk 60 Yr, assuming the existing pipeline is inspected using tethered in-line inspection, and repaired, and then replaced with the preferred alternative in 2025.

Response:

Please refer to the response to BCUC IR 2.2.3.

As tethered ILI is not a feasible project alternative, a 60-year cost of service has not been prepared.

2.6 Does FEI foresee any future in-line inspection issues with the new proposed Coquitlam pipeline design? If so, please discuss how FEI plan to mitigate these issues.

Response:

Although FEI does not have direct experience in running in-line inspection tools in intermediate pressure pipelines, discussions with vendors indicate that the proposed design and operating parameters would allow for successful inspection of the proposed pipeline.

B. PROJECT ALTERNATIVES – COQUITLAM GATE

3.0 Reference: OPERATIONAL FLEXIBILITY AND RESILIENCY

Exhibit B-4, BCUC 1.3.3

Outage windows and days of resiliency of alternatives

In response to BCUC IR 1.3.3 FEI provides a table which includes the estimated historical outage windows on the Metro IP.

3.1 Similar to the response to BCUC IR 1.3.3., please fill in the table below with the forecast estimated outages windows on the Metro IP for the 20-year planning horizon, and in 30, 40, and 60 years, for Alternatives 4, 5 and 6.

	Fraser Gate Outage Window If Alternative 4 (Replace with NPS 24 at 2070kPa)	Fraser Gate Outage Window If Alternative 5 (Replace with NPS 36 at 1200kPa)	Fraser Gate Outage Window If Alternative 6 (Replace with NPS 30 at 2070kPa)
2015			
2016			
2017			
…			
2034			
2044			
2054			
2074			

<u>Response:</u>

The following table identifies the estimated outage windows for Alternatives 4, 5 and 6 from the in-service date until 2074 based on the current peak hour forecast.

Fraser Gate Outage Window

Year	Alternative 4 (NPS 24 @ 2070 kPa)	Alternative 5 (NPS 36 @ 1200 kPa)	Alternative 6 (NPS 30 @ 2070 kPa)
2019	Late February to Late November	Late January to Mid December	Year Round
2020	Late February to Late November	Late January to Mid December	Year Round
2021	Late February to Late November	Late January to Mid December	Year Round
2022	Early March to Late November	Late January to Mid December	Year Round
2023	Early March to Late November	Late January to Mid December	Year Round
2024	Early March to Late November	Late January to Mid December	Year Round
2025	Early March to Late November	Late January to Mid December	Year Round
2026	Early March to Late November	Late January to Mid December	Year Round
2027	Early March to Mid November	Late January to Mid December	Year Round
2028	Early March to Mid November	Late January to Mid December	Year Round
2029	Early March to Mid November	Late January to Mid December	Year Round
2030	Early March to Mid November	Late January to Mid December	Year Round
2031	Early March to Mid November	Late January to Mid December	Year Round
2032	Early March to Mid November	Late January to Mid December	Year Round
2033	Early March to Mid November	Early February to Early December	Year Round
2034	Mid March to Mid November	Early February to Early December	Year Round
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2044	Mid March to Mid November	Mid February to Early December	Year Round
---	-------	-------	-------
2054	Mid March to Early November	Late February to Late November	Year Round
---	-------	-------	-------
2074	Mid March to Early November	Early March to Mid November	Year Round

3.2 Please quantify (in $) and explain the incremental benefit of the additional operational flexibility offered by a 30" pipeline vs. a 24" pipeline.

Response:

The proposed NPS 30 (2070 kPa) pipeline provides full resiliency to the end of the planning period and would allow work that may require isolation of supply at either the Coquitlam or the Fraser Gate station to be accommodated at any time of year. Work performed on the Metro IP system would not incur any additional costs for bypass piping around the work area. Emergency situations requiring isolation would not incur significant customer outages and associated costs.

The NPS 24 (2070 kPa) pipeline does not provide full resiliency. At the end of the 20 year planning period there would be approximately 12 days in a normal year that would not allow work requiring an isolation of the supply at either gate station to proceed if the NPS 24 (2070kPa) was installed. This would restrict work of such isolation to the period between Mid-March to Mid-November where it is most improbable that one of the 12 colder days of the year would occur. This would provide an operational window sufficient for work that is planned in advance to be completed within this window. Work in colder months outside of this operational window (i.e. between Mid-November and Mid-March) would require that the gate stations remain in service and that bypass piping be installed around the isolated section to provide necessary support to the downstream system should the expected 12 colder days of the winter occur during the course of work.

The cost to FEI per occurrence would be the cost of installing and then removing the bypass piping. Costs would vary depending on the location of the work (impacting bypass pipe size required) and the total length and routing needed to span the work area. Please also refer to the response to BCOAPO IR 1.3.7 for an estimate of the costs of typical bypasses that may be needed for such work. An estimate of total cost that may be incurred over a given number of years related to the cost of additional work needed due to this lack of full resiliency cannot be fully determined because the total number of occurrences is unpredictable.

Work that would have to be performed outside of the identified operational window would be unplanned and of very urgent nature and would drive up either bypass installation costs or costs associated with possible widespread customer outages.

The financial incremental benefit of the NPS 30 (2070 kPa) pipeline over the NPS 24 (2070 kPa) pipeline would be the avoidance of any costs associated with bypass installation and costs associated with customer outages.

3.3 Please fill in the table below to show the progression of the approximate number of days the Metro IP is not resilient in the 20-year planning horizon, and in 30, 40, and 60 years, if either Alternatives 4, 5 or 6 are commissioned:

	Alternative 4 Replace with NPS 24 at 2070kPa	Alternative 5 Replace with NPS 36 at 1200kPa	Alternative 6 Replace with NPS 30 at 2070kPa
2015			
2016			

2017			
2018			
2019			
…			
2034	E.g. 12 days[3]		
2044			
2054			
2074			

<u>Response:</u>

As determined in accordance with the response to BCUC IR 1.9.1.1, the table below identifies the number of days in a normal year that the various alternatives of the Metro IP system would not be fully resilient. The table spans the period from the in-service date until 2074.

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[3] Exhibit B-4, BCUC 9.1.1.

Days in a Normal Year that Full Resiliency is Not Achieved

Year	Alternative 4 (NPS 24 @ 2070 kPa)	Alternative 5 (NPS 36 @ 1200 kPa)	Alternative 6 (NPS 30 @ 2070 kPa)
2019	7 Days	3 Days	0 Days
2020	8 Days	3 Days	0 Days
2021	8 Days	3 Days	0 Days
2022	8 Days	3 Days	0 Days
2023	9 Days	3 Days	0 Days
2024	9 Days	3 Days	0 Days
2025	9 Days	3 Days	0 Days
2026	9 Days	3 Days	0 Days
2027	10 Days	4 Days	0 Days
2028	10 Days	4 Days	0 Days
2029	11 Days	4 Days	0 Days
2030	11 Days	4 Days	0 Days
2031	11 Days	4 Days	0 Days
2032	11 Days	4 Days	0 Days
2033	11 Days	4 Days	0 Days
2034	12 Days[1]	5 Days	0 Days
---	-------	-------	-------
2044	14 Days	6 Days	0 Days
---	-------	-------	-------
2054	17 Days	7 Days	0 Days
---	-------	-------	-------
2074	24 Days	11 Days	0 Days

[1] See response to BCUC IR 1.9.1.1

4.0 Reference: LOAD FORECAST

Creative Energy - NES NEFC CPCN proceeding, Exhibit B-1, pp. 3–4; Schedule 9

Exhibit B-2, p. 2

Load variability and design capacity

An Application from Creative Energy and supported by the City of Vancouver suggests that Creative Energy is expected to convert from natural gas to a low carbon energy source in 2020.[4, 5]

The City of Vancouver explains:

> For the Downtown area, the key Neighbourhood Energy Strategy actions are to:
>
> - convert the Central Heat Distribution Ltd. system (also referred to in this report as the "Downtown steam system") from natural gas to a low carbon energy source. [6]

4.1 Please provide Creative Energy's peak hour load and compare this to the Metro IP peak hour load.

Response:

The Central Heat Distribution Ltd. (now Creative Energy)'s "Downtown steam system" has a firm contract for natural gas with FEI for 2000 GJ/day (2612 standard cubic meters per hour). A significant portion of the load delivered under off peak conditions is interruptible and would be curtailed under design day peak hour conditions.

The contract firm load represents approximately 0.43% of the peak hour load estimated to flow into the Metro IP system on a design degree day.

4.1.1 Please discuss the impacts of Creative Energy converting from gas on the design peak demand of the Metro IP and the corresponding design capacity for the proposed new Coquitlam IP pipeline.

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4 Creative Energy NES NEFC CPCN, Exhibit B-1, pp. 3–4.
5 Creative Energy NES NEFC CPCN, Exhibit B-1, Schedule 9.
6 Creative Energy NES NEFC CPCN, Exhibit B-2, p. 2.

Response:

The conversion of Creative Energy from natural gas to an alternative source of energy, if it were to occur, would have no significant impact on the capacity of the proposed new Coquitlam Gate IP pipeline required for design day conditions.

Under design day conditions, the impact would be a reduction of less than one half of one percent in peak hour demand. The peak hour demand reduction impact is not significant enough to allow the NPS 24 (2070 kPa) alternative to provide full resiliency.

4.2 Please resubmit the tables requested in questions 3.1 and 3.3 assuming a 10% lower peak day demand forecast and a 10% higher peak day demand forecast.

Response:

The following tables reproduce the tables provided in the responses to BCUC IRs 2.3.1 and 2.3.3 for a 10% lower peak day forecast followed by tables for a 10% higher peak day forecast.

Fraser Gate Outage Window

10 % Lower Peak Day Forecast

Year	Alternative 4 (NPS 24 @ 2,070 kPa)	Alternative 5 (NPS 36 @ 1,200 kPa)	Alternative 6 (NPS 30 @ 2070 kPa)
2019	Late February to late November	Late January to Mid December	Year Round
2020	Late February to late November	Late January to Mid December	Year Round
2021	Late February to late November	Late January to Mid December	Year Round
2022	Late February to late November	Late January to Mid December	Year Round
2023	Early March to late November	Late January to Mid December	Year Round
2024	Early March to late November	Late January to Mid December	Year Round
2025	Early March to late November	Late January to Mid December	Year Round
2026	Early March to late November	Late January to Mid December	Year Round
2027	Early March to Mid November	Late January to Mid December	Year Round
2028	Early March to Mid November	Late January to Mid December	Year Round
2029	Early March to Mid November	Late January to Mid December	Year Round
2030	Early March to Mid November	Late January to Mid December	Year Round
2031	Early March to Mid November	Late January to Mid December	Year Round
2032	Early March to Mid November	Late January to Mid December	Year Round
2033	Early March to Mid November	Late January to Mid December	Year Round
2034	Early March to Mid November	Early February to Early December	Year Round
---	-------	-------	-------
2044	Mid March to Mid November	Early February to Early December	Year Round
---	-------	-------	-------
2054	Mid March to Early November	Mid February to Late November	Year Round
---	-------	-------	-------
2074	Mid March to Early November	Early March to Mid November	Year Round

1

Days in a Normal Year that Full Resiliency is Not Achieved

10 % Lower Peak Day Forecast

Year	Alternative 4 (NPS 24 @ 2,070 kPa)	Alternative 5 (NPS 36 @ 1,200 kPa)	Alternative 6 (NPS 30 @ 2070 kPa)
2019	7 Days	3 Days	0 Days
2020	7 Days	3 Days	0 Days
2021	8 Days	3 Days	0 Days
2022	8 Days	3 Days	0 Days
2023	8 Days	3 Days	0 Days
2024	8 Days	3 Days	0 Days
2025	9 Days	3 Days	0 Days
2026	9 Days	3 Days	0 Days
2027	9 Days	3 Days	0 Days
2028	9 Days	3 Days	0 Days
2029	10 Days	4 Days	0 Days
2030	11 Days	4 Days	0 Days
2031	11 Days	4 Days	0 Days
2032	11 Days	4 Days	0 Days
2033	11 Days	4 Days	0 Days
2034	11 Days	4 Days	0 Days
---	-------	-------	-------
2044	13 Days	5 Days	0 Days
---	-------	-------	-------
2054	16 Days	6 Days	0 Days
---	-------	-------	-------
2074	22 Days	10 Days	0 Days

Fraser Gate Outage Window

10 % Higher Peak Day Forecast

Year	Alternative 4 (NPS 24 @ 2,070 kPa)	Alternative 5 (NPS 36 @ 1,200 kPa)	Alternative 6 (NPS 30 @ 2070 kPa)
2019	Late February to Late November	Late January to Mid December	Year Round
2020	Late February to Late November	Late January to Mid December	Year Round
2021	Early March to Late November	Late January to Mid December	Year Round
2022	Early March to Late November	Late January to Mid December	Year Round
2023	Early March to Late November	Late January to Mid December	Year Round
2024	Early March to Late November	Late January to Mid December	Year Round
2025	Early March to Late November	Late January to Mid December	Year Round
2026	Early March to Mid November	Late January to Mid December	Year Round
2027	Early March to Mid November	Late January to Mid December	Year Round
2028	Early March to Mid November	Late January to Mid December	Year Round
2029	Early March to Mid November	Late January to Mid December	Year Round
2030	Early March to Mid November	Late January to Mid December	Year Round
2031	Early March to Mid November	Early February to Mid December	Year Round
2032	Early March to Mid November	Early February to Mid December	Year Round
2033	Early March to Mid November	Early February to Mid December	Year Round
2034	Early March to Mid November	Early February to Early December	Year Round
---	-------	-------	-------
2044	Mid March to Mid November	Mid February to Late November	Year Round
---	-------	-------	-------
2054	Mid March to Early November	Late February to Late November	Year Round
---	-------	-------	-------
2074	Mid March to Early November	Early March to Mid November	Year Round

Days in a Normal Year that Full Resiliency is Not Achieved

10 % Higher Peak Day Forecast

Year	Alternative 4 (NPS 24 @ 2,070 kPa)	Alternative 5 (NPS 36 @ 1,200 kPa)	Alternative 6 (NPS 30 @ 2070 kPa)
2019	8 Days	3 Days	0 Days
2020	8 Days	3 Days	0 Days
2021	8 Days	3 Days	0 Days
2022	9 Days	3 Days	0 Days
2023	9 Days	3 Days	0 Days
2024	9 Days	3 Days	0 Days
2025	9 Days	3 Days	0 Days
2026	10 Days	4 Days	0 Days
2027	10 Days	4 Days	0 Days
2028	11 Days	4 Days	0 Days
2029	11 Days	4 Days	0 Days
2030	11 Days	4 Days	0 Days
2031	11 Days	4 Days	0 Days
2032	11 Days	5 Days	0 Days
2033	11 Days	5 Days	0 Days
2034	12 Days	5 Days	0 Days
---	-------	-------	-------
2044	14 Days	6 Days	0 Days
---	-------	-------	-------
2054	19 Days	7 Days	0 Days
---	-------	-------	-------
2074	26 Days	12 Days	0 Days

4.3 Please confirm, otherwise explain, that alternative 4 (24” pipeline at 2070kPa) would offer FEI sufficient operational flexibility and resiliency in the event of a 10% lower peak day demand forecast over the 20-year forecast period.

<u>Response:</u>

Not confirmed. Please refer to the tables in the response to BCUC IR 2.4.2. The tables demonstrate that a NPS 24 (at 2070 kPa) solution would still encounter 11 days in a Normal Year in 2034 when an outage could not be supported.

4.4 Please confirm, otherwise explain, that the preferred alternative (30" pipeline at 2070kPa) would offer FEI sufficient operational flexibility and resiliency in the event of the addition of 10% higher peak day demand forecast over the same period.

Response:

Confirmed. Please refer to the tables for the 10% higher peak hour load forecast provided in the response to BCUC IR 2.4.2.

5.0 Reference: COQUITLAM GATE IP

Exhibit B-4, BCUC 1.3.2, 1.6.1, 1.6.2

Coquitlam gate IP pipeline capacity

In response to BCUC IR 1.3.2 FEI provides a Pipeline Capacity Comparison Table. In response to BCUC IRs 1.6.1 and 1.6.2 FEI states that the 2014-15 and 2034-35 Design Peak Hour Loads for the Metro IP System are 611,000 and 645,900 cubic metres per hour, respectively.

5.1 In order to illustrate the effect of the proposed projects on the capacity of the Metro IP System in the future, please provide a copy of the Pipeline Capacity Comparison Table for the situation in 2034-35.

Response:

The load for 2034-35 referred to in the preamble to this IR was transposed incorrectly; the total load provided in BCUC IR 1.6.2 was 654,900 standard cubic metres per hour.

The bottom two rows of the Pipeline Capacity Comparison Table provided in BCUC IR 1.3.2 show the pipeline flow (estimated capacity) that is possible, given the same pressure constraints, at any time in the future after the proposed Project is installed. The numbers in the table are representative of the future capacity of the proposed Metro IP system.

FEI developed the Pipeline Capacity Comparison Table provided in the response to BCUC IR 1.3.2 to provide a comparison of the various individual components of its integrated Metro IP gas delivery system. The table reflects the challenges of trying to isolate, and represent on a comparative basis, the capacity of single components of a very interconnected and complex distribution system. It should also be noted that the existing system configuration and the proposed system configuration are not identical. The proposed system will result in the NPS 12 1200 kPa system flowing east from Coquitlam Gate being separated from the NPS 30 2070 kPa pipeline flowing west from Coquitlam Gate. Moreover, the NPS 12 will be fed by an independent TP/IP (1200 kPa) station on the Coquitlam site. In the current system, the NPS 12 1200 kPa system east of Coquitlam gate is not separate or able to be independently isolated from the existing NPS 20 1200 kPa pipeline. The following describes how the table can be applied to illustrate the potential demand requirements compared to the capacity of each pipeline in 2034-35.

In 2034, the estimated demand on the proposed NPS 30 (2070 kPa) system flowing west from Coquitlam, is approximately 612,300 standard cubic metres per hour. The balance of the 2034-35 demand of 654,900 standard cubic metres per hour noted above (42,600 standard cubic metres per hour flowing east from the Coquitlam Gate location) is supported by a separate 1200 kPa supply from Coquitlam Gate described above feeding existing NPS 12 (1200 kPa) pipelines not being replaced or upgraded as part of the Project. Reproduced below, are the relevant rows of the Pipeline Capacity Comparison Table previously provided in the response to BCUC IR 1.3.2 with the expected pipeline flow in 2034-35 appended in the last column. Comparing the values in the last two columns illustrates the effect the proposed Metro IP System Project has in meeting the capacity requirements in 2034-35.

Pipeline Capacity Comparison Table

IP System	IP Pipeline	Fraser Gate Supply	Coquitlam Gate Supply	% of 2014 Peak Hour Demand	Pipeline Flow Capacity* (m^3/hr)	Pipeline Flow Required in 2034-35 (m^3/hr)
Proposed Metro IP System	Fraser Gate IP Pipeline	on	off	107.50%	620,700	612,300
	New Coquitlam Gate IP Pipeline	off	on	125.00%	726,600	612,300

* as Metro IP system reaches min design pressure constraint

5.1.1 Please reconcile the information used to prepare the Pipeline Capacity Comparison Table with the figure of 611,000 cubic metres per hour in BCUC IR 1.6.1.

<u>Response:</u>

The load for 2034-35 referred to in the preamble to this IR was transposed incorrectly, the total load provided in BCUC IR 1.6.2 was 654,900 standard cubic meters per hour.

As discussed in the response to BCUC IR 2.5.1, the Metro IP System is part of a very interconnected and complex distribution system. Not explicitly represented in the table in the response to BCUC IR 1.3.2 is the interconnecting distribution pressure system and a third gate station (Pattullo Gate), which supports a smaller portion of Metro area customers in New Westminster, Burnaby and Coquitlam. Depending on how the loading is distributed along the system, as the total system load increases or decreases, some redistribution of flow through the three gate stations will occur.

To illustrate how the line items in the Pipeline Capacity Comparison Table provided in response to BCUC IR 1.3.2 can be reconciled to the stated system load, the following example addresses the first row of the table.

The design peak hour load of 611,300 standard cubic metres per hour (rounded to the nearest 1000 in the response to BCUC IR 1.6.1) is the estimated design day peak hour demand flowing into the Metro IP system for 2014-15 through Fraser Gate and Coquitlam Gate in a balanced hydraulic model of the system. The larger system including Pattullo Gate flows another 95,400 standard cubic metres per hour for a total of approximately 706,700 standard cubic metres per hour. This peak hour demand was distributed along the system to reflect the current peak hour loading of all connected district stations in 2014. The table shows that the existing Metro system (the Metro IP system and the interconnecting Pattullo distribution system) without support of Coquitlam Gate can only support 63.5% of the 2014-15 peak hour demand. Applying the factor directly, the assumption using simple math would be that the flow at Fraser Gate (the capacity of the Fraser Gate IP pipeline) should be 63.5% of 611,300 or 388,200 standard cubic metres per hour, however the table in the response to BCUC IR 1.3.2 shows that 383,700 standard cubic metres per hour is flowing though the Fraser Gate IP Pipeline when the system starts to reach delivery pressure constraints. The reconciliation is provided by Pattullo Gate which responds by increasing its support of the system under the imposed loading. When steady state equilibrium of the system is computed, Pattullo Gate is supporting proportionally more of the system demand and contributes 65,100 standard cubic metres per hour, providing an additional 4500 standard cubic metres per hour that the Fraser Gate IP is not providing.

6.0 Reference: COQUITLAM GATE IP

Exhibit B-4, BCUC IR 1.9.1, 1.9.1.1, 1.6.8

Capacity of NPS 24 Coquitlam gate IP pipeline at 2070kPa

In response to BCUC IR 1.9.1 FEI states that with a NPS 24 Coquitlam Gate pipeline operating at 2070kPa, at the end of the 20 year planning period approximately 566,000 cubic metres per hour of peak demand would not be served.

In response to BCUC IR 1.9.1.1 FEI states that a NPS 24 pipeline at 2070kPa would not provide full redundancy on 12 days in a normal year.

In response to BCUC IR 1.6.8 FEI provides a 2034 Normal Year Peak Hour Load Duration Curve.

6.1 The 2034 Normal Year Load Duration Curve indicates a firm peak hour load of approximately 425,000 cubic metres per hour and a firm plus interruptible peak hour load of approximately 500,000 cubic metres per hour at Day 12. What is the estimated peak hour capacity of a NPS 24 Coquitlam Gate pipeline operating at 2070kPa in 2034-35?

Response:

The firm peak hour load for Day 12 of a normal year in 2034 is slightly lower than the values quoted above. The firm peak hour load is estimated to be 396,300 standard cubic metres per hour and the firm plus interruptible peak hour load is estimated to be 477,600 standard cubic metres per hour. Of this total flow into the IP System on Day 12, 446,400 standard cubic metres per hour would be required to flow west through the NPS 24 (2070 kPa) IP pipeline (see response to BCUC IR 2.5.1, paragraph 3 for an description of this division of flow).

The estimated capacity of the NPS 24 Coquitlam Gate IP Pipeline calculated using the forecasted 2034 load distribution and in the fashion described in creating the Pipeline Capacity Comparison Table provided in response to BCUC IR 1.3.2 (with Fraser Gate offline) would be just over 444,800 standard cubic metres per hour. On Day 12 of a normal year the estimated flow required through the NPS 24 (2070 kPa) Coquitlam Gate IP pipeline is slightly above the available capacity of the pipeline.

It should be noted that total load including the interruptible portion is considered in this assessment of resiliency. The reason for this is that on Day 12 of a normal year it is typical that interruptible customers are connected and using gas. In responding to an urgent situation, FEI does not have a means to shed this load as rapidly as a situation may require. This may result in potential customer losses if this situation occurs on any of the 12 coldest days of a normal year. A period of at least a few hours would be needed to be confident of curtailing the load used by interruptible customers.

In addition, FEI would like to emphasize that interruptible load is never considered as included in any design day peak hour scenarios or any scenarios short of a design day where interruptible customers are normally curtailed (i.e. in close to design day conditions where firm plus interruptible peak hour load would exceed the firm design day peak hour demand if not curtailed).

6.1.1 Please reconcile the estimated capacity provided in response to the previous question, to the response to BCUC IR 1.9.1.

Response:

BCUC IR 1.9.1 requested an estimation of how many customers would not be served and the corresponding load that could not be delivered to those customers by an NPS 24 (2070 kPa) IP pipeline under design peak hour conditions assuming there was no supply from Fraser Gate. The response provided by FEI considered how the NPS 24 (2070 kPa) IP pipeline would respond to the support from Fraser Gate being removed while the NPS 24 pipeline continued to be exposed to the demand requirements of all downstream customers.

The assessment indicated that such a condition would draw pressures in the pipeline below what would be required to sustain flow through any district station west of the IP lateral on Arden Avenue serving Simon Fraser University. The estimated design peak hour demand of the customers west of this location is approximately 566,000 standard cubic metres per hour and is in excess of the capacity of the NPS 24 pipeline of 444,800 standard cubic metres per hour provided in the response to BCUC IR 2.6.1. This situation, of sustained demand exceeding the pipeline's ability to provide the required flow and maintain minimum acceptable pressure, would create an unstable pressure collapse state as described in the response to BCUC IR 1.9.2. All the customers served by the downstream district stations would lose delivery pressure sufficient to operate their gas equipment.

7.0 Reference: COQUITLAM GATE IP

Exhibit B-4, BCUC 1.10.1

Capacity of NPS 30 Coquitlam gate IP pipeline at 1200kPa

In response to BCUC IR 1.10.1 FEI states that with a NPS 30 Coquitlam Gate pipeline operating at 1200kPa, at the end of the 20 year planning period approximately 586,300 cubic metres per hour of peak demand would not be served.

7.1 What is the estimated peak hour capacity of a NPS 30 Coquitlam Gate pipeline operating at 1200kPa in 2034-35?

Response:

The estimated capacity of the NPS 30 (1200 kPa) Coquitlam Gate IP Pipeline would be just over 327,400 standard cubic metres per hour. This estimate of capacity is calculated using the forecasted 2034 load distribution (with Fraser Gate offline) and in the fashion described in creating the Pipeline Capacity Comparison Table provided in the response to BCUC IR 1.3.2.

8.0 Reference: ALTERNATIVES DESCRIPTION

Exhibit B-4, BCUC 1.5.1

Pipeline design load methodology

In response to BCUC IR 1.5.1 FEI states: "The DDD (Design Degree Day) peak demand values are converted to an hourly demand by applying a peak hour factor."

8.1 Please provide the peak hour factors used for residential, commercial and other customer classes in the Metro area that are billed monthly.

Response:

The peak hour factor of 0.06 is applied to all customer classes whose peak hour demand is determined from monthly meter readings.

8.1.1 Please describe how the peak hour factors were determined.

Response:

The Peak Hour Factor (PHF) for FEI's Coastal System is determined from an assessment and comparison of both the 7-8am Monday to Friday peak hour average flows and the daily flows through Huntingdon Control Station into the Coastal Transmission System (CTS). Weekends and holidays are excluded from the assessment as peak hour consumption is consistently observed to be less relative to the daily demand than on work days. The assessment also includes data only within the peak winter period between November 15 and February 15 each year. The CTS supplies all of the FEI Lower Mainland distribution systems west of, but also including, the communities of Mission and Abbotsford.

From the daily and hourly values through Huntingdon, gas flowing through Eagle Mountain Compressor station to Vancouver Island and gas flowing to Burrard Thermal as well as the measured net change in line pack (net difference in gas contained within the CTS because of variations in pressure over time) is subtracted. Finally industrial demand based on daily nominations is subtracted from daily and peak hour values resulting in a daily and peak hour demand for each winter weekday for customers served by the CTS where a peak hour factor would be applied. A regression analysis of these daily values against the mean daily temperature and a regression of the peak hour values against the mean daily temperature results in a linear equation for each from which an estimate of the peak day demand for a

Design Degree Day (DDD) and peak hour demand for a DDD can be determined. The PHF is calculated from these derived values as:

PHF = Peak Hour Demand $_{(DDD)}$/Peak Day Demand $_{(DDD)}$

8.1.2 When were the peak hour factors for the Metro area last re-evaluated?

Response:

The peak hour factor for FEI's Coastal System including the Metro area was recently assessed in 2015.

8.1.3 To what extent have the peak hour factors changed over recent years?

Response:

The peak hour factor (PHF) estimate exhibits some variability from year to year. The calculated value since 2005 has ranged from 0.052 to 0.065 and averaging 0.058 with no clear upward or downward trend. Prior to 2004, the PHF for the Lower Mainland for several years had been 0.053. In 2004, it was determined that the current value was much lower than what assessments of daily and hourly flows in preceding periods were indicating. Based on those assessments, the PHF was adjusted upwards to 0.062 in 2004 but reassessed and lowered slightly to 0.060 the following year.

For consistent modelling results, it is disruptive to adjust the PHF year to year; therefore, FEI rarely adjusts the PHF unless a consistent trend for supporting a change is evident. As a result, the PHF factor applied in models of the Lower Mainland region has remained consistent at 0.060 since 2005.

8.2 Please confirm that the peak hour demand for a customer who has a firm contract demand is calculated based on the customer's contract demand, or explain otherwise.

Response:

Not confirmed. For determining distribution system capacity, the peak hour demand is determined for large commercial and industrial customers that receive firm delivery service (Rate Schedules 23, 5, 25) based on their observed historical peak hour consumption for process demand or historical peak hour consumption prorated to Design Degree Day conditions for temperature sensitive loads.

For large interruptible rate class customers that have a firm contract demand, such as that described in the response to BCUC IR 2.4.1, the peak hour demand is based on the firm Daily Transportation Quantity (DTQ) as outlined in the contract and the peak hour demand is calculated as 5% of the DTQ. The Tariff contains language stating that FEI is not obligated to deliver in any one hour more than 5% of the maximum quantity per day.

8.2.1 If the peak hour demand is not calculated as the firm contract demand divided by 24, please explain how the peak hour demand is determined.

Response:

Please refer to the response to BCUC IR 2.8.2.

9.0 Reference: ALTERNATIVES DESCRIPTION
Exhibit B-4, BCUC 1.5.1, 1.6.6
Pipeline design load methodology

In response to BCUC IR 1.5.1 FEI states: "Each community's annual load increment is determined by summing the product of each core rate class' account additions forecast for that year by the regional use per customer for that rate class."

In response to BCUC IR 1.6.6 FEI states: "Each community's annual load increment is determined by summing the product of each core rate class' account additions forecast for that year by the regional UPC (peak hour use per customer) for that rate class. It is assumed the UPC values remain constant over the planning period."

9.1 Please confirm that the term "annual load increment" as used in this context refers to the annual increase in peak hour load, rather than the yearly increase in annual load (i.e. increase in total load for the year), or explain otherwise.

Response:

Confirmed, the term "annual load increment" in the responses to BCUC IR 1.5.1 and BCUC IR 1.6.6 refers to the annual incremental increase in peak hour load for each community.

9.2 Considering that the annual use per customer continues to decline, particularly for residential customers, please explain why the utility assumes that the peak hour use per customer will remain constant over the 20-year period.

Response:

Although FEI has seen a reduction in the annual use per customer (UPC) in some customer classes the impact on peak hour demand has not followed the same declining trend. As stated on page 72 of FEI's 2014 Long Term Resource Plan:

"FEI recognizes that uncertainty remains about how different annual trends might be reflected in peak demand. Some end-uses that result in declining annual demand may actually increase peak demand;

Some end-uses may not cause any change in peak demand; and others may cause a reduction in peak demand. "

For example, FEI has observed the following in the Metro Vancouver area:

- Residential peak hour UPCs for Vancouver, Burnaby and New Westminster have increased by just over 2% from 2010 to 2015, while in Coquitlam, North Vancouver and West Vancouver the residential peak hour UPC has declined by approximately 2%.
- Small Commercial customers have seen an increase in peak hour UPC of 20-30% in the same areas while larger commercial account peak hour UPCs are recording increases from 0% to 6% over the same period.

At present, given the variability in the trending of the peak hour UPC and considering that the determination of peak hour UPC is an annual process while peak hour load forecasts are adjusted regularly to reflect the most current information on peak hour demand, FEI considers it reasonable that the Peak hour UPC remains constant over the planning period.

Refer also to the response to BCUC IR 2.9.2.1.

9.2.1 Please identify the reasons why residential annual use per customer has been declining, and discuss whether each reason is or is not expected to have a similar impact on peak hour use per customer.

Response:

The decline in annual residential use per customer (UPC) is attributable to a variety of factors, including technological advances and energy efficiency improvements, building codes, size and type of homes being built, and type of appliances being installed in these homes.

Regarding peak hour UPC, there are a number of reasons why peak hour UPC may follow an alternate trend from the declining annual demand. Peak hour UPC can be influenced upwards or downwards depending on the specific equipment or consumption patterns that become predominant in driving annual UPC downward. Smart thermostats, for example, can reduce off peak consumption when residents are asleep or at work, but concentrate demand in the hours when residents are coincidentally rising for the day or returning from work. Increasing thermal efficiency of appliances and general improvements to insulation and windows in dwellings can be expected to reduce peak hour UPC. Thermal energy systems, such as air source heat pumps, that rely on natural gas only as a back up for peak demand may again increase peak hour consumption while maintaining a low annual demand.

9.3 For each of the past five years for Lower Mainland service area core gas customers, what number of customers, normal annual load, design peak day load and design peak hour load has FEI used for gas supply planning?

Response:

The following information was used for gas supply planning for core customers (Rate Classes 1-7) in the Lower Mainland service area over the last five years. All values included in the following table represent forecast amounts. Please note that this information is based on the gas supply planning year, which starts each November 1 and ends each October 31 of the following year.

	2010/11	2011/12	2012/13	2013/14	2014/15
Number of Customers	582,199	586,706	590,220	582,199	584,979
Normal Annual Load (TJ/Yr)	85,977	85,977	85,653	87,826	85,738
Design Peak Day (TJ/Day)	926	908	900	892	892

Note: LML region only.

Gas supply planning does not consider design peak hour loads in its planning requirements.

C. PIPELINE ROUTING - COQUITLAM GATE

10.0 Reference: COQUITLAM GATE - ROUTE SELECTION PROCESS

Exhibit B-4, BCUC 1.15.1

Changes to the approved pipeline route

In response to BCUC IR 1.15.1 FEI explains:

> FEI is not seeking approval of a segmented Coquitlam Gate IP Project. FEI is seeking approval of a CPCN to construct and operate the entire Coquitlam Gate IP Project based on a routing that the Commission determines is in the public interest. Based on the information available to FEI at the time of the Application, FEI has proposed a preferred route that meets this requirement. Should another route emerge as a more suitable route alignment based on the Company's evaluation of information available subsequent to the filing of the Application, but prior to the close of the evidentiary record in this proceeding, such information will be provided to the Commission to support any proposed change.
>
> Furthermore, if an approved routing was no longer considered feasible during the detailed engineering or construction stage and another route emerged as a feasible alternative subsequent to the CPCN approval (i.e. after the close of the current regulatory proceeding), FEI believes that a limited review by the Commission of the newly proposed route and changes (if any) resulting from the route change may be conducted based on the evidence provided by the Company. The overall need for the Projects, along with many other aspects of the Projects, would have already been accepted by the Commission as being in the public interest. If the situation described above does occur, the Company will propose a regulatory review process that will provide an efficient and effective review of the proposed change.

10.1 Assuming the Commission determines and approves a specific routing, please provide and justify the criteria FEI would propose the Commission use that would trigger a detailed Commission review of a proposed route change.

Response:

FEI has selected a preferred route for the Coquitlam Gate IP pipeline based on available information, which has been presented in the Application and the Evidentiary Update.

Should the Commission grant CPCN approval for the Project based on this route, FEI will proceed with detailed design (routing and engineering) to achieve a fully engineered and defined final pipeline route alignment. As discussed in section 3.3.4.8 of the Application, any changes to the preferred route, and the final locations for any facilities along the pipeline route, will then be confirmed during the detailed design process.

In the event that the Commission approved routing is no longer considered feasible and another route emerges as a feasible alternative after detailed design, FEI proposes to update the Commission about the alternative route, including any Project cost and schedule impacts and additional consultation that may be required. FEI will then propose an appropriate level of Commission review of the new route based on the nature and scope of the change. FEI expects that the requirement for further review would be based on the extent of the proposed route change. While a minor change may require little or no review, a significant change may require a more detailed Commission review.

11.0 Reference: SECTION 6 – SPRINGER AVENUE TO BOUNDARY ROAD
Exhibit B-1-6, Appendix A-17, Section 1.2, p. 7
Options A and B pipeline route alignments

On page 7 of Appendix A-17 of the Evidentiary Update FEI explains:

> Lougheed Highway Option B adopts a similar alignment to Option A from Springer Avenue to Madison Avenue. Just east of Gilmore Avenue Option B moves from the west bound lanes to the east bound lanes to increase the distance from the BC Hydro substation west of Gilmore Avenue. It is necessary to maximize the distance between the buried steel pipeline and the substation infrastructure to mitigate the risk to the pipeline from electrical faults within the electrical substation. Option B turns north along Boundary Road and then west along East 1st Avenue where the alignment interfaces with the proposed route through Vancouver for Section 7.

11.1 Please provide the engineering studies, calculations, reports and/or standards that were used to determine it is necessary to increase the distance from the BC Hydro substation.

Response:

The Coquitlam Gate IP pipeline will be almost entirely located within municipal road allowances – in many cases where there is also existing BC Hydro electrical infrastructure (overhead power lines and buried power cables). Therefore, in 2014 FEI and BC Hydro established a joint project technical working group to identify and address technical issues resulting from potential mutual impacts concerning both BC Hydro infrastructure and the proposed Project, including separation distances from BC Hydro infrastructure.

The Lougheed Highway Option B alignment passes by the BC Hydro Horne Payne electrical substation located at the intersection of Gilmore Avenue and Lougheed Highway in Burnaby. The required separation distance from this BC Hydro infrastructure was discussed by the technical working group during discussions related to the Evidentiary Update route evaluation for route corridor Section 6.

BC Hydro communicated to FEI that its corporate standard for separation distance from the Horne Payne substation, to adjacent buried steel gas pipelines, would be 40 metres from the outer perimeter fence bounding the substation site. To meet this requirement the Lougheed Highway Option B is routed along the southern edge of Lougheed Highway as it passes the Horne Payne substation. Although this provides a separation distance of only 35 metres, due to existing development along the south side of Lougheed Highway at this location, the separation distance was confirmed by BC Hydro as being acceptable.

11.2 If going from the westbound lanes to the eastbound lanes and back, were not required, what impact would this have on the relative route evaluations and rankings, and costs?

<u>Response:</u>

If going from the westbound lanes to the eastbound lanes and back was not required, it would avoid pipeline construction across Lougheed Highway (from the north side to the south side and back to the north side) at two locations between Gilmore Avenue and Boundary Road. There would be a negligible reduction in pipeline length and, as the construction would be typical open trench along this section of route, there would be a negligible overall reduction in construction complexity and cost.

Traffic management complexity would be reduced somewhat as a result of the pipeline construction not having to cross from the westbound lanes on Lougheed Highway to the east bound lanes and back again; however, given the magnitude of potential traffic impacts from pipeline construction on Lougheed Highway Option B from Madison Avenue to Boundary Road and then along Boundary Road to East 1st Avenue, the reduction in traffic impacts from the avoided pipeline construction across Lougheed Highway at these two locations would also be negligible.

As a result, there would be no change to the overall relative route evaluation and rankings and a negligible reduction in construction costs.

11.3 For Option A and/or the Original Preferred Option is new right-of-way required immediately East of Graveley and Boundary?

<u>Response:</u>

This response addresses BCUC IRs 2.11.3, 2.11.3.1, 2.11.3.1.1 and 2.11.3.1.2.

For Lougheed Highway Option A and/or the Original Preferred Option there is no new right of way required East of Graveley Street between Boundary Road and Ingleton Avenue. The Lougheed Option A and/or the Original Preferred route alignment is located within Graveley Street municipal road allowance.

11.3.1 If yes, are the acquisition costs, risks and impacts associated with the right-of-way included in the route option evaluations for section 6?

Response:

Please refer to the response to BCUC IR 2.11.3.

11.3.1.1 If yes, please explain how.

Response:

Please refer to the response to BCUC IR 2.11.3.

11.3.1.2 If not, please explain why not and compare Options A, B and the Original Preferred Option, if these right-of-way costs, risks and impacts are included in the comparison.

Response:

Please refer to the response to BCUC IR 2.11.3.

11.4 Please confirm, otherwise explain, that the proposed Option B pipeline route evaluation was performed on a route that goes north on Boundary to East 1st Avenue, then immediately turns west. The route does not continue north through Boundary and East 1st to Graveley, then turn west on Graveley, then turn south through a right-of-way, then turn west on East 1st.

Response:

Confirmed. The Lougheed Highway Option B evaluation was performed on a pipeline route that travels north along Boundary Road from Lougheed Highway to East 1st Avenue and then immediately turns west onto East 1st Avenue. The route does not continue north through Boundary Road and East 1st Avenue to Graveley Street.

11.4.1 If the route evaluation does consider a pipeline continuing through Boundary and East 1st to Graveley etc…please explain why.

Response:

Please refer to the response to BCUC IR 2.11.4.

On page 93 of the Application FEI states:

> …the Coquitlam Gate IP project may involve the acquisition of new land and access rights for an approximate 70 meters of the proposed route alignment between Boundary Road and Highway No. 1. FEI will finalize any new land and access right negotiations once approval of this Application is received.

On page 69 of Appendix A-17 FEI shows the proposed Option A pipeline route following Graveley, then Boundary and then East 1st.

11.5 Please confirm, otherwise explain, that Route Option A and the Original Preferred Option are no longer considering a route along Graveley west of Boundary road.

Response:

This response is being filed confidentially under separate cover, as it relates to ongoing land acquisition negotiations, the disclosure of which may impact FEI's negotiating position.

11.6 Please confirm, otherwise explain, that acquisition of new land and access rights west of Boundary is no longer being considered. If it is, please explain why.

Response:

Please refer to FEI response to BCUC IR 2.11.5 which is being filed confidentially under separate cover.

12.0 Reference: LOUGHEED ROUTE OPTION

Exhibit B-1-6, Section 2.3.2.2, p. 10

Traffic

On page 10 of the Evidentiary Update FEI explains:

> Further routing analysis re-evaluated the route option along Lougheed Highway, primarily in terms of reduced traffic disruption considerations and the impact on the socio-economic criteria. Relative to the socio-economic score presented in section 2.5.1.2 of the Application, the Lougheed Highway route option is now considered to have a moderate impact (good route choice) compared to the very high negative impact (unviable route choice) score originally assigned which was based on the understanding, at that time, that full closure of the west bound lanes would not be feasible due to significant deterioration in traffic performance.

On page 6 of the Evidentiary Update FEI quotes the City of Burnaby: "Following deliberation by City Council, the City has determined that the traffic disruptions from the Lougheed Highway alignment are acceptable…"

On page 15 of Appendix A-18-5 FEI's consultant provides a comparison of the base and Route Option A construction scenario 1, 2 and 3 average travel times (minutes/vehicle):

	AM		PM	
Lougheed Highway				
Route Option/Construction Scenario	**EB**	**WB**	**EB**	**WB**
Base	9	10	10	10
Route Option A Construction Scenario 1	14	46	132	40
Route Option A Construction Scenario 2	9	41	65	44
Route Option A Construction Scenario 3	10	21	31	25

12.1 Please confirm, otherwise explain, that full closure of the west bound lanes is still expected during construction and FEI still expects significant deterioration in traffic performance.

<u>Response:</u>

This response addresses BCUC IRs 2.12.1, 2.12.2 and 2.12.3.

Full closure of segments of the Lougheed Highway west bound lanes is still expected during construction of the Coquitlam Gate IP Project along Lougheed Highway from Bainbridge Avenue to Madison Avenue in Burnaby. FEI also still anticipates that construction of the proposed pipeline along Lougheed Highway will result in significant traffic disruption and does not expect reduced traffic disruption on Lougheed Highway compared to when the Application was originally filed. However, based on the original preliminary traffic impact assessments presented in Appendix A-18-2 and A-18-5 of the Application, FEI expected that the impacts from traffic disruption during the proposed pipeline construction would also result in significant deterioration in traffic performance, and that the City of Burnaby, as the responsible road agency, would therefore not permit pipeline construction on Lougheed Highway.

Compared to when the Application was originally filed with the Commission, FEI has completed further detailed traffic impact assessments, and further engaged City of Burnaby staff and Council, to better understand the potential deterioration in traffic performance with regard to travel time delays and queuing at intersections during construction of the proposed pipeline along Lougheed Highway. As a result of this additional information, FEI does not expect that the deterioration in traffic performance will be as significant as previously expected and, after review by the City of Burnaby of the further traffic assessment reports, was advised by the City that construction on Lougheed Highway would be permitted from Bainbridge Avenue to Madison Avenue. The traffic performance deterioration, in terms of travel time delays and queuing at intersections for various pipeline construction scenarios for the new preferred route (Lougheed Highway Route Option A), is detailed in the traffic assessment report in Appendix A-18 of the Evidentiary Update, and summarized in the table in the preamble to this IR (Table 11 from A-18 of the Evidentiary Update).

The Lougheed Highway Route Option A Construction Scenario 1 is considered a worst case with lane reductions on Lougheed Highway all the way from Bainbridge Avenue to Madison Avenue. These full corridor lane reductions are however not expected to occur all at the same time as the pipeline construction will be staged to take place only on shorter sections of Lougheed Highway. With staged construction work, only a few intersections would be affected at any one time, except for when construction is taking place in the Delta Avenue to Gilmore Avenue section where the entire section would be subjected to lane reductions. This is required due to the inability to safely switch traffic over the raised median island between the TransLink SkyTrain piers. The travel times for staged construction would therefore be markedly less. Since the work will be staged, an alternative construction scenario that focused on construction work in the critical area from a traffic perspective was developed.

Route Option A Construction Scenario 2 addresses this arrangement, and travel times generally reduce compared to the Route Option A Construction Scenario 1 because the extent of lane closure is less. However, travel times are still significantly longer than the Base travel times. The traffic analysis also reviewed existing traffic volume demands on Lougheed Highway and the available capacities at the intersections.

Route Option A Construction Scenario 3 involves detouring the excess volume of traffic off Lougheed Highway at each intersection, at which point the corridor could be expected to function in a reasonable manner. The travel times generally reduce compared to Route Option

A Construction Scenario 2 because the volume demands are less; however, travel times are still longer than the Base times.

The Route Option A Construction Scenario 3 analysis has assumed the detouring of traffic volumes up to 500 vehicles per hour. The only viable alternative route parallel to Lougheed Highway, between Gaglardi Way and Boundary Road, is Highway 1. Highway 1 however also experiences congestion in the same direction as Lougheed Highway during morning and afternoon peak periods. Therefore, while Route Option A Construction Scenario 3 travel times on Lougheed Highway are expected to be tolerable, there will still likely be traffic performance deterioration along Lougheed Highway during the proposed pipeline construction. FEI has therefore, as a result of this further analysis and further consultation with the City of Burnaby, re-evaluated the expected traffic disruption impacts and considerations (deterioration in traffic performance) presented in the routing analysis in Appendix A-17, and summarized on page 10 of the Evidentiary Update.

Compared to Lougheed Highway Route Option A, the impacts from the Coquitlam Gate IP pipeline construction along the Original Preferred Route, in terms of travel time delays and queuing on Lougheed Highway, have not been assessed to date. The traffic management and impact considerations for the Original Preferred Route on Broadway are presented in the Preliminary Traffic Management Review Report in Appendix A-18-2 of the Application. This report identified the number of cars which currently use Broadway and, because the pipeline construction on Broadway would restrict through traffic, the numbers of cars which would therefore have to divert from Broadway onto Lougheed Highway during the pipeline construction. However, it would be expected that the impacts from pipeline construction to traffic on Lougheed Highway in terms of travel time delays would have been minimal given that the Original Preferred Route did not follow the Lougheed Highway alignment. As such, the travel times on Lougheed Highway during construction of the Original Preferred Route would have been very similar to the Base travel times in the table above. The travel times for Route Option A could be the same as Route Option A Scenario 2 (which assumes no traffic diversion, i.e. worst case), but is more likely to be similar to Route Option A Scenario 3 (which assumes traffic diversion, i.e. likely case).

12.2 Please confirm, otherwise explain, that compared to when the Application was originally filed with the Commission, FEI does not now expect reduced traffic disruption along Lougheed. If FEI does now expect reduced traffic disruption, please explain why.

Response:

Please refer to the response to BCUC IR 2.12.1.

12.3 Please provide and compare the average travel times FEI expects during pipeline construction of the Coquitlam Gate IP pipeline assuming Route Option A and FEI's proposed construction scenario, and assuming the Original Preferred Alternative.

Response:

Please refer to the response to BCUC IR 2.12.1.

D. COST - COQUITLAM GATE

13.0 Reference: CLASS 3 ESTIMATES OF EACH PREFERRED ROUTE SEGMENT

Exhibit B-4, BCUC 1.15.1, 1.15.3, 1.16.1

Comparing the estimated costs of each section of pipeline

In response to BCUC IRs 1.15.1 and 1.15.3 FEI explains: "FEI has not provided a Class 3 estimate for each section of the preferred route as the Company believes it would not be informative or necessary at this stage, particularly in light of the costs and resources required to develop these additional Class 3 estimates."

In response to BCUC IR 1.16.1 FEI explains: "FEI prepared a cost estimate consistent with an AACE Class 3 level of project definition for the route alignment identified from the non-financial analysis, as a starting point for the financial analysis. The estimate was prorated on length and construction factors to develop an estimated construction cost for each segment."

13.1 Recognizing that this information has already been requested and was not provided, to ensure an appropriate cost estimate for comparing route alternatives, please provide the estimated construction cost for each of the seven sections of the preferred route to an AACE Class 3 level (e.g. section 1 = $10M, section 2 = $15M, 3 = $20M, etc…).

Response:

This response is being filed confidentially under separate cover, for the reasons described in the cover letter to the Application (Exhibit B-1) regarding Cost Estimates.

14.0 Reference: CLASS 4 ESTIMATES OF THE ALTERNATIVE ROUTES

Exhibit B-4, BCUC 1.16.1; BCUC CPCN Guidelines

Comparable and accurate cost estimates

In response to BCUC IR 1.16.1 FEI explains: "…AACE Class 5 estimates were also developed for each route alternative, and these cost estimates formed the basis of the financial route analysis."

The BCUC CPCN Guidelines state that cost estimates used in the economic comparison should have, at a minimum, a Class 4 degree of accuracy.[7]

14.1 Please provide the estimated construction cost for each route alternative used in the financial route analyses to an AACE Class 4 level (e.g. section 5 alt. 1 = $50M, section 5 alt. 2 = $55M, etc…).

Response:

Please refer to the response to BCUC IR 2.13.1.

14.2 Please perform the financial route analysis using the Class 3 estimate for each section of the preferred alternative and the Class 4 estimates of each alternative route.

Response:

Please refer to the response to BCUC IR 2.13.1.

[7] Order G-50-10, Appendix A, p. 6, Order G-20-15, Appendix A, p. 4.

15.0 Reference: CLASS 4 ESTIMATES OF THE ALTERNATIVE 4

Exhibit B-1, pp. 35, 38; BCUC CPCN Guidelines; Exhibit B-1-6, p. 17

Comparable cost estimates

On pages 35 and 38 of the Application FEI states it has a Class 3 estimate for the preferred alternative (Alternative 6) and a Class 4 estimate for Alternative 4.

The BCUC CPCN Guidelines state that cost estimates used in the economic comparison should have, at a minimum, a Class 4 degree of accuracy.[8] [Emphasis added]

On page 17 of the Evidentiary Update FEI provides a revised financial and operational risk comparison of Alternatives 4 and 6.

15.1 Considering the only difference between Alternative 4 and the preferred alternative is pipe size, please update Alternative 4 to a Class 3 estimate.

Response:

The AACE Class 4 estimate for Alternative 4 (NPS 24 at 2070 kPa) included in the Evidentiary Update has been updated to an AACE Class 3 estimate. Accordingly, the maturity level of the Alternative 4 project definition deliverables has increased to the AACE Class 3 level of project definition requirements.

The Alternative 4 AACE Class 3 cost estimate has increased by approximately 7% compared to the Alternative 4 AACE Class 4 estimate filed with the Evidentiary Update. The Alternative 4 AACE Class 4 estimate had included cost components that were based on the Alternative 6 AACE Class 3 estimate, including for example pro-rated pipeline materials costs and construction productivity assumptions. The Alternative 4 AACE Class 3 estimate is now based on specific project scope definition deliverables, including vendor materials quotes and a construction execution plan. The NPS 24 pipeline construction productivity, including trench excavation, welding, pipe handling, and trench backfill is now expected to be very similar between the NPS 24 and NPS 30 pipeline sizes. This further cost estimate analysis of the Alternative 4 NPS 24 scope has reduced the cost difference between the NPS 24 pipeline (Alternative 4) and the preferred NPS 30 pipeline (Alternative 6). The Alternative 4 AACE Class 3 total estimated cost is now within approximately 4% of Alternative 6 AACE Class 3 total estimated cost.

In line with the increase in the capital costs at an AACE Class 3 level, the Levelized Rate and the PV of the Cost of Service for 60 years has also increased by 7%.

[8] Ibid.

The financial and operational risk comparison of Alternative 4 (NPS 24 at 2070 kPa) and Alternative 6 (NPS 30 at 2070 kPa) has also been updated using the Alternative 4 AACE Class 3 estimate and presented in the response to BCUC IR 2.15.2.

Table 2-2 from the Evidentiary Update filed on April 30, 2015 is provided below with revisions to Alternative 4 based on a Class 3 AACE Estimate of Accuracy. The Class 4 estimate for Alternative 4 as well as the Class 3 estimate for Alternative 6 (the preferred alternative) have also been included for comparison purposes.

Evidentiary Update Revised Table 2-2: Updated Coquitlam Gate IP Project Financial Comparison

	Alternative 4 Install NPS 24 pipeline at 2070 kPa Lougheed Route	**Alternative 4 Install NPS 24 pipeline at 2070 kPa Lougheed Route**	**Alternative 6 Install NPS 30 pipeline at 2070 kPa Lougheed Route**
AACE Estimate Accuracy	***Class 4***	***Class 3***	***Class 3***
Total Direct Capital Cost excl. AFUDC & includes Abandonment / Demolition (2014 $millions)	179.671	191.952	199.053
Total Direct Capital Cost excl. AFUDC (As-spent $millions)	207.958	222.261	230.474
AFUDC (as spent $millions)	11.254	11.896	12.351
Total As-spent includes Abandonment / Demolition & AFUDC ($millions)	219.212	234.157	242.825
Annual incremental gross O&M (2014 $millions)	0.055	0.055	0.055
Levelized Rate Impact – 60 Yr. ($ / GJ)	0.090	0.096	0.100
PV Incremental Cost of Service – 60 Yr. ($millions)	266.379	284.207	297.183

15.2 Please update the financial and operational risk comparison of Alternatives 4 and 6 using the updated Alternative 4 Class 3 estimate.

<u>Response:</u>

With Alternative 4, NPS 24 at 2070 kPa, at an AACE Class 3 Estimate of Accuracy, the Present Value of Operational Risk plus the Present Value of the Incremental Cost of Service for 60 Years ($317.514 million) exceeds the value for Alternative 6, install NPS 30 pipeline at 2070 kPa ($297.183 million).

Table 2-3 from the Evidentiary Update filed on April 30, 2015 is provided below with revisions to Alternative 4 results from using Project costs based on a Class 3 AACE Estimate of Accuracy.

Evidentiary Update Revised Table 2-3: Updated Coquitlam Gate IP Project Financial and Operational Risk Comparison

		Alternative 4 Install NPS 24 Pipeline at 2070 kPa Lougheed Route	**Alternative 6 Install NPS 30 Pipeline at 2070 kPa Lougheed Route**
1	Potential Operational Risk Reduction Per Appendix A-10 (2014 $millions/year)	2.456	2.456
2	Operational Risk Reduction (Coquitlam Gate IP Pipeline and Cape horn to Coquitlam TP complete) (2014 $millions/year)	0.352	2.456
3	Operational Risk Reduction (%)	14.34%	100.0 %
4	Remaining Operational Risk (2014 $millions/year)(line 1-Line2)*	2.104	0
5	PV Remaining Operational Risk – 60 Yr ($millions)	33.307	0
6	PV Incremental Cost of Service – 60 Yr ($millions)	284.207	297.183
7	PV Remaining Operational Risk + PV Incremental Cost of Service – 60 Yr ($millions)	317.514	297.183

** Based on potential operational risk in line 1*

E. RISKS - COQUITLAM GATE

16.0 Reference: ECONOMIC CONSEQUENCE ANALYSIS

Exhibit B-1-1, Appendix A-5, pp. 1, 8-9, 21; Exhibit B-1-4, pp. 41, 186; Exhibit B-6,

CEC IR 1.83.4

Worst case scenario and the financial and operational risk comparison

In Appendix A-5, the economic consequence analysis report prepared for FEI, the author explains that "the scope of this work is to provide a quantitative estimate of the economic consequences of a credible worst case disruption in gas supply"[9] and "[o]utages and interruptions of the sort described in this report are rare events."[10]

The author also explains that "[w]hile we all may be aware of a worst possible outcome, or a best possible outcome, most decisions from a societal perspective are not made solely on the extremes."[11]

In response to CEC IR 1.83.4 FEI states that "Over the past 10 years, FEI has experienced 5 outages ranging in size from 442 to 1,297 customers. The relight period of these outages has been 2-3 days."

Table 4.1 on page 21 of Appendix A-5 shows the summary of sensitivity results, which includes a scenario for permanent revenue loss, two week response delay, cold weather with an additional 20% increment in gas usage, and reducing the vulnerability of critical elements of gas use by 10%, respectively.

On page 186 of the Errata filed in Exhibit B-1-4 FEI provides a revised financial and operational risk comparison of Alternatives 4 and 6:

9 Exhibit B-1-1, Appendix A-5, p. 1.
10 Ibid., p. 8.
11 Ibid., p. 9.

Table 9-3: Coquitlam Gate IP Project Financial and Operational Risk Comparison

		Alternative 4 Install NPS 24 Pipeline at 2070 kPa	Alternative 6 Install NPS 30 Pipeline at 2070 kPa
1	Potential Operational Risk Reduction Per Appendix A-10 (2014 $millions/year)	2.456	2.456
2	Operational Risk Reduction (Coquitlam Gate IP Pipeline and Cape horn to Coquitlam TP complete) (2014 $millions/year)	0.352	2.456
3	Operational Risk Reduction (%)	14.34%	100.0 %
4	Remaining Operational Risk (2014 $millions/year)(line 1-Line2)*	2.104	0
5	PV Remaining Operational Risk – 60 Yr ($millions)	33.307	0
6	PV Incremental Cost of Service – 60 Yr ($millions)	257.908	298.714
7	PV Remaining Operational Risk + PV Incremental Cost of Service – 60 Yr ($millions)	291.215	298.714

16.1 Please confirm, otherwise explain, that the operation risk reductions included in Table 9-3 are based on the economic consequence analysis report which assumes a worst case scenario as outlined in Appendix A-5.

Response:

H.J. Ruitenbeek Resource Consulting provides the following response:

The operational risk reductions included in Table 9–3 are *inter alia* based on the economic consequence report in Appendix A-5. The specific economic consequences are entitled the "Reference Case" in that report, and are characterized (page 1) as the "credible worst case" for economic damages in the event of disruption to service. The preamble to this question (Exhibit B-1-1, Appendix A-5, p. 1.) correctly provides the citation, which characterizes the "credible worst case disruption". The operational risk reductions included in Table 9–3 also rely on estimates of the likelihood of such a disruption of service event; the likelihoods are provided in Appendix A-10 of Exhibit B-1-1.

16.2 Please confirm, otherwise explain, that it would be a rare event for a worst case scenario to occur. Please provide an estimate of the probability of the worst case scenario occurring.

Response:

H.J. Ruitenbeek Resource Consulting provides the following response:

The preamble to this question correctly provides the citation (Exhibit B-1-1, Appendix A-5, p. 8) in the evidence, which characterizes that all "[o]utages and interruptions of the sort described in this report are rare events."

The 'rarity' is a subjective interpretation, but it arises from a combination of (i) the likelihood of pipeline failure, and (ii) that the failure occurs during conditions of high energy demand (the heating season). The first parameter – the likelihood of pipeline failure – is primarily responsible for the subjective rarity of the event. For example, as illustrated and confirmed in the response to BCUC IR 2.16.10, the failure frequency in Segment 1 downstream of Fraser Gate is estimated to be 0.00195 failures per year. This failure frequency is equivalent to stating that such a failure is expected statistically to occur approximately once in any 500 year period. This is subjectively characterized as "rare". The *contingent likelihood* of a failure occurring during the heating season (i.e., that contingent upon such a rare failure happening in a given year, it would occur during a cold period) is not in isolation a rare event. For example, representative load shape of residential demand in the Lower Mainland suggests that a 4 month period of consumption (November-February) represents 50-65 percent of annual demand depending upon locality. A prudent decision-maker would consider that an outage during a peak demand period is a reasonable basis for evaluating economic consequences.

An "estimate of the probability of a worst case scenario occurring" cannot be provided. Such a probability is the product of two numbers: (i) the failure frequency; and (ii) the contingent probability that the consequences occur within the set of outcomes that fall into a class characterized as "worst case". Although the failure frequencies are quantifiable using procedures as described in Appendix A-10, the contingent probability of the consequences has not and cannot be estimated. To estimate the latter (the contingent probability of the consequences), the underlying probability distribution of consequences needs to be known. Such probability distributions of consequences for rare events – which we might call "gas pipeline failures in metropolitan areas with disruptions of long duration" – are generally not identifiable in any statistically reliable fashion. While models might be developed, they cannot be tested against experience because the consequences are likely to depend on factors such as actual outage numbers, time of outage, time of year, mitigation measures previously in place, and others. Statistical approaches would need to identify and control for such factors across a statistically significant sample, and measure actual consequences in economic terms that can be normalized across the samples. For "one in 500 year" events this is not tractable. It is thus not possible to determine the probability distribution of the consequences. In such circumstances, an approach of "credible worst case disruptions" – accompanied by sensitivity scenarios – is appropriate.

16.3 Based on FEI's experience with outages in the past, please confirm, otherwise explain, that should an outage occur, it is more probable for it to be less severe than the reference case in the economic consequence analysis.

Response:

H.J. Ruitenbeek Resource Consulting provides the following response:

This statement cannot be confirmed. The outages that FEI has experienced over the past ten years are not scalable to the reference case considered in this analysis. Outages may occur for a number of reasons.

As described in response to BCUC IR 2.16.2, the probability distribution of consequences for unplanned outages that arise from gas pipeline failures cannot be identified due to the rarity of such failures: the position of the credible Reference Case within the probability distribution is therefore not identifiable.

FEI further adds the following comment:

FEI can confirm that the five outages with which it has experience in the past ten years (the response to CEC IR 1.83.4) resulted in consequences that were less severe than those in the Reference Case.

16.4 The sensitivity analysis considers five scenarios, four of which assumes a scenario that is worse than the reference case for the economic consequence analysis. Please comment on whether FEI considers sensitivity analysis should, in addition to scenarios that consider more severe consequences, include scenarios that are less severe than the reference case.

Response:

H.J. Ruitenbeek Resource Consulting provides the following response:

Please refer to the response to CEC IR 1.85.1.

16.5 Please compare Alternatives 4 and 6 using a P90 case scenario (90% probability that it would not occur), explain what conditions are included in a P90 case scenario, and please provide an estimate of the probability that the P90 case scenario would occur.

Response:

H.J. Ruitenbeek Resource Consulting provides the following response:

The identification of a P90 scenario is not possible, nor necessarily relevant, to the overall risk analysis. A P90 scenario normally refers to a threshold condition (or conditions) within a cumulative probability distribution of a series of outcomes. As described in the response to BCUC IR 2.16.2, the conditional probability function for consequences is not identifiable, and therefore any P90 (or other such as P10 or P50) threshold or conditions cannot be described. Therefore, no comparison can be made. Also, a P90 threshold is not relevant in the case of the failure frequency (FF) analysis as the FFs are explicitly identified in Appendix A-10. For example, as illustrated and confirmed in the response to BCUC IR 2.16.10, the failure frequency in Segment 1 downstream of Fraser Gate is estimated to be 0.00195 failures per year. This failure frequency is equivalent to stating that such a failure is expected statistically to occur approximately once in any 500 year period. It can also be shown that such a failure frequency implies that there is a 90% probability that no such failures will occur in a 54 year period.

16.6 Please provide a project financial and operational risk comparison of Alternatives 4 and 6 assuming a P90 case scenario.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

As described in the response to BCUC IR 2.16.5, a comparison cannot be provided.

16.7 Please confirm, otherwise explain, that from a societal perspective, the use of a P90 scenario for decision making, as opposed using the worst case scenario (extreme), would be more appropriate.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

For reasons described in the response to BCUC IR 2.16.5, a "P90 scenario" is not identifiable, and the Reference Case scenario used in the analysis is appropriate from a societal perspective in the context of a quantitative risk assessment. The Reference Case is characterized as a credible worst case disruption. The Reference Case is not described as "extreme"; sensitivity analyses that are provided for information purposes cover some instances in which consequences would be worse than those estimated in the Reference Case.

FEI further adds the following comment:

FEI notes that a societal perspective must also consider factors other than just the quantitative risk assessment. This assessment provides input into determining the broader societal interest, but is not the only factor.

In footnote 3 of Table 3-1, on page 41 of the Errata filed in Exhibit B-1-4, FEI explains: "Under this alternative, a failure upstream, at, or downstream of the Fraser Gate Station during mid-winter conditions will impact up to 171,000 customers that could result in an economic impact in excess of $320 million."

16.8 Please confirm, otherwise explain, that the $320 million potential economic impact is based on the worst case scenario outlined in Appendix A-5.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

$320 million is based on a case outlined in Appendix A-5 as the "Reference Case: a credible worst case disruption". This does not reflect the extreme case noted in Appendix A-5 of Exhibit B-1-1.

16.9 Please provide a similar estimate of the potential economic impact assuming the P90 scenario.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

As described in the response to BCUC IR 2.16.5, a similar estimate cannot be provided.

16.10 Please confirm that the probability of failure at this worst case location is 0.00195 failures per year.

Response:

Dynamic Risk Assessment Systems Inc. provides the following response:

As outlined in Table 4 of Appendix A-10 of Exhibit B-1-1, Segment 1, downstream of Fraser Gate has an estimated failure frequency of 0.00195 failures per year.

16.11 Please provide the probability of a failure occurring at this location and it occurring during the worst case scenario conditions.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

This question is interpreted as referring to the Reference Case conditions for the economic consequences ("credible worst case" disruption). The concurrent probability of a failure at this location has not and cannot be determined because no probability distribution of costs has been estimated for the economic consequences, for the reasons outlined in the response to BCUC IR 2.16.5.

17.0 Reference: ECONOMIC CONSEQUENCE ANALYSIS

Exhibit B-1-1, Appendix A-5, p. 18; FEU-2012-2013 RRA proceeding, Exhibit B-1, p. 92

Revenue loss

On page 18 of Appendix A-5 FEI's consultant states:

> FEI will experience direct revenue losses through two mechanisms: (i) the outage event will reduce sales revenues depending on the duration of the outage, the estimated demand during the outage by a customer, and the applicable tariff (including cost of service) but excluding commodity cost; and, (ii) a potential long term revenue loss associated with the loss of some proportion of customers that were interrupted.

On page 92 of the Application in FEU's 2012-2013 RRA proceeding FEI states:

> The RSAM [Revenue Stabilization Adjustment Mechanism] stabilizes delivery margin received from Residential and Commercial customer classes on a UPC basis. If customer use rates vary from the <u>forecast levels used to set the rates, whether due to weather variances or other causes</u>, Mainland records the delivery charge differences in the RSAM deferral account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years. [Emphasis added]

17.1 Given that the RSAM recovers the difference between forecast and actual use per customer for residential and commercial customers does FEI incur revenue losses from the outage event? Please explain why, or why not.

<u>Response:</u>

The RSAM captures the difference between the forecasted and actual use rates multiplied by the <u>actual</u> customers. Assuming there is no actual loss of customers as a result of a widespread outage, the RSAM will serve to mitigate current revenue losses for residential and commercial customers from an outage event. However, the RSAM does not mitigate the losses from any demand losses from transportation customers, although, for the term of the 2014-2019 PBR pursuant to Commission Order G-138-14, any lost revenues from transportation customers would be captured by the flow-through mechanism approved.

In regards to the potential long-term revenue loss associated with the loss of some proportion of customers that were interrupted, this would not be mitigated by the RSAM or flow-through accounts. Considering the RSAM uses actual customers as part of the calculation, it is not captured in this calculation since the customers are no longer on the system. Further, the flow-through account serves to true-up the differences between many of the actual and forecasted amounts but, to the extent that the forecasted revenue requirement excluded those customers, they would not be captured in this true-up.

17.1.1 Please recalculate Tables ES-2a, ES-2b, 3.1, 3.2 and Figure ES-1 assuming that FEI does not experience revenue losses from residential and commercial customers due to an outage event.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

The scope of the study, as described in Appendix A-5 page 1, is to provide an estimate of total economic consequences. The purpose of the indicated tables is to show the total economic consequences of any outage event; the distribution of the consequences is incidental to the calculation and does not influence the total consequences. The tables thus show the incidence of these consequences as a first approximation before any redistribution effects might occur through, for example, insurance mechanisms or rate relief associated with cost of service tariff mechanisms or other mechanisms (such as the RSAM if it is applicable). In effect, any immediate losses experienced by the company that are subsequently recovered through rate relief or rate adjustments will simply see those economic consequences transferred back to customers. As noted in the response to BCUC IR 2.17.2, one potential second (or higher) round effect is that the higher tariffs will lead to some loss of customers. The total economic consequences in the tables and figure indicated thus do not change as a first approximation.

If the tables and figure were to be adjusted to show all the rounds of impacts, then this would result initially in an additional consumer impact that is exactly equal to the loss that was no longer borne by FEI. In addition, the consumer impact would be slightly greater for second and higher round impacts associated with rate adjustment or revenue stabilization mechanisms. Assessing this impact would require estimating long- and short-term demand elasticities by customer class; it might reasonably be expected that these demand response functions would change after a large outage event and estimation of such elasticities would thus be speculative. The expectation would, however, be that there would be some additional incremental non-zero losses; at this stage the experience with large outages - because of the rarity of such events - is inadequate to provide specific quantitative estimates that could be provided in tabular form. The tables and figures therefore serve their intended purpose of providing a total consequence estimate and first order approximation of incidence; the total consequences may however be a slight understatement for the reasons provided above.

To illustrate this, updates to the indicated tables and figures have been prepared to show the shift in incidence and are provided below along with additional notes to assist in interpretation. These supplementary graphics are numbered as follows to correspond to the originals in Appendix 5: Table ES-2a-supp, Table ES-2b-supp, Figure ES-1-supp, Table 3.1-supp, Table 3.2-supp.

Table ES-2a-supp.* Reference Case "As Is" economic consequences (millions $; 2014$) showing distribution of customer impact if net revenue losses to FEI are nil due to availability of cost recovery mechanisms.

Vulnerable Segment	Direct Fixed Expenditures				Relight	Impacts on Customers			Total	Customers
	Regulatory Response	Public Opinion	Government Relations	Loyalty		Cost Recovery Losses: Event	Cost Recovery Losses: Long term	Direct Disruption		
Nichol to Roebuck	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 29.14	$ 27.95	>$ 246.64	$ 256.35	>$ 564.83	252,300
Roebuck to Delta	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 29.14	$ 27.95	>$ 246.64	$ 256.35	>$ 564.83	252,300
Delta to Tilbury	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 26.74	$ 22.99	>$ 208.31	$ 214.65	>$ 477.44	229,690
Tilbury to Fraser	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 25.21	$ 19.98	>$ 183.21	$ 190.11	>$ 423.25	215,200
IP Segment 1	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 20.56	$ 14.88	>$ 138.45	$ 141.78	>$ 320.42	171,000
IP Segment 2	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 12.72	$ 6.96	>$ 45.47	$ 62.88	>$ 132.77	98,200
IP Segment 3	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 1.70	$ 0.58	>$ -	$ 5.74	>$ 8.50	14,100
IP Segment 6	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 1.54	$ 0.45	>$ -	$ 4.79	>$ 7.26	12,500
IP Segment 7	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 1.54	$ 0.45	>$ -	$ 4.79	>$ 7.26	12,500
IP Segment 10	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 0.59	$ 0.09	>$ -	$ 0.90	>$ 2.06	2,840
IP Segment 13	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 3.86	$ 1.24	>$ -	$ 12.47	>$ 18.05	29,620
Cape Horn to Coquitlam	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 19.57	$ 7.88	>$ 69.03	$ 80.71	>$ 181.95	163,280
Port Mann to Cape Horn	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 19.57	$ 7.88	>$ 69.03	$ 80.71	>$ 181.95	163,280
Nichol to Port Mann	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 20.55	$ 8.41	>$ 73.09	$ 85.84	>$ 192.63	172,572

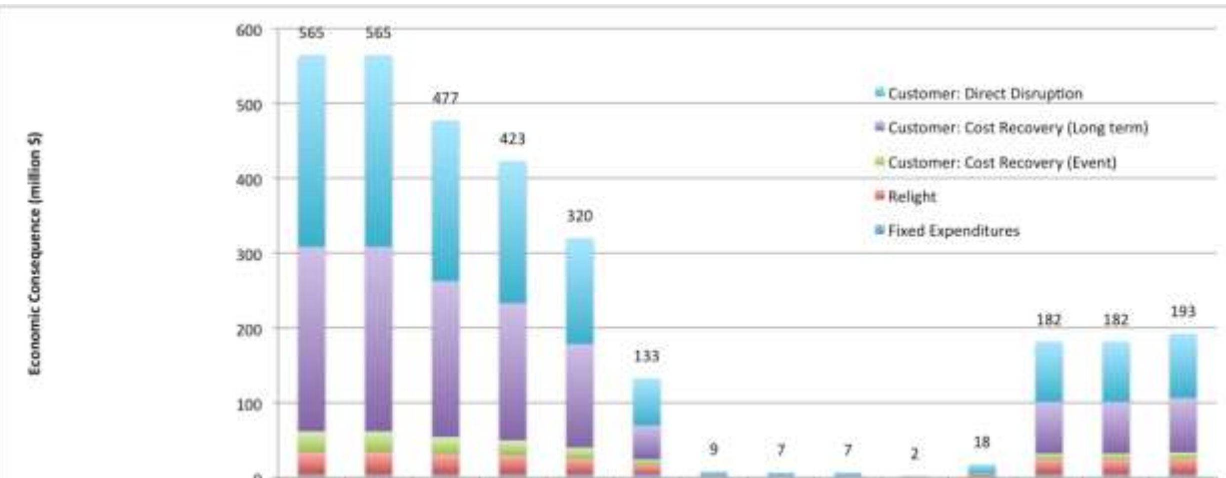
Table ES-2b-supp.* Reference Case "Residual" economic consequences (millions $; 2014$) showing distribution of customer impact if net revenue losses to FEI are nil due to availability of cost recovery mechanisms.

Vulnerable Segment	Direct Fixed Expenditures				Relight	Impacts on Customers			Total	Customers
	Regulatory Response	Public Opinion	Government Relations	Loyalty		Cost Recovery Losses: Event	Cost Recovery Losses: Long term	Direct Disruption		
Nichol to Roebuck	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 10.23	$ 5.79	>$ 42.06	$ 49.15	>$ 111.98	81,300
Roebuck to Delta	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 10.23	$ 5.79	>$ 42.06	$ 49.15	>$ 111.98	81,300
Delta to Tilbury	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 7.90	$ 3.52	>$ 13.39	$ 31.02	>$ 60.59	58,690
Tilbury to Fraser	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 6.41	$ 2.27	>$ -	$ 21.44	>$ 34.87	44,200
IP Segment 1	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 2	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 3	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 6	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 7	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 10	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 0.59	$ 0.09	>$ -	$ 0.90	>$ 2.06	2,840
IP Segment 13	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
Cape Horn to Coquitlam	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 15.20	$ 4.72	>$ 32.34	$ 49.27	>$ 106.27	121,880
Port Mann to Cape Horn	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 15.20	$ 4.72	>$ 32.34	$ 49.27	>$ 106.27	121,880
Nichol to Port Mann	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 18.04	$ 5.57	>$ 42.70	$ 57.84	>$ 128.91	131,172

The residual outages shown here correspond to the impacts after the IP System upgrades are undertaken; inspection shows that up to 171,000 customers are protected from a failure in the Nichol to Fraser segments and 41,400 customers are protected from a failure in the Nichol to Coquitlam segments. In the event of a failure in the Nichol to Port Mann segment, this corresponds to a net reduction in total consequences of approximately $64 million associated with these 41,400 customers.

* These supplementary (supp) tables vary little from the originals but most of the incidence of impacts is now borne entirely by customers if the company has mechanisms available to recover near- and long-term revenue losses that would otherwise accrue due to loss of customers. Also, some of the longer term impacts due to rate increases from cost recovery mechanisms represent a minimum (floor) value; these are represented in this version by the addition of a greater than (">") sign. These incremental amounts result from potential customer losses due to price-elasticity effects from the first round of impacts. The incremental impacts would be positive but they are in effect neglected here due to the difficulty in providing quantitative estimates: their estimation depends on speculating on the second round consequences of an avoided event which itself is a rare occurrence with which the industry has little experience. There is no reliable basis for estimating a demand function for such an event, although it can be reasonably assumed that the price elasticity of demand is negative such that the higher tariffs lead to further customer losses; hence it is appropriate to indicate that the impacts for some of these (including total consequences) are now potentially higher than the originals.

Figure ES-1-supp.* Aggregate "As Is" economic consequences of outage without LMSU Projects showing distribution of consequences if net revenue losses to FEI are nil due to availability of cost recovery mechanisms. IP Segments 4, 5, 8, 9, 11 and 12 can be isolated and would not be subjected to any disruptions in service either before ("As Is") or after ("Residual") any of the upgrade Projects are undertaken; consequences for these segments are thus nil.



	Nichol to Roebuck	Roebuck to Delta	Delta to Tilbury	Tilbury to Fraser	IP Segment 1	IP Segment 2	IP Segment 3	IP Segment 6	IP Segment 7	IP Segment 10	IP Segment 13	Cape Horn to Coquitlam	Port Mann to Cape Horn	Nichol to Port Mann
Customer: Direct Disruption	256	256	215	190	142	63	6	5	5	1	12	81	81	86
Customer: Cost Recovery (Long term)	247	247	208	183	138	45	0	0	0	0	0	69	69	73
Customer: Cost Recovery (Event)	28	28	23	20	15	7	1	0	0	0	1	8	8	8
Relight	29	29	27	25	21	13	2	2	2	1	4	20	20	21
Fixed Expenditures	5	5	5	5	5	5	0	0	0	0	0	5	5	5
Total	565	565	477	423	320	133	9	7	7	2	18	182	182	193

Vulnerable Segment

* This supplementary (supp) figure varies little from the originals but most of the incidence of impacts is now borne entirely by customers if the Company has mechanisms available to recover near- and long-term revenue losses that would otherwise accrue due to loss of customers. The column totals should be regarded as conservative

estimates (i.e., lower bound) in comparison to those in the original Figure ES-1; the reader is directed to the notes accompanying Table ES-2a-supp for further explanation.

Table 3.1-supp.* Reference Case Results – "As Is" Consequences ($ million) showing distribution of customer impact if net revenue losses to FEI are nil due to availability of cost recovery mechanisms.

Vulnerable Segment	Direct Fixed Expenditures				Relight	Impacts on Customers			Total	Customers
	Regulatory Response	Public Opinion	Government Relations	Loyalty		Cost Recovery Losses Event	Cost Recovery Losses Long term	Direct Disruption		
Nichol to Roebuck	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 29.14	$ 27.95	>$ 246.64	$ 256.35	>$ 564.83	252,300
Roebuck to Delta	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 29.14	$ 27.95	>$ 246.64	$ 256.35	>$ 564.83	252,300
Delta to Tilbury	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 26.74	$ 22.99	>$ 208.31	$ 214.65	>$ 477.44	229,690
Tilbury to Fraser	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 25.21	$ 19.98	>$ 183.21	$ 190.11	>$ 423.25	215,200
IP Segment 1	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 20.56	$ 14.88	>$ 138.45	$ 141.78	>$ 320.42	171,000
IP Segment 2	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 12.72	$ 6.96	>$ 45.47	$ 62.88	>$ 132.77	98,200
IP Segment 3	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 1.70	$ 0.58	>$ -	$ 5.74	>$ 8.50	14,100
IP Segment 6	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 1.54	$ 0.45	>$ -	$ 4.79	>$ 7.26	12,500
IP Segment 7	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 1.54	$ 0.45	>$ -	$ 4.79	>$ 7.26	12,500
IP Segment 10	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 0.59	$ 0.09	>$ -	$ 0.90	>$ 2.06	2,840
IP Segment 13	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 3.86	$ 1.24	>$ -	$ 12.47	>$ 18.05	29,620
Cape Horn to Coquitlam	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 19.57	$ 7.88	>$ 69.03	$ 80.71	>$ 181.95	163,280
Port Mann to Cape Horn	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 19.57	$ 7.88	>$ 69.03	$ 80.71	>$ 181.95	163,280
Nichol to Port Mann	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 20.55	$ 8.41	>$ 73.09	$ 85.84	>$ 192.63	172,572

Table 3.2-supp.* Reference Case Results – "Residual" Consequences ($ million) showing distribution of customer impact if net revenue losses to FEI are nil due to availability of cost recovery mechanisms.

Vulnerable Segment	Direct Fixed Expenditures				Relight	Impacts on Customers			Total	Customers
	Regulatory Response	Public Opinion	Government Relations	Loyalty		Cost Recovery Losses Event	Cost Recovery Losses Long term	Direct Disruption		
Nichol to Roebuck	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 10.23	$ 5.79	>$ 42.06	$ 49.15	>$ 111.98	81,300
Roebuck to Delta	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 10.23	$ 5.79	>$ 42.06	$ 49.15	>$ 111.98	81,300
Delta to Tilbury	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 7.90	$ 3.52	>$ 13.39	$ 31.02	>$ 60.59	58,690
Tilbury to Fraser	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 6.41	$ 2.27	>$ -	$ 21.44	>$ 34.87	44,200
IP Segment 1	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 2	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 3	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 6	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 7	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
IP Segment 10	$ 0.03	$ 0.20	$ 0.05	$ 0.20	$ 0.59	$ 0.09	>$ -	$ 0.90	>$ 2.06	2,840
IP Segment 13	$ -	$ -	$ -	$ -	$ -	$ -	>$ -	$ -	>$ -	-
Cape Horn to Coquitlam	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 15.20	$ 4.72	>$ 32.34	$ 49.27	>$ 106.27	121,880
Port Mann to Cape Horn	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 15.20	$ 4.72	>$ 32.34	$ 49.27	>$ 106.27	121,880
Nichol to Port Mann	$ 0.25	$ 2.00	$ 0.50	$ 2.00	$ 18.04	$ 5.57	>$ 42.70	$ 57.84	>$ 128.91	131,172

* The tables reflect that IP Segments 4, 5, 8, 9, 11 and 12 can be isolated and would not be subjected to any disruptions in service either before ("As Is") or after ("Residual") any of the upgrade Projects are undertaken; consequences are therefore nil.

These supplementary (supp) tables vary little from the originals but most of the incidence of impacts is now borne entirely by customers if the company has mechanisms available to recover near- and long-term revenue losses that would otherwise accrue due to loss of customers. Also, some of the longer term impacts due to rate increases from cost recovery mechanisms represent a minimum (floor) value; these are represented in this version by the addition of a greater than (">") sign. These incremental amounts result from potential customer losses due to price-elasticity effects from the first round of impacts. The incremental impacts would be positive but they are in effect neglected here due to the difficulty in providing quantitative estimates: their estimation depends on speculating on the second round consequences of an avoided event which itself is a rare occurrence with which the industry has little experience. There is no reliable basis for estimating a demand function for such an event, although it can be reasonably assumed that the price elasticity of demand is negative such that the higher tariffs lead to further customer losses; hence it is appropriate to indicate that the impacts for some of these (including total consequences) are now potentially higher than the originals.

17.2 Given that FEI's revenues are established using a cost of service methodology, please explain why a reduction in sales volumes due to "the loss of some proportion of customers that were interrupted" would have an impact on FEI's revenues longer term?

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

The cost of service rates are a proxy for societal costs borne by the Company and remain static before and after the event as a first approximation. The scope of the study, as described Appendix A-5 page 1, is to provide an estimate of total economic consequences. If (as a second approximation) any such first round revenue losses were to be recovered through rate adjustments, then the equivalent impact of this revenue loss would be borne by consumers through higher tariffs: there would be no change to the overall total economic consequences. It should be noted that the higher tariffs would, through an elasticity effect, potentially further reduce demand and result in some incremental losses to revenues that would again require an additional smaller higher order increase in tariffs. These higher order losses are ignored in the consequence analysis as they are regarded as small relative to the overall impact. It suggests, however, that the presence of a cost recovery mechanism would result in marginally higher total economic consequences than that considered.

FEI further adds that although revenue may be recovered over the short term; loss of load and customers would result in rate pressure and ultimately, FEI's ability to attract and retain customers may be diminished and accordingly revenue over the long term may be affected.

17.2.1 Please recalculate Tables ES-2a, ES-2b, 3.1, 3.2 and Figure ES-1 assuming that FEI does not experience "long term" revenue losses due to an outage event.

Response:

H.J. Ruitenbeek Resource Consulting Ltd. provides the following response:

As described in the responses to BCUC IR 2.17.1.1 and IR 2.17.2, the removal of the revenue losses from FEI simply shifts the burden to the customer: the total consequences in the tables and figure indicated thus do not change as a first approximation. The tables and figures serve their intended purpose of providing a total consequence estimate and first order approximation of incidence; the total consequences currently presented in the tables and figure may however be a slight understatement. Recalculation of the tables would involve estimating the amount of this relatively small additional impact and would be a speculative exercise; the experience with large outages - because of the rarity of such events - is inadequate to provide specific quantitative estimates that could be provided in tabular form.

Updates to the indicated tables and figures have, however, been prepared to show the shift in incidence and are included in the response to BCUC IR 2.17.1.1 along with additional notes to assist in interpretation. These supplementary tables and graphic are numbered as follows to correspond to the originals in Appendix 5: Table ES-2a-supp, Table ES-2b-supp, Figure ES-1-supp, Table 3.1-supp, Table 3.2-supp.

8.0 Reference: COQUITLAM GATE IP

Exhibit B-4, BCUC 1 12.3, 12.3.1

Project description

In response to BCUC IR 1.12.3 FEI state that "building permits have not yet been acquired."

18.1 What, if any, difficulties may FEI foresee in obtaining such building permits?

Response:

As outlined in the response to BCUC IR 1.12.3, the building permit applications will require detailed engineering input and will therefore be prepared and submitted during the detailed design stage after receipt of CPCN approval. The permitting process will be complex and may encounter difficulties due to the urban nature of the Project locations. However, the proposed buildings are a necessary Project component of the Coquitlam Gate and East 2nd & Woodland stations; they will replace existing buildings on these station sites that enclose above ground mechanical and electrical equipment for safety, operation and aesthetic reasons.

The respective municipalities that will have responsibility for reviewing and approving the Project building permit applications have already been informed of the planned development at the Coquitlam Gate station and East 2nd & Woodland stations. FEI will continue ongoing consultation, throughout the Project lifecycle, to update major stakeholders as to Project development and record and respond to feedback and information requests. This approach will help to mitigate potential risk and difficulties with the building permit application and approvals process. FEI's Project Execution Plan will specifically address Project permit application requirements, including building permits, to ensure successful permit process outcomes, by:

- Provision of sufficient time in the Project schedule to develop full and comprehensive permit applications;
- Early completion of the detailed engineering necessary to inform the building permit application to allow early submission of all necessary permit applications; and
- Schedule contingency which will mitigate potential project delays during the permitting process.

FEI has identified potential delays in municipal permits (including building permits) as a Project risk in Appendix A-21 of the Application. Appendix A-21 identifies existing controls already in place and a risk treatment plan to mitigate the risk of delays. In the event of a delay, FEI will manage the schedule impact to the extent possible using schedule contingency (float). In the unlikely event that a building permit would not be granted based on a particular application request by FEI, FEI will work with the respective municipality and modify the proposed building design such that all permit requirements including municipality and stakeholder concerns are addressed and thereby assuring that the necessary permit(s) can then be granted.

18.2 In the event FEI are not granted permits for station buildings what alternative options have FEI considered and what are the associated cost implications?

Response:

Please refer to the response to BCUC IR 2.18.1.

F. PROJECT NEED AND JUSTIFICATION - FRASER GATE

19.0 Reference: PROJECT NEED JUSTIFICATION

Exhibit B-4, BCUC 1.3.1., 1.3.3.1

Operational flexibility

In response to BCUC IR 1.3.1 FEI state: "FEI is unable to confirm if the Coquitlam gate IP pipeline was ever able to supply the system year round without support from Fraser gate."

In response to BCUC IR 1.3.3.1 FEI provided a table showing the estimated outage windows for Metro IP from 1994-2014. The table indicates there were no scheduled outage periods for Fraser gate pipeline maintenance between 2003-2014.

19.1 Please confirm, otherwise explain, that maintenance which required an outage was carried out on the Fraser Gate pipeline between 2003-2014.

Response:

Not confirmed. FEI has performed no work on the Fraser Gate IP pipeline between 2003 and 2014 that has required the pipeline to be taken out of service or required bypasses to be installed. Refer also to the response to CEC IR 1.21.2.1.

19.1.1 If confirmed, please described that work, provide the costs and compare to the work and costs assuming the proposed Coquitlam Gate IP pipeline was installed.

Response:

Please refer to the response to BCUC IR 2.19.1.

19.2 Please confirm, otherwise explain, that maintenance which normally requires an outage was carried out on the Fraser Gate pipeline between 2003-2014, but without an outage.

Response:

Not confirmed. Please refer to the response to BCUC IR 2.19.1.

19.2.1 If confirmed, please described that work, provide the costs and compare to the work and costs assuming the proposed Coquitlam Gate IP pipeline was installed.

Response:

Please refer to the response to BCUC IR 2.19.2.

G. PROJECT ALTERNATIVES – FRASER GATE

20.0 Reference: ALTERNATIVES DESCRIPTION AND ALTERNATIVES EVALUATIONS

Exhibit B-1-6, p. 19; Exhibit B-4, BCUC 1.33.1.1.2, 1.33.1.2, 1.33.1.3

Alternatives to project as proposed

On page 19 of the Evidentiary Update FEI states that the revised scope of the Fraser Gate IP Project involves the replacement of approximately 280 metres of NPS 30 pipeline, and that this replacement length extends 80 metres into the competent soils zone.

In response to BCUC IR 1.33.1.1.2 FEI states that no significant movement is expected at the NPS 30 pipeline at the outlet of the Fraser Gate station if a 1:2475 seismic event occurs.

In response to BCUC IRs 1.33.2 and 1.33.3 FEI states reasons why it considers that an alternative involving ground improvement would offer no advantage over pipeline replacement.

20.1 Please discuss whether the reduction in length of pipe to be replaced makes it possible to complete the Fraser Gate pipeline replacement before the Coquitlam Gate IP Project is completed, without installing a bypass.

Response:

This response addresses BCUC IRs 2.20.1 and 2.20.1.1.

No, the reduction in length of pipe to be replaced does not make it possible to complete the Fraser Gate IP pipeline replacement before the Coquitlam Gate IP is completed without the use of bypasses. There is also no associated reduction in scope or cost of these bypasses, as further described below.

The optimum bypass configuration for the NPS 30 Fraser Gate IP pipe replacement comprises two short temporary bypasses, one at each end of the section of NPS 30 pipe to be replaced, instead of a single long continuous bypass the same length as the section of pipeline to be replaced. This proposed configuration avoids the constraints associated with constructing and operating a long temporary bypass along East Kent Avenue South while also constructing the replacement NPS 30 pipeline and maintaining access to the business at the end of East Kent Avenue South. After installation of each of the shorter bypasses, a short section of the existing NPS 30 pipeline (a few metres) would be removed at each bypass location at either end of the vulnerable section of NPS 30 pipeline, to facilitate tie-in of the new replacement NPS 30 pipeline. During completion of the tie-in procedure, the gas would flow through each of the shorter bypasses and the section of NPS 30 pipeline to be replaced. After completion of the tie-in procedures, each bypass would be removed, the existing NPS 30 pipeline remaining between the tie-in locations would be abandoned in place, and the gas would then flow through the new section of NPS 30 pipeline.

As described in the response to BCUC IR 1.3.6, the estimated indicative cost for the proposed temporary bypass during construction of the Fraser Gate IP Project is approximately $1.4 million.

The proposed Coquitlam Gate IP Project will provide full system resiliency; as such, the Fraser Gate IP Project could be constructed after the competition of the Coquitlam Gate IP Project without the use of bypasses (i.e. the pipeline could be shut-in with no associated customer outages).

20.1.1 If a bypass is still required what are the revised expected bypass costs and how do these costs compare to the outage costs assuming a new Coquitlam Gate IP pipeline.

Response:

Please refer to the response to BCUC IR 2.20.1.

20.2 Considering that the length of pipeline that is in soil that is subject to liquefaction is approximately 200 metres, please discuss the pros and cons of improving the seismic withstand ability of this section of the pipeline by ground improvement, compared to the proposed replacement of the pipeline.

Response:

FEI has determined that pipe replacement is the preferred alternative to mitigate the identified seismic vulnerability on the existing NPS 30 Fraser Gate IP pipeline. The information submitted in the Evidentiary Update (Exhibit B-1-6) did not result in a change to this determination.

FEI is not aware of any pros associated with improving the seismic withstand ability of this section of pipeline by ground improvement. There are significant cons associated with a potential ground improvement alternative, compared to the proposed replacement of the pipeline, which are summarized as follows (identified in consultation with Golder Associates):

- higher environmental impact compared to pipe replacement;
- more complex project planning and execution risk (e.g. construction permitting, in-stream works etc.);
- significantly larger scope and longer on-site construction timeframe, resulting in prolonged disruption to businesses and residents of the community; and
- Higher overall construction cost as per the high level cost comparison of the ground improvement option and the proposed pipeline replacement option presented in the response to BCUC IR 2.20.4.

FEI considers that environmental impacts and risks are increased based on information from Golder Associates Inc. (Golder) indicating that ground disturbance extending into the Fraser River should be expected. Golder also advised that ground improvement would require that existing rip rap protecting the Fraser River bank would need to be removed temporarily. As there is no temporary storage available on site for the rip rap material, the material may need to be shipped off-site using a barge. Golder estimates that five barge loads (3,000 m^3) of rip rap material may need to be removed, which would require in-stream work.

Project planning and execution, including construction permitting, for a ground improvement option would be significantly more complex than the preferred alternative based on the larger scope and construction footprint, combined on-land and in-stream work and greater environmental and public impacts (e.g. in-stream work, parkland closure for an extended period, higher noise levels as compared to pipe replacement, potential increased impact to local business due to equipment such as vibro rigs and barges impacting a larger area).

Golder also identified that it may be challenging to meet potential noise limits imposed by local by-laws and/or permits and that a ground improvement alternative would likely result in a longer on-site construction timeframe and-related disruption.

20.3 Please explain why the utility believes it is necessary to excavate, inspect and potentially repair the existing NPS 30 pipeline before undertaking ground improvement.

Response:

Reasons for exposing and assessing the integrity of the existing NPS 30 pipeline before or during ground improvement are:

- To confirm that the existing NPS 30 pipeline is capable of withstanding any potential impacts from the ground improvement construction;
- To mitigate the risk of potential differential settlement or other ground displacement that might occur as a result of the ground improvement; and
- To improve confidence of long-term asset performance after ground improvement involving a significant capital expenditure.

If, as a result of the assessment, it is found that the existing pipe would require upgrade to meet these requirements, then the upgrades would be completed prior to execution of the ground improvement scope.

20.4 Based on the optimized scope of the Fraser Gate Project as filed in the Evidentiary Update, please provide a cost estimate for using ground improvement to deal with seismic concerns.

Response:

Considering the revised scope of work submitted by FEI in its Evidentiary Update (Exhibit B-1-6), Golder Associates provided a revision to their estimate provided in the response to BCUC IR 1.33.1.3.

Based on Golder's past experience of similar seismic remediation projects involving installation of stone columns using the vibro-replacement method and vendor input, an indicative direct construction cost for ground improvement work could be in the order of $4 million to $7 million. This indicative cost may be compared to the AACE Class 3 direct construction costs of $3.5 million estimated for the proposed NPS 30 pipeline replacement alternative. The direct cost for the ground improvement work excludes owner's costs, engineering and other costs such as project risk contingency, AFUDC and the cost to excavate, examine and upgrade, if necessary, the existing section of the Fraser Gate IP pipeline in the seismically vulnerable area. These incremental costs could result in a total indicative cost estimate of this option in the range of $10 million to $15 million.

Further ground improvement project scope definition would be required in order to facilitate a more direct comparison to the proposed pipe replacement AACE Class 3 estimate and project impacts. Given the complexity associated with a potential ground improvement option, it is anticipated that approximately two months of engineering analysis would be required to establish an improved estimate beyond the range for direct construction costs provided herein. Further environmental studies over a similar timeframe would also be required to improve the estimate of owner's costs.

20.5 If ground improvement were used to deal with the seismic concern for the Fraser Gate pipeline, could this work be carried out prior to completion of the Coquitlam Gate IP Project and without installing a bypass?

Response:

A potential ground improvement option would be external to the pipeline; assuming no pipeline condition issues were identified prior to or during construction, it would not be expected to require a bypass and could be completed independent of the Coquitlam Gate IP Project.

However, given the expected increased risk and complexity associated with such a ground improvement option and the potential consequences of an associated forced outage, FEI does not believe this work should be carried out prior to completion of the Coquitlam Gate IP Project.

Please also refer to the response to BCUC IR 2.20.5.1.

20.5.1 What is the earliest reasonable date for completion of the ground improvement?

Response:

Based on the limited degree of project definition for a potential ground improvement option and the complexities with regard to working in and around water and around residential buildings, FEI does not believe that an earlier date than the current proposed pipe replacement schedule could be achieved. As for the cost estimate (see the response to BCUC IR 2.20.4) of a potential ground improvement project, significant time would be required to develop a project schedule, including a reasonable completion date.

20.6 The response to BCUC IR 1.33.1.1.1 FEI states that the cost of further modifications at Fraser Gate station will be managed within the sustainment capital budget; please discuss whether the cost of dealing with the seismic concern for the Fraser Gate pipeline by ground improvement could be managed within the sustainment capital budget.

Response:

The cost of dealing with the seismic concern for the NPS 30 Fraser Gate IP pipeline by either pipe replacement or by a potential ground improvement option is estimated at above the FEI CPCN threshold, and as such does not fall within sustainment capital.

H. ACCOUNTING – FRASER GATE

21.0 Reference: PROJECT COSTS AND ACCOUNTING TREATMENT

Exhibit B-1-6, Section 4.1, p. 25; FEI 2014-2019 PBR Plan – Annual Review for 2015 Rates (FEI 2015 Annual Review), Exhibit B-1, p. 15

Bill impact

On page 25 of the Evidentiary Update FEI states:

> The impact to customer rates in 2019 (when the asset enters rate base) is approximately \$0.124 per GJ and levelized over the 60 year analysis period is approximately \$0.104 per GJ. For a typical FEI residential customer consuming an average 95 GJ per year, in 2019, this would equate to approximately \$11.80 per year. The annual impact to customers from the Coquitlam Gate IP Project in 2019 would be approximately \$11.40 per year and from the Fraser Gate IP Project would be approximately \$0.40 per year.

On page 15 of the Application in the FEI 2015 Annual Review proceeding, it shows an average residential use per customer of 81.5 GJ/ year in 2015.

21.1 Please provide the source of the "typical FEI residential customer consuming an average 95 GJ per year, in 2019."

Response:

The FEI gas cost quarterly filings submitted to the BCUC for the bill impact analysis from 2008 through to 2014, as well as previous revenue requirement and CPCN applications, had used 95 GJ per year representing a typical use rate for a residential customer in the Lower Mainland Service Area. Starting in January 2015 (i.e. after FEI filed this CPCN with the Commission in December 2014) FEI decreased the typical use rate of a residential customer to 90 GJ per year reflecting the average use of Mainland Service Area customers for bill impact calculations after amalgamation.[12]

The 81.5 GJ/year referenced in the question preamble was the weighted average forecast annual use for 2015 for all FEI Residential customers (with the exception of the Fort Nelson Service Area) in the service areas of Mainland, Vancouver Island and Whistler.

[12] The change to 90 GJs per year is reflective of the former Inland and Columbia Service Areas now being included with the former Lower Mainland Service Area in the calculation of the impact on the new Mainland Service Area customers (which following amalgamation is now reflective of customers in Inland, Columbia and the Lower Mainland).

Historically, FEI has not amended annual bill calculations each year to reflect the average forecast use for the upcoming year. For comparability with previous years, the average use has been held constant until there is a significant change in use or, as in the most recent case, where the amalgamation of the utilities resulted in a change.

21.2 Please calculate the 2019 annual impact to customers from the Coquitlam Gate IP Project and the Fraser Gate IP Project based on an average residential use per customer of 81.5 GJ/ year in 2015. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

The 2019 annual impact to customers from the Coquitlam Gate IP Project and the Fraser Gate IP Project based on an average residential use per customer of 81.5 GJ is $10.11 per year or 1.1% on Burner Tip as shown in the following table. The Average Rate Impact ($ / GJ) is from the Evidentiary Update filing Table 4-2, Page 26. (Please note that footnote 1 precedes Table 4-2 on Page 26 of the Evidentiary Update).

2019 Average Rate Impact / GJ	Annual Consumption GJ	Annual Bill Impact	Jan. 1, 2015 Burner Tip [3)]	Impact on Burner Tip
$ 0.124	81.5	$ 10.11	$ 921.66	1.1% [2)]

2) $10.11 / $921.66 = 1.1%

[3)] Original Interim Tariff Pages Effective January 1, 2015 to Reflect Amalgamation; BCUC Orders G-21-14, G-175-14, G-176-14, G-177-14, G-178-14; Tab 5, Page 1, Line 19, Column “Effective January 1, 2015 Rates – Annual $, filed December 8, 2014.

Please refer to Attachment 21.2 for the fully functioning electronic spreadsheet.

22.0 Reference: PROJECT COSTS AND ACCOUNTING TREATMENT

FEI 2014-2019 PBR Decision, p. 181

PBR impact

On page 181 of the FEI 2014-2019 PBR Decision states: Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.

22.1 If the Fraser Gate IP project is made a standalone CPCN project and falls below the current CPCN exemption threshold of $5 million, please explain how the Fraser Gate IP project would be treated in the PBR.

Response:

As stated in the response to BCUC IR 2.20.6, the cost of dealing with the seismic concern for the NPS 30 Fraser Gate IP pipeline by either pipe replacement or by a potential ground improvement option is greater than the FEI CPCN threshold that was approved for 2014 and 2015 pursuant to Order G-138-14.

In the extremely unlikely event the Fraser Gate IP Project was reforecast to be below the $5 million threshold and the CPCN application was withdrawn, the capital and O&M expenditures for this project would be managed within the formula amounts as set out under the PBR plan.

22.1.1 Please explain how variances of +/- $100,000 between the forecast and actual cost would be reflected in the PBR earnings sharing mechanism.

Response:

As discussed in the response to CEC IR 2.22.1, the Fraser Gate IP Project meets the CPCN threshold requirement of $5 million and it is extremely unlikely for the forecast capital costs to fall below this threshold. Therefore, a scenario where a cost variance for this project would be subject to earnings sharing is equally unlikely.

Notwithstanding this, the following describes how variances in actual capital costs from the formula-based capital are included in the ESM:

- The cumulative variance in capital spending from the forecast under PBR formula is calculated;

- The cumulative variance is multiplied by the equity percentage of the capital structure and the return on equity;
- The calculation is divided by one minus the current income tax rate to arrive at a before tax figure;
- The before tax amount is divided by two reflecting the symmetrical sharing between customers and the Company.

If the cumulative variance is a negative number, it means that actual capital spending is less than PBR formula and customers would receive a reduction or decrease in their rates. Conversely, if the cumulative variance is a positive number it means that actual capital spending is greater than PBR formula and customers would see an increase in their rates.

The formula for calculating the impact on the Earnings Sharing Mechanism for cumulative capital variance is as follows, and provides a demonstration on the impact of a variance of $100,000 using the currently approved return on equity and equity component of the capital structure:

ESM customer impact = Capital Cost Variance x Equity Capitalization % x Return on Equity / (1 – current Tax rate) / 2.

E.g. $100,000 x 38.5% x 8.75% / (1 – 26%) / 2 = $2,276 returned to or collected from customers.

22.2 Please discuss how the Coquitlam Gate IP pipeline replacement project affects sustainment capital.

Response:

Since sustainment capital under the PBR plan is determined by a formula, the Coquitlam Gate IP pipeline replacement project will not impact sustainment capital during the PBR term.

Further, the Coquitlam Gate IP Project is not expected to result in sustainment capital expenditures during the PBR term. As shown in Confidential Appendix E-1-1 (Schedule 6, Line 6), FEI has forecast sustainment capital expenditures associated with this Project of approximately $1 thousand per year to commence in 2020.

22.3 Please confirm, otherwise explain, that there are lateral replacements, IP/IP pressure regulating vault station replacements and other equipment replacements, such as replacement of components in the East 2nd and Woodland and Coquitlam stations, that are being replaced as part of this project that are included in the sustainment capital base.

Response:

The Coquitlam Gate IP Project includes replacement of assets that are currently included in rate base. As the proposed Project consists of a pipeline operating at a higher pressure than the existing pipeline, a combination of lateral replacements, installation of additional IP/IP pressure regulating vaults and equipment replacements would be used to connect the new pipeline to existing laterals and stations that currently only have the ability to operate at the lower pressure. This work will be part of the Project.

FEI is unclear what is meant by the term “sustainment capital base”. For capital planning purposes and a forecast of annual expenditures, capital is segregated by growth, sustainment and other categories. However, during the term of the PBR the annual capital expenditures are determined by the approved PBR formula. The base for this formula includes 2013 sustainment expenditures of approximately $71 million and did not include expenditures related to any of the assets that are affected by the Coquitlam Gate IP Project. If the question is seeking to determine if there is double counting as between Project capital and the formulaic capital, FEI confirms there is not.

I. PUBLIC AND FIRST NATIONS CONSULTATION

23.0 Reference: PUBLIC CONSULTATION

Exhibit B-4, BCUC 1.58.1

Legacy projects

In response to BCUC IR 1.58.1 FEI explains: “FEI has continuing meetings with each of the municipalities on legacy projects that would benefit the communities and align with municipal priorities.”

23.1 Please provide a list of legacy projects being considered, provide their cost estimates and justify why FEI ratepayers should pay for these projects.

Response:

FEI views legacy projects as a mitigation initiative to offset negative impacts (short or long term) the project has created on stakeholders. To date, the Company has had discussions with the City of Burnaby in this regard. FEI has identified potential stakeholder impacts due to pipeline construction activities along the Burnaby Mountain Urban Trail. This trail is within the road allowance along Broadway Avenue and is closed to vehicular traffic. While specific plans and costs have yet to be developed, FEI believes that, in addition to restoration work, a modest budget for trail enhancements will improve recreational facilities and access while also improving operational access for leak surveys and will allow FEI to better manage vegetation in proximity to the pipeline to be located within this road allowance.

Preliminary discussions with municipal officials in Vancouver and Coquitlam have not yet identified specific areas that will provide similar benefits to those described for Burnaby.

These types of legacy projects also assist with garnering stakeholder and municipal support for projects, which typically results in efficiencies (such as improved permitting timelines, etc.) by reducing construction delays and hence reducing overall project costs. Since all customers benefit from these project efficiencies, FEI considers these projects and the associated cost to be an appropriate Project expenditure. The budget for these activities in all three cities for both the Coquitlam Gate IP Project and the Fraser Gate IP Project totals $300 thousand.

24.0 Reference: PUBLIC CONSULTATION

Exhibit B-1-6, Section 6.2, p. 38

Adequacy of public consultation

On page 38 of the Evidentiary Update FEI states:

> FEI will continue to consult with stakeholders regarding route issues, the schedule for the Projects, plans to mitigate traffic disruption, and public safety. Another series of public information sessions is planned prior to start of construction, with the goal of informing residents and the public about construction activities, traffic issues and mitigation strategies.

24.1 How has FEI informed residents and businesses along the original route that the preferred route has changed?

Response:

Residents along the portion of the original route affected by this change and residents and businesses along the new preferred route were invited to a public information session, as follows:

1. An invitation was mailed to all residents and businesses within 500 metres on each side of the original route. This catchment area encompassed residents and businesses along the new preferred route of Lougheed Highway;
2. Two advertisements were placed in the two local newspapers;
3. A public invitation was included on the Project's webpage on the FEI website; and
4. An e-mail was sent to representatives of the Highlawn Drive residents group who had previously expressed concerns.

24.2 How will FEI inform commuters who use the Lougheed Corridor about planned construction and traffic and transit disruption?

Response:

In collaboration with its traffic consultant, FEI will prepare a detailed traffic management specification that will be included in the construction tender documents. As part of its bid submission, contractors will present a representative traffic management plan from a successfully executed project that is similar in nature. Upon award, the successful contractor will prepare site specific traffic management plans that will be reviewed and approved by FEI and will include specifics regarding communications for commuters, etc. FEI will work with the contractor to identify direct traffic and parking impacts and will outline mitigation measures during construction.

Once construction is underway, FEI will work with the contractor and will utilize a range of notification methods as well as several communication channels to ensure all those impacted by the construction are notified in a timely manner. These communications will include:

- Hand delivery of notices to homes and businesses along the route, several days in advance of construction;
- Emails to traffic reporters at radio and television stations, who will announce closures and disruptions hourly/daily;
- Sponsorship of traffic radio announcements;
- Updates to the project's webpage on FEI's website;
- Distribution of updated information to municipalities for inclusion on the their 'roads and traffic' webpages on a regular basis;
- Electronic signage along major traffic arteries;
- Advertisements in community newspapers;
- SMS – text messages sent to cellphones of commuters/residents who have signed up for updates; and
- Twitter – regularly scheduled tweets about ongoing/upcoming construction.

24.3 Has FEI received any feedback or concerns regarding the frequency of construction and/or traffic disruption on Lougheed Highway? If so, how has FEI incorporated this feedback into its public consultation plans?

Response:

Attendees at the April 21, 2015 public information session spoke to the frequency of construction projects along Lougheed Highway; they seemed to acknowledge and recognize that the route is an 'on-going construction zone' due to the location of existing and newly constructed utilities and transportation infrastructure (water mains, elevated transit) below and above the roadway. They also expressed concerns about traffic disruption during construction of the proposed Project. FEI's traffic consultant was in attendance to listen and consider how to incorporate this feedback into ongoing traffic management planning.

Individual businesses along the Lougheed realignment are being consulted one-on-one, and to date have expressed concerns about interruption and access which include:

- customer access;
- commercial goods access and egress;
- emergency responder requirements; and
- public services access (transit, garbage pick-up, etc.).

FEI is incorporating this feedback into its public consultation plans by communicating with businesses as follows:

- Cataloguing key business contacts, meeting with them and understanding their business requirements;
- Communicating project details including construction practices, methods, schedules and FEI contact information;
- Committing to development of a plan with the contractor, when hired, to minimize access interruption/inconvenience to their business;
- Monitoring business impacts during construction; and
- Maintaining contact throughout the Project.

Attachment 1.1

BC Oil & Gas COMMISSION

June 5, 2015

Mr. Bryan Balmer
Manager, System Integrity Programs
FortisBC

Dear Mr. Balmer,

With regard to the questions from the BC Utilities Commission (BCUC) that pertain to the BC Oil & Gas Commission (OGC) that you directed to us via email on May 22nd, 2015, our response to each question is below.

1.1 Please confirm and provide evidence, otherwise explain, that the Oil and Gas Commission (OGC) would not accept continuing ongoing integrity and leak management as a longer-term (i.e. 5-10 years) means to prevent or assist in containing or preventing the spillage.

1.1 OGC response:
The OGC would not accept leak survey, leak detection and repair as a means to prevent spillage. Increased leak survey frequency is expected to reduce the consequence associated with a spillage but not prevent future leaks.

Section 37(3) of the *Oil and Gas Activities Act* requires that: Permit holders aware that spillage is likely to occur must make reasonable efforts to prevent or assist in containing or preventing spillage.

To meet its regulatory obligations, the permit holder must demonstrate that the increased leak survey frequency (1 week) is sufficient to ensure that the pipeline can continue to remain in service and not present undue risk to the public or the environment until the replacement line is commissioned. From the OGC's perspective, it is not desirable to delay replacement until a pipeline is inoperable. The process of replacement takes time.

1.3 Please confirm, otherwise explain, that the OGC would consider FEI's rehabilitation an acceptable means to prevent or assist in containing or preventing the spillage.

1.3 OGC Response:
Assuming the rehabilitation work is to dig up and inspect EVERY weld, this option would be considered by the OGC. FortisBC Energy Inc. (FEI) would also have to demonstrate that the rest of the pipeline is fit for service and continue the increased frequency leak survey on uninspected sections of the pipeline, until all the welds have been inspected and repaired where necessary. This approach is based on no increased leak frequency or size of leak being detected.

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1.4 Please confirm, otherwise explain, that the OGC does not consider or review the cost of what FEI proposes as mitigation in response to the OGC order.

1.4 OGC Response:
The OGC issued the order to FEI in response to increased incidents being reported on the pipeline. In making the order, the OGC considered the protection of public safety and the environment. It is not part of the OGC's mandate to review the costs of recommendations proposed by the Engineering Assessment. The OGC reviews the technical aspects of the recommendation alone.

1.5 Please confirm, otherwise explain, that the OGC considers and reviews what FEI has proposed as mitigation in response to the OGC order and does not consider or review any other potentially suitable alternative mitigation.

1.5 OGC Response:
The Engineering Assessment submitted as per the OGC order fulfills that requirement of the order. The Engineering Assessment recommended replacement of the pipeline. Any application for an approval to replace this pipeline would be reviewed when it is submitted to the OGC; the OGC reviews what is submitted in the application to ensure that the design put forward meets the relevant Acts, Regulations and Standards.

If you have any further questions please don't hesitate to get back to us.

Sincerely,

James Nazareth
Supervisor, Pipelines & Facilities
BC Oil & Gas Commission

cc. Frank Austin, Deputy Commissioner, Pipelines, Facilities, D&P, OGC
Jason Wilson, Engineer, Pipelines & Facilities, OGC

Attachment 21.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)