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March 28, 2019

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598988

Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On December 17, 2018, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-11-19 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, page 1 and page 4, Fig. 1-1, and page 73, Table 5-13, General

The referenced page states:

1.1.1 CPCN for IGU Project

The IGU Project is needed to mitigate the potential for rupture failure due to corrosion on 29 transmission pipeline laterals on FEI's system that were constructed between 1957 and 1998, have a nominal pipe size (NPS) 6 or greater, operate as transmission pipelines and are not capable of being in-line inspected (referred to in this Application as the 29 Transmission Laterals). FEI owns and operates approximately 3 thousand kilometres of transmission pressure (TP) pipelines in the province of British Columbia. The 29 Transmission Laterals collectively make up approximately 410 kilometres of pipe length. Because the 29 Transmission Laterals operate at transmission operating stress levels, there is a potential that corrosion in these pipelines, if left undetected, could result in rupture.

1.1 Can FEI confirm that the 29 transmission pipeline laterals were the only transmission pipeline laterals constructed between 1957 and 1998? If not, please explain why other transmission pipelines laterals constructed during this period do not require attention at this time.

Response:

Not confirmed. The 29 Transmission Laterals are not the only transmission pipeline laterals constructed between 1957 and 1998. Please refer to the response to BCUC IR 1.8.2 for a description of other transmission pipeline laterals and the response to CEC IR 1.1.3 for FEI's corrosion monitoring strategies for other transmission pipelines that fall outside the scope of the IGU Project.

Other transmission pipeline laterals constructed during this period do not require attention at this time because they are either: capable of ILI, operated below 30 percent SMYS, or are pipe diameters of less than NPS 6. For the laterals that are less than NPS 6 and above 30 percent SMYS, FEI currently employs Modified ECDA and will continue to monitor available technology and industry practice for mitigating the potential for rupture due to corrosion.

The single remaining transmission lateral that meets the criteria for inclusion within the IGU Project is the Tilbury LNG 168 mm pipeline. Please refer to the response to BCUC IR 1.5.1 for a discussion of why this pipeline was excluded from the scope of the IGU Project.

1.2 Has FEI constructed or had constructed any other transmission pipeline laterals after the period 1957-1998? If so, is it reasonable to assume that any such laterals constructed soon after 1998 are likely to require similar attention in the near future?

Response:

As discussed in the response to CEC IR 1.4.2, FEI has not constructed transmission laterals with obstructions preventing the use of ILI tools since 1998. Based on FEI's current knowledge of ILI tool capabilities and characteristics, the design and construction of new laterals without obstructions is straightforward.

1.3 On what (starting) date did FEI begin incurring costs for the subject project?

Response:

FEI began incurring costs in July 2017.

1.4 Please provide the actual costs, by month, incurred to date on this project.

Response:

The table below shows the actual costs, by month, incurred on the IGU Project to date (February 2019):

Month	Total, Excl. AFUDC ($)	Cumulative ($)
2017-07	8,487	8,487
2017-08	8,083	16,571
2017-09	20,505	37,075
2017-10	6,258	43,333
2017-11	33,170	76,503
2017-12	429,525	506,029
2018-01	(53,729)	452,299
2018-02	45,004	497,303
2018-03	433,263	930,566
2018-04	225,848	1,156,414
2018-05	438,850	1,595,264
2018-06	334,555	1,929,819
2018-07	229,301	2,159,120
2018-08	270,217	2,429,337
2018-09	289,911	2,719,248
2018-10	341,134	3,060,383
2018-11	191,801	3,252,183
2018-12	198,578	3,450,762
2019-01	70,188	3,520,950
2019-02	45,533	3,566,483

1.5 On what date did FEI first identify the need for this project? That is, please provide the date on which FEI first became aware of the corrosion-rupture possibility on the subject transmission pipeline laterals.

Response:

Please refer to the response to CEC IR 1.3.6.

1.6 Prior to the instant application, did FEI specifically mention the need to address transmission pipe lateral integrity in any previous filing to the BCUC? If so, please provide details.

Response:

This response also addresses BCOAPO IR 1.1.7 and 1.1.8.

FEI mentioned the need to address the transmission pipe lateral integrity or the IGU Project in the following previous filings to the BCUC.

The TPIP 2005 Activities Report, submitted April 13, 2006, stated:

> While the [ECDA] process is believed to improve the level of safety with respect to external corrosion, Terasen Gas recognizes that there are limitations inherent within the ECDA assessment methodology. Electrical surveys used to measure levels of cathodic protection and coating quality are not able to detect areas that may be shielded from cathodic protection and are also unsuitable for the evaluation of cased pipeline segments. Due to these limitations, in-line inspection may be warranted in [the] future for some assets that are not currently retrofitted for ILI.[1]

TPIP 2006 Activities Report, submitted July 16, 2007, stated:

> …in-line inspection may be warranted at some future time for some assets that are not currently retrofitted for ILI.[2]

TPIP 2007 Activities Report, submitted April 30, 2008, stated:

> …in-line inspection may be warranted at some future time for some assets that are not currently retrofitted for ILI.[3]

FEI's Annual Review for 2017 Rates (submitted September 21, 2016), response to BCUC IR 1.9.11 from stated:

> FEI expects ongoing evolution of its in-line inspection program. Significant current initiatives under evaluation include: …

[1] TGI TPIP 2005 Activities Report, p.3.
[2] TGI TPIP 2006 Activities Report, p.4.
[3] TGI TPIP 2007 Activities Report, p.3.

- The need for and feasibility of adopting in-line inspection technology to inspect all transmission pipelines operating at hoop stresses of 30% or more of the specified minimum yield strength (SMYS) of the pipe.

FEI's Annual Review for 2018 Rates (submitted September 26, 2017), response to BCUC IR 1.1.9 stated:

> As an update to FEI's response to BCUC IR 1.9.11 in the FEI Annual Review for 2017 Rates proceeding, notable initiatives related to in-line inspection and integrity management currently being undertaken by FEI include: …
>
> - Provision of in-line inspection capability to NPS 6 outside diameter and larger transmission pipelines operating at hoop stresses of 30% or more of the specified minimum yield strength of the pipe.

FEI's Annual Review for 2019 Rates (submitted September 18, 2018), response to BCUC IR 1.1.5 stated:

> FEI's progress on the above initiatives, including a discussion of impacts on cost pressures, is as follows: …
>
> - With respect to provision of in-line inspection capability to NPS 6 outside diameter and larger transmission pipelines operating at hoop stresses of 30 percent or more of the minimum yield strength of the pipe, FEI is planning to submit a CPCN application for the Inland Gas Upgrades Project later in 2018 to address this issue. The pipelines within the scope of the Inland Gas Upgrades Project will require varying levels of O&M and Sustainment Capital expenditures over their lifecycle depending on the proposed integrity management solution for each of the pipelines. The proposed solutions include an ongoing ILI program (e.g. recurring ILI tool runs, data analysis, integrity digs, etc.), the installation and/or upgrade of pressure-regulation facilities to reduce the operating stress of the line, and pipeline replacement. Forecasts of expenditures are under development.

FEI first included a discussion of the IGU Project in Section 6.4 of the FEI's 2017 Long Term Gas Resource Plan (LTGRP), recently accepted by the BCUC per Order G-39-19 on February 25, 2019. Below is the excerpt from the LTGRP:

Transmission System Laterals In-Line Inspection (ILI) Capability

FEI operates transmission pressure laterals across the province served from either FEI operated transmission systems, the Westcoast pipeline or TransCanada and ranging from several hundred meters to several tens of kilometres in length. A total of more than 400 km of these pipeline laterals are between NPS 6 and NPS 10 and currently are not configured to allow ILI tools to be used as part FEI's pipeline integrity management programs. ILI technology is an effective tool for detecting and subsequently repairing pipeline corrosion and defects prior to leaking or rupture. FEI is currently investigating the cost and justification to install tool launching and receiving facilities and remove existing pipeline obstructions on up to thirty-one lateral pipeline segments.

FEI also included a discussion of the IGU Project in FEI's Application for a Multi-Year Rate Plan (MRP) for 2020 through 2024, filed on March 11, 2019. Below is an excerpt from the MRP in Section C3-3.3.3.1:

FEI Inland Gas Upgrades

Forecast Construction Timeline: 2020-2024

This project comprises upgrades to 29 gas transmission pipelines of NPS 6 and larger that do not currently have ILI capability in order to meet FEI's objective of further reducing the external corrosion hazard and/or limiting potential consequences associated with time-dependent threats. Upgrades are primarily comprised of retrofits to enable ILI (≈ 360 km), although other alternatives are being recommended due to lower impact and/or reduced cost. Pressure regulation is being recommended for ≈ 55 km of line, with pipe replacement recommended for ≈ 8 km of line. This project has been filed with the BCUC as a CPCN.

1.7 Please provide a copy of any capital spending plan(s) or other documentation or references to such filed with the BCUC within the last five years.

Response:

In the last five years, FEI has included capital expenditures forecasts and/or discussion in its LTGRP[4], in the Annual Reviews[5] under its Performance Based Ratemaking plan[6], and in its recently-filed 2020-2024 Multi-Year Rate Plan Application[7]. All of these proceedings can be found on the BCUC's website.

1.8 Please provide any previous filings to the BCUC that refer to or mention the transmission pipeline lateral issue that is the subject of the instant application. In the alternative, please provide specific references that detail the filing of such information with the BCUC.

Response:

Please refer to the response to BCOAPO IR 1.1.6.

1.9 Are the subject laterals currently in compliance with all applicable safety and integrity standards (e.g., CSA, BC OGC etc.)?

Response:

Yes. As stated in the response to CEC IR 1.18.2, the IGU Project is necessary to maintain compliance with FEI's legal and regulatory obligations. .

[4] https://www.bcuc.com/ApplicationView.aspx?ApplicationId=617.
[5] Annual Reviews of Rates for:
2019: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=639.
2018: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=592.
2017: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=556.
2016: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=507.
2015: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=479.
[6] https://www.bcuc.com/ApplicationView.aspx?ApplicationId=400.
[7] https://www.bcuc.com/ApplicationView.aspx?ApplicationId=667.

1.10 To FEI's knowledge, are FEI's other transmission and distribution pipe infrastructure fully in compliance with all applicable safety and integrity standards (e.g., CSA, BC OGC etc.)?

Response:

Yes.

1.11 To FEI's knowledge, are there other projects, similar in nature (pipeline integrity/safety) and in rate impact, upcoming in the near to medium future?

Response:

To FEI's knowledge, the only other project upcoming in the near to medium future that is similar in nature (pipeline integrity/safety) to the IGU Project is the Transmission Integrity Management Capabilities (TIMC) project. As discussed in section 12.4.1.1 of FEI's Annual Review for 2019 Delivery Rates, FEI currently expect to submit a CPCN application to the BCUC for the TIMC project in 2020. As the development work is still in progress, it is too early for FEI to evaluate whether the rate impact of the TIMC project will be similar to the IGU Project.

2.0 Reference: Exhibit B-1, Project Justification and Exhibit A-4, BCUC IR 3.0 preamble

2.1 Please provide either (i) references in the evidence or, otherwise, (ii) a table listing the relevant sections of safety/integrity rules, regulations, laws, and subsequent revisions/amendments that are applicable to the subject laterals of the instant application.

Response:

The BC Oil and Gas Activities Act (OGAA)[8] and the associated BC Pipeline Regulation (BC Reg. 147/2014)[9] and referenced standards comprise the overarching legal requirements for the safe operation of transmission pipelines. Key legal requirements applicable to FEI and the IGU Application are as follows:

Legal Requirement	Significance / Relevance to Application
Section 37 (1) (a) of the OGAA states, "A permit holder, an authorization holder and a person carrying out an oil and gas activity must prevent spillage"[10]. This requirement pertains to pipelines operating at or above a pressure of 700 kPa.	FEI's primary objective with its Integrity Management Policy and Integrity Management Program (IMP-P) – Pipelines is to prevent failure incidents that could result in significant safety, environmental, and/or reliability consequences. FEI has obligations as a Permit Holder under the OGAA to prevent all release of product from its BC Oil and Gas Commission ("BC OGC") regulated pipeline system. This obligation influences FEI's selection of asset management strategies over the lifecycle of a pipeline, with preference given to a methodology (such as ILI) that provides FEI with the capability to monitor and proactively respond to potential changes to asset condition that occur with time. OGAA applies to pipelines operating at or above 700 kPa, without consideration to the operating hoop stress of a pipeline. The 29 Transmission Laterals operate at or above 700 kPa.

8 http://www.bclaws.ca/Recon/document/ID/freeside/00_08036_01

9 http://www.bclaws.ca/civix/document/id/complete/statreg/281_2010

10 "Spillage", as defined in the OGAA, means "petroleum, natural gas, oil, solids or other substances escaping, leaking or spilling from (a) a pipeline, well, shot hole, flow line, or facility, or (b) any source apparently associated with any of those substances."

Legal Requirement	Significance / Relevance to Application
Section 3 (1) (a) of the Pipeline Regulation mandates that the design, construction, operation and maintenance of pipelines be in accordance with the Canadian Standards Association (CSA) Z662[11] standard. Section 7 (1) (a) of the Pipeline Regulation requires FEI to have a pipeline integrity management program for its pipelines operating at or above 700 kPa that complies with CSA Z662 and Annex N of CSA Z662.	The CSA Z662 standard is a consensus-based standard that is regularly reviewed and updated by a committee of qualified industry representatives including operators, suppliers and regulators. FEI employees actively participate in this process by serving as members on various Z662 committees. The Z662 standard applies to all of FEI's gas system assets, through the Pipeline Regulation (for assets operating at a pressure of 700 kPa or higher) and through the Gas Safety Regulation (for assets operating at a pressure of less than 700 kPa). The CSA Z662 standard applies to the 29 Transmission Laterals. FEI's IMP-P is based on CSA Z662.
Clause 1.4 of Z662-15 states: "This Standard is intended to establish essential requirements and minimum standards for the design, construction, operation, and maintenance of oil and gas industry pipeline systems. This Standard is not a design handbook, and competent engineering judgment should be employed with its use." (Source: Clause 1.4, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[12]	While the CSA Z662-15 standard requires FEI to have "procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data" (CSA Z662-15, 10.3.1), the standard is not explicit in its definition of how this should be achieved. In addition to legislation and standards, FEI has developed its IMP-P in consideration of it's assessment of relevant hazards for an aging pipeline system, it's understanding of industry practice, and evolving technology available for assessing and managing pipeline condition.

11 "CSA Z662", as defined in the Pipeline Regulation, means "the standard published by the Canadian Standards Association as CSA Z662, Oil and Gas Pipeline Systems, as amended from time to time." It is typically republished every 4 years, with the most recent version being released in June 2015 and hence is referred to as CSA Z662-15 in this Application.

12 With the permission of Canadian Standards Association, (operating as "CSA Group"), 178 Rexdale Blvd., Toronto, ON, M9W 1R3, material is reproduced from CSA Group's standard **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. This material is not the complete and official position of CSA Group on the referenced subject, which is represented solely by the Standard in its entirety. While use of the material has been authorized, CSA Group is not responsible for the manner in the which the data is presented, nor for an representations and interpretations. No further reproduction is permitted. For more information or to purchase standard(s) from CSA Group, please visit store.csagroup.org or call 1-800-463-6727.

Legal Requirement	Significance / Relevance to Application
Clauses 3.2 and 10.3.1 of CSA Z662-15 require FEI to develop and implement an Integrity Management Program for its entire pipeline system that includes procedures to monitor for conditions that can lead to failures and to eliminate or mitigate such conditions. Clause 3.2 Pipeline system integrity management program states: "The operational controls required by Clause 3.1.2 f) v) shall be in the form of an integrity management program that addresses the life cycle of the pipeline system." Clause 10.3.1 Pipeline system integrity management program states: "The pipeline system integrity management program required by Clause 3.2 shall include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data. Such integrity management programs shall include a description of operating company commitment and responsibilities, quantifiable objectives, and methods for a) assessing risks; b) identifying risk reduction approaches and corrective actions; c) implementing the integrity management program; and d) monitoring results." (Source: Clause 3.2 and 10.3.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[13]	The list of identified hazards addressed by FEI's IMP-P is modeled using CSA Z662 Annex H and company operating experience: • Third party damage; • Natural hazards; • Pipe condition; • Material defects and Equipment failures; and • Human factors. Pipe condition is the primary focus of this Application, and in particular FEI's practices for managing the time-dependent hazard of external corrosion for its transmission laterals.

[13] Ibid.

Legal Requirement	Significance / Relevance to Application
Clause N.13.2.1 of CSA Z662-15 requires that "pipeline systems with indications of imperfections shall be subject to detailed visual inspection, mechanical measurement, non-destructive inspection, as appropriate, for the type of pipeline system and evaluation as specified in Clause 10.10", unless demonstrated by an engineering assessment that the imperfections are not associated with defects. (Source: Clause N.13.2.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[14]	ILI technology has been developed and improved over the recent past decades to detect and size various imperfections. In determining response to ILI data, operators rely significantly on information obtained from integrity digs (an integral step within FEI's in-line inspection process).
CSA Z662-15 defines a "Distribution system, gas" as "the main and service lines, and their associated control devices, through which gas is conveyed from transmission lines or from local sources of supply to the termination of the operating company installation …" (Source: Clause 2.2, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[15]	FEI's IMP-P contains differing objectives, and therefore different activities and/or activity levels, for its transmission versus distribution pipeline system.
CSA Z662-15 defines a "Line, transmission" as "a pipeline in a gas transmission system that conveys gas from a gathering line, treatment plant, storage facility, or field collection point in a gas field to a distribution line, service line, storage facility, or another transmission line." (Source: Clause 2.2, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[16]	This Application comprises laterals considered as part of FEI's transmission pipeline system.
CSA Z662-15 Clause 12.1.1 under the main Clause 12 (which is entitled "Gas distribution systems") contains the following note: "Where specifically referenced, some requirements are applicable to piping for systems other than gas distribution systems, provided that any steel piping is intended to be operated at hoop stresses of less than 30% of the specified minimum yield strength of the pipe." (Source: Clause 12.1.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[17]	For the purposes of its Pipe Condition activities, including ILI, FEI's IMP-P differentiates assets (and associated activities) by their operating hoop stress expressed as a percentage of the specified minimum yield strength (SMYS) of the pipe. This is because the potential for rupture failure due to external corrosion is mitigated for an asset operating at less than 30% SMYS.

[14] Ibid.
[15] Ibid.
[16] Ibid.
[17] Ibid.

Legal Requirement	Significance / Relevance to Application
Clause 12.1.2 of CSA Z662-15 states: "Clause 12 does not apply to steel distribution or service lines intended to be operated at hoop stresses of 30% or more of the specified minimum yield strength of the pipe." (Source: Clause 12.1.2, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[18]	Clause 12.1.2 necessitates that FEI not apply the distribution-related requirements of Z662 to laterals operated at hoop stresses of 30% or more of the specified minimum yield strength of the pipe.
Clause 12.10.3.3 (d) of CSA Z662-15 states: "Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they are not suitable in service, they shall be replaced, reconditioned, or abandoned." (Source: Clause 12.10.3.3 (d), **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[19]	This Clause implies that it may be appropriate for an operator of a gas distribution system to wait for an occurrence of leaks on its system prior to implementing IMP-P activities intended to manage hazards and consequences. In determining its lifecycle integrity management strategies for pipelines operated at hoop stresses of less than 30% of the specified minimum yield strength of the pipe, but with an operating pressure at or above 700 kPa, FEI balances its consideration of this clause relative to its obligation as a Permit Holder under Section 37 (1) (a) of the OGAA to "prevent spillage".

Note that the table above does not list requirements pertaining to recurring operational activities such as CP surveillance and leak detection.

[18] Ibid.
[19] Ibid.

3.0 Reference: Exhibit B-1, pages 10 and 129 - 130, and Exhibit A-4, BCUC IR 33.x series,

Indigenous Consultation and Engagement

The second referenced page (129) states:

8.3.5 Outstanding Issues or Concerns

A number of Indigenous communities expressed interest in working on the Project in some capacity. Follow up meetings will be scheduled with these communities as additional information around contracting and procurement becomes available.

Some concerns such as those related to sensitive areas require additional, site specific information that is not available at this early Project stage. FEI will continue to engage with those communities that have requested additional information with follow up meetings as the Project design becomes more certain.

3.1 Can FEI confirm that no issues of law or jurisdiction – which could impact the project or its timing – have been raised by Indigenous communities thus far?

Response:

Based on its engagement with Indigenous communities to date, FEI confirms that it has not been informed of any issues of law or jurisdiction that could impact the IGU Project or its timing.

3.2 Does FEI expect that there will be no material objections forthcoming from Indigenous communities with respect to this project? If so, please explain fully.

Response:

Based on responses from Indigenous communities received to date, and meetings that FEI has participated in as detailed in Table 8-3, FEI is not aware of any material objection to the IGU Project.

Not all Indigenous communities have responded to FEI's notification letter; however, FEI will continue to engage with all Indigenous communities identified in Section 8.3.2 of the Application to ensure they receive opportunities throughout project development to provide input into the IGU Project.

The page 130 states:

> All Indigenous communities will be sent a follow up letter advising them of the filing of this CPCN application.

3.3 Please confirm whether FEI has informed affected Indigenous communities that the Application has been filed and how to raise concerns with the BCUC.

Response:

FEI confirms that a notification letter was mailed on January 21, 2019 to potentially impacted Indigenous communities identified in Section 8.3.2 of the Application, advising that the Application was submitted to the BCUC on December 17, 2018.

The following paragraph from the notification letter indicates how to raise concerns as an interested party or intervener:

> "As a regulated utility, we must have projects like this reviewed and approved through a rigorous and transparent process with the BCUC. If [Nation Name] wish to register as an interested party or submit a request to intervene in the application process, information on how to get involved can be found at www.bcuc.com. We have been informed by the BCUC that the registration deadline is set for February14, 2019. All related documents filed on the public record are on the "Current Proceedings" page on the Commissions website."

3.3.1 If confirmed, please reference when this occurred.

Response:

Please refer to the response to BCOAPO IR 1.3.3.

3.3.2 If not confirmed, please explain why this has not happened.

Response:

Please refer to the response to BCOAPO IR 1.3.3.

4.0 Reference: Exhibit A-4, BCUC IRs 7.1, 7.11, and 7.12, FEI's 2014-2019 PBR Plan

4.1 In FEI's view, did FEI have a financial incentive to either (i) defer or (ii) not defer the bulk of the spending on or associated with the subject project until the end of the approved PBR plan? Please explain why or why not.

Response:

There is no financial incentive for FEI to defer or not defer the IGU Project until the end of the approved PBR plan. The cost of the IGU Project is well above the materiality threshold of $20 million approved by the BCUC for the current PBR plan in Order G-120-15, and therefore the capital spending on the IGU Project is excluded from the capital expenditure formula within FEI's current PBR plan.

Only after the Application is approved by the BCUC, and the assets are constructed and placed into service, will the assets be added to rate base. As shown in Table 6-4 of the Application, the IGU Project will be completed and placed into service over a five-year period, from 2020 to 2024, which is after the current PBR plan has come to an end.

5.0 Reference: Exhibit B-1, Section 4, Description and Evaluation of Alternatives

5.1 For the subject 29 transmission pipeline laterals, can FEI confirm that had it chosen – in each case – the lowest cost alternative that would "meet code" the overall cost of the project would not be significantly lower?

Response:

FEI confirms that in all cases but one, the lowest cost alternative was selected. In that one case (the Elkview Lateral 168), FEI selected the PRS alternative which had a $46 thousand higher PV of its revenue requirement over the 66-year analysis period compared to PLR. Please refer to the responses to BCUC IRs 1.18.4 and 1.18.5 for discussion of FEI's rationale for choosing PRS for this lateral.

In all cases, FEI selected the most appropriate alternative based on the following evaluation criteria: Integrity and Asset Management Capability, Project Execution and Lifecycle Operation, and Financial. Please refer to Section 4.3 of the Application for a full description of the evaluation methodology.