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September 6, 2024

Movement of United Professionals
c/o Allevato Quail & Roy, Barristers and Solicitors
405-510 West Hastings St.
Vancouver, BC
V6B 1L8

Attention: Jim Quail

Dear Jim Quail:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC)

Application for Approval of a Rate Setting Framework for 2025 through 2027 (Application)

Response to the Movement of United Professionals (MoveUP) Information Request (IR) No. 1

On April 8, 2024, FortisBC filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-165-24 for the review of the Application, FortisBC respectfully submits the attached response to MoveUP IR No. 1.

For convenience and efficiency, if FortisBC has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FortisBC intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1.0 TOPIC: HOW SHOULD WE GO ABOUT ORGANIZING OURSELVES FOR THE TASK OF RATE- SETTING IN THE EMERGING ENVIRONMENT?

REFERENCE: EX. A-2, Commission Question 1:

1 Given FortisBC's statement that energy transition impacts will "ultimately have an effect on FortisBC's rates," please explain when, if not now, a FortisBC Rate Framework would be expected to address the energy transition's effects on rates.

AND REFERENCE EX. B-2 Response to Commission Question 3 page 18 – 19:

36 It is important to recognize that the Rate Framework covers a three-year term, whereas the energy
37 transition is expected to unfold over many years. At this time, there is considerable uncertainty
38 for both FEI and FBC, which is why FortisBC has proposed and emphasizes the need for flexible
39 approaches to rate-setting mechanisms in the Application. This challenge was acknowledged by
1 the BCUC in its decision approving BC Hydro's reconsideration of the Performance Based
2 Regulation Report (BC Hydro Reconsideration Decision)
. . . .
24 FortisBC agrees with many of the statements made by the BCUC in the BC Hydro
25 Reconsideration Decision. The energy transition has created increased cost uncertainty, and
26 there will likely be an increase in costs that are driven by external factors outside of FEI's and
27 FBC's control. Further, FortisBC agrees that given the increased uncertainty faced by utilities,
28 adopting a "new and untested regulatory regime" should be avoided.
. . . .
33 Accordingly, while FortisBC agrees (and has stated in the Application) that the energy transition
34 requires that the Companies evolve and adapt their operations, the Rate Framework itself should
35 be well understood and should be flexible enough to respond to the cost uncertainty created by
36 the energy transition.

REQUEST:

1.1 Does FortisBC expect that the amplitude of its contextual uncertainty will diminish or increase as climate change intensifies over the coming years? On what basis?

1.1.1 Would an extended period of uncertainty call for an extended period of stasis in the evolution of regulatory processes, or for directing greater urgency to considering ways to adapt to changing conditions? Please explain.

Response:

The energy transition and climate change create uncertainty for both FEI and FBC; however, the speed or amplitude at which the changes (and uncertainty regarding the changes) will occur is unknown. Both FEI and FBC need to continue to adapt and respond to the changing conditions; however, as explained in the response to BCUC Panel Supplemental IR 1, these substantive actions will be largely addressed in separate proceedings, through important applications such as the Companies' long term resource plans, demand side management expenditure plans, major project applications, rate design applications, and energy supply agreements and plans. The primary purpose of the Rate Framework is to establish a flexible and efficient rate-setting

framework that supports FortisBC's ability to provide affordable, reliable, and resilient service to customers, and FortisBC considers that the Rate Framework is flexible enough to manage the rate impacts which may result from the uncertainties in the external environment, including from the energy transition.

Regarding regulatory processes more generally (i.e., beyond the Rate Framework), FortisBC considers there to be a balance between the frequency of regulatory processes and the resource burden and costs that regulatory processes create for the utilities and their customers. Regulatory applications that may better lend themselves to greater process changes are long term resource plans. FortisBC understands, for example, that BC Hydro has proposed a new "living" long-term resource planning cycle, with more regular filings, beginning with its next integrated resource plan (IRP), and that the BCUC supported this approach in the BC Hydro 2021 IRP Decision and Order G-58-24.[1]

FortisBC considers that its rate frameworks (i.e., the 2014-2019 PBR Plan, Current MRP and the proposed Rate Framework) operate somewhat similarly and have evolved to become akin to an evergreen-type framework. Over the past decade, FortisBC has implemented a rate-setting approach which provides for substantial review and re-setting of the components of the multi-year rate plans (including a basing of formulaic O&M and regular capital) approximately every five years. In the intervening years, the Companies provide annual forecasts and updates through the Annual Review process, which provides the BCUC and interveners a touch point each year to examine targeted aspects of the Companies' performance and upcoming years' forecasts, as well as any new and/or unexpected events that have arisen during the year, such as significant weather events or the impacts of the COVID-19 pandemic.

However, the process to establish the rate frameworks could further evolve to be more of an evergreen approach. For example, instead of doing a full re-examination of each of the framework components every five years (or potentially three years in the current situation if the Rate Framework is not extended beyond the proposed three years), the Companies could, in consultation with the BCUC staff and interveners, identify specific components of the framework to form the basis of the detailed review in each three to five year review cycle. Then, in the intervening years, the Companies would continue with the Annual Review process to set rates annually. Such an approach would recognize that not all components of the rate plan may need to be re-examined on the same frequency and would allow the Companies to better focus on their responses to the changing external environment brought on by the energy transition and climate change, while still providing the Companies, the BCUC and interveners an opportunity to undertake a detailed examination of elements of the rate framework and revenue requirement with some frequency. Further, an evergreen approach should balance the need for periodic evolution with the need for a long enough term to effectively incent the development and implementation of initiatives under the plan (e.g., efficiency initiatives).

[1] Pages 42-43.

REFERENCE: EX. B-2, response to Commission Question 6 at page 32:

4 In summary, FortisBC's jurisdictional review indicates that:
5 • there has been no significant change in the utility remuneration paradigm (the review of
6 the revenue requirement to set rates is still essential);

REQUEST:

1.2 What analysis has FortisBC conducted of alternatives to either the cost-of-service or the performance-based rate-setting frameworks?

Response:

Please refer to the response to BCUC Panel Supplemental IR 8 which discusses the feasible alternatives to the proposed Rate Framework. The spectrum of rate-setting approaches generally ranges from a traditional cost-of-service based approach to a pure performance-based approach, with options within this spectrum that utilize components of performance-based and cost-of-service based rate-setting. FortisBC is not aware of any other alternatives outside the mentioned spectrum of rate-setting approaches that can satisfy the relevant legal and regulatory standards, such as the Fair Return Standard and Regulatory Compact, that are applied to investor-owned utilities in North America.

1.3 Is FortisBC aware of analyses or experimentation, including in academia or in other jurisdictions, of potential new approaches to utility rate-setting (beyond refinements or adaptations of these traditional mechanisms) that are designed to address the emerging challenges and imperatives? (Is there anyone out here who is thinking outside of the two boxes inherited from the last century?)

Response:

As correctly identified in the question, the existing utility remuneration paradigm has been developed and evolved over 100 years and is based on sound legal and regulatory standards. Therefore, as recognized by the Ontario Energy Board (OEB) in its 2023 report titled "Framework for Energy Innovation" (formerly known as Utility 5 Remuneration; EB-2018-0287), while identifying new or modified approaches to utility remuneration may be needed to adapt to the demands of the energy transition, this would be a lengthy and complex process. However, by addressing the most narrowly scoped issue at hand to facilitate near-term progress, it can inform the broader consideration of the utility remuneration. In other words, the changes to the existing utility remuneration scheme would likely be carried out as part of a small but regular set of

evolutions rather than a revolution. Indeed, as discussed below, the regulation of investor-owned utilities in North America is constantly evolving to adapt to the dynamic nature of utility operations and government policy.

The existing utility remuneration model for investor-owned utilities is based on rate-of-return regulation. Under this model, the utility's ability to grow its earnings is primarily dependent on its approved cost of capital, as well as its ability to prudently grow its rate base. While the fundamentals of this model have not changed, there has been a number of innovations to adapt this model to the desired policies and changing utility operating environment. For instance, in the 1980s, utilities were given additional responsibilities for energy efficiency and conservation programs that would not have been aligned with the incentives inherent in the rate of return regulation. The utility remuneration model therefore evolved to remove these disincentives by either allowing the utilities to treat their energy efficiency and conservation related costs as part of the rate base, or to allow utilities to use Performance Incentive Mechanisms (PIMs) to be remunerated for these activities in the form of return premiums or other incentives.

More recently and given the massive investment required to respond to the energy transition and the need for affordable energy, there has been a push by regulators and other stakeholders to once again evolve the utility remuneration model to remove disincentives for utilities to include Distributed Energy Resources (DER) or Non-Wire and Non-Pipe Alternatives in their integrated distribution planning. Some initiatives, such as New York's Reforming Energy Vision (REV), state that they aim to change the utility business model by motivating distribution companies to view themselves as a "platform" on which third party suppliers of various distribution-level services can compete, similar to the operating platforms developed by technology companies where the developers use the platform to sell their products and services and pay a fee to the platform owner. In practice, however, and as discussed by Paul Joskow, Professor of Economics at the Massachusetts Institute of Technology (MIT) and former Director of the MIT Center for Energy and Environmental Policy Research, these initiatives are incremental to the rate of return regulation and rely on regulatory tools such as PIMs to incent utilities to pursue certain desired outcomes:[2]

> Some commissions have introduced an ad hoc set of additional performance incentives that have been targeted at specific initiatives to give the distribution utilities incentives to experiment with adapting to state climate policies and changes in the structure of the electric power industry.
>
> New York's Reforming Energy Vision (REV) framework is an example. While I think that there is more hype than substantial regulatory reform in this regulatory framework in practice, it does represent an important view of the changing business model for distribution utilities in the era of growth of DER, distribution level storage, non-wires options for responding to distribution system reliability and congestion issues, and a growing interest in some states in spurring third-party solutions to grid development needs that are allowed to compete with the

[2] https://ceepr.mit.edu/wp-content/uploads/2024/01/MIT-CEEPR-WP-2024-01.pdf; p. 31.

incumbent distribution utility's proposals. REV seeks to motivate distribution companies to view themselves as a "platform" on which third party suppliers of various distribution-level services can compete with the distribution company. When a third party is selected to provide the services, the distribution company receives a financial incentive to compensate it for an estimate of its lost profits from choosing a third party to meet the need. The NYPSC envisions that the revenues and earnings from these third-party services will grow over time.

Overall, FortisBC expects the existing utility remuneration model to evolve over time to remove the potential disincentives to adapt to the needs of the energy transition, but is not aware of any analyses or experimentation that could fundamentally change this model. Ultimately, any changes to the current regulatory model should provide the utilities with the flexibility to adapt and respond to the uncertainties and evolving requirements created by the energy transition.

1.4 If the Commission approves the Rate-Setting Framework for a multi-year term, in FortisBC's view what would be the most effective process, in the meanwhile, for the Commission to examine whether more effective modes of rate-setting might be developed or adopted?

Response:

FortisBC does not consider it necessary for the BCUC to examine whether there are more effective modes of rate-setting over the term of the Rate Framework, as FortisBC considers its multi-year rate frameworks to be flexible and effective.

However, as explained in the response to MoveUP IR1 1.1, there could be an opportunity to develop a more evergreen approach to FortisBC's rate frameworks. Such an approach could be considered as part of the review process for this Application, or as part of the process to determine if the Rate Framework should be extended beyond three years, which FortisBC proposes to undertake in 2027. Please refer to the response to RCIA IR1 7.1 for a discussion of how such a process could be undertaken in 2027. However, adding an additional process during the term of the Rate Framework as suggested in the question would be inefficient and undermine the benefits of the length of the Rate Framework.

REFERENCE: EX. B-1 pages A-1 to A-2:

26 The Current MPR has performed well in a rapidly evolving external environment, including
27 unprecedented pressure on rates for both gas and electric operations, driven by factors that are
28 external to FortisBC's historical operations.

29 Key influences in the operating environment that are becoming increasingly predominant are:
30 • Policy direction and mandate from all levels of government towards decarbonization;
31 • Challenges related to energy affordability; and
32 • Addressing physical and cyber security, climate adaptation, and the ongoing need to
33 invest in FortisBC's energy systems.

1 FortisBC continues to evolve its rate setting frameworks in response to the rapidly evolving
2 operating environment, which has highlighted the critical interrelationships between the gas and
3 electric systems and the need to provide dependable service to customers during times of peak
4 demand, whether driven by load growth or by shifts in energy use between systems, or between
5 times of the year, week, day, or hour. A key focus of this Application is on proposing flexible rate
6 setting mechanisms that recognize the uncertainty inherent in the energy transition and that
7 manage its impacts on the provision of affordable, reliable, and resilient service to customers in
8 the face of heightened concern around the impacts of climate change, as well as physical and
9 cyber security risks on BC's energy systems.

AND REFERENCE: EX. B-1 page C-50:

16 2.3.3.2 Long-Term Resource Planning

17 Long-term resource planning is a critical function for FortisBC as it assesses the future energy
18 requirements of customers and options to meet them over the long-term, providing the context
19 and framework for future regulatory applications, including CPCNs. The requirement to submit
20 long-term resource plans to the BCUC is set out in section 44.1 of the UCA. During the ongoing
21 energy transition and the rapidly changing external environment, FortisBC's resource planning
22 activities are becoming less cyclical and more ongoing, with long-term resource plans being
23 developed and filed with the BCUC on a more frequent basis. With new sources of supply such
24 as wind and solar, and new types of customer demand such as EV charging and hydrogen
25 production, resource planning has increased in complexity.

REQUEST:

1.5 In FortisBC's view, what are the implications of the emerging context of disruptive change and uncertainty on the optimum relationship between the processes of utility resource planning (i.e., integrated resource planning) and utility resource acquisition (i.e., rate-setting)?

Response:

Regardless of the changes in the external environment due to the energy transition (or other factors), FortisBC considers that long term resource planning and rate-setting should remain separate and distinct processes that inform one another. However, as explained in the response to MoveUP IR1 1.1, it may be reasonable for each of these processes to evolve to be more evergreen in nature.

The long-term resource plan is important for providing the long-term outlook of expected energy demand and how this demand will be met, as well as the anticipated system investments that will be required. Due to their length, the 20-year forecasts provided in the long-term resource plan are necessarily based on a variety of assumptions about the future, and are reflected in a range of potential future scenarios, such as FEI's Deep Electrification Scenario and Diversified Energy Planning (DEP) Scenario presented in the 2022 LTGRP. The forecasts (including rate forecasts)

provided in the long-term resource plans are necessarily only indicative due to the uncertainty of how the future will actually unfold.

However, long-term resource plans are not a substitute for rate-setting, which is dealing with the Companies' near-term expectations of load/demand, O&M and capital expenditures, and the annual overall impact of the annual forecast revenue requirement on rates. Based on these inputs, the Companies propose the annual rate changes, which may also require smoothing through the use of deferral accounts. All of these considerations are best made within the rate-setting application, as this is the place where the rate impacts of all revenue requirement components (some of which have been approved through separate applications such as CPCNs or DSM Plans) can be assessed for the upcoming year, and a proposal for rates can be made in accordance with sections 59 to 61 of the *Utilities Commission Act* (UCA).

1.6 Does this context suggest that revisiting how IRP should inform rate-setting would be timely? (and if not in this Application, when?)

Response:

Please refer to the response to MoveUP IR1 1.5.

1.7 In broad strokes, in FortisBC's view, how should the functional relationship between IRP and rate-setting operate in the emerging context?

Response:

Please refer to the response to MoveUP IR1 1.5.

1.8 What changes in rate-setting processes over the coming period might help maintain its responsiveness to continuous and accelerating contextual change?

Response:

Please refer to the response to MoveUP IR1 1.1.

1.9 Please discuss to what extent it would be useful to develop more "evergreen" mechanisms for rate-setting, analogous to the developmental direction of resource planning, in order to:

a. Improve the coherence of the relationship between these two processes,

b. Ensure that rate-setting (and generally resourcing utility operations and projects) is optimally responsive to disruptive change and uncertainty, and

c. For any other purposes?

Response:

Please refer to the responses to MoveUP IR1 1.1 and 1.5.

2.0 TOPIC: FEI – IMPLICATIONS OF DECLINING RATE OF ATTACHMENTS AND POTENTIALLY DECLINING CUSTOMER COUNT AND DELIVERY THROUGHPUT

REFERENCE: EX B-1 page B-8:

22 Energy Transition Impacts on FEI

23 FEI's focus continues to be on reducing emissions while also providing safe, affordable, reliable,
24 and resilient service to customers. The development and refinement of climate policy has led to
25 uncertainty over what the future role of the gas system will be. Provincial policy is driving towards
26 reducing emissions by 40 percent by 2030 and 80 percent by 2050, with ambitions to achieve Net
27 Zero emissions across BC's economy. The most direct impacts of this policy environment on FEI
28 are the potential for a decline in customer attachments, lower throughput through energy
29 efficiency requirements, and increased cost pressures for customers due to investments in
30 emissions abatement (e.g., investments in renewable and low carbon gas and energy efficiency
31 initiatives).

AND REFERENCE: EX. B-1 page C-10:

18 1.5 GROWTH FACTOR FOR FEI'S AND FBC'S INDEXING FORMULAS

19 FortisBC proposes to maintain the average number of customers as the growth factor for FEI's
20 and FBC's O&M indexing formulas and to continue to use the Gross Customer Additions (GCA)
21 as the growth factor for FEI's Growth capital formula. Further, similar to the approach approved
22 in the MRP Decision,45 FortisBC proposes to continue to use a forecast with subsequent true-up
23 mechanism for the growth factor.

AND REFERENCE: EX. B-2 Response to Question 2 page 15

30 For example, FEI is proposing to maintain the current formulaic approach for both O&M and
31 Growth capital, which is dependent on the forecast of average customer counts and new customer
32 attachments, respectively, with a true-up for actuals (based on a two-year lag). Therefore, as
33 FEI's customer growth or overall customer counts decline, the formulaic approach is flexible such
34 that FEI's funding for Growth capital and O&M will be adjusted to reflect a decline.

REQUEST:

2.1 Please discuss in detail the extent to which the impacts of positive and negative customer growth are asymmetrical in relation to operating costs. That is, does the loss of 1000 customers reduce operating costs to the same extent that the addition of 1000 customers increases operating costs, and to what extent, and in what manner, and over what time-frames?

Response:

The following response was provided by Dr. Kaufmann:

It is difficult to assess these scenarios since Dr. Kaufmann does not have the data needed to measure some of the requested outcomes, especially the costs associated with the "loss of customers". However, three important cost concepts can shed light on these issues. These cost concepts are: (1) economies of scale; (2) peak costs; and (3) fixed costs. The implications of these cost characteristics are addressed below.

(1) Economies of Scale

First, it is widely acknowledged that gas and electricity distribution networks exhibit economies of scale. Indeed, the presence of scale economies is critical for gas and electricity networks to be characterized as "natural monopolies," whose services can be provided more efficiently by price-regulated monopolies rather than through competitive markets.

When economies of scale exist, unit costs of service[3] will decline as output expands. Thus, an increase of 1,000 customers will generate scale economies that reduce a utility company's unit costs. It is also important to realize that scale economies is a long-run cost concept, and it does not depend on the shares of variable and fixed costs (to be discussed below), as is sometimes believed. Therefore, in the long run, if an increase of 1,000 customer numbers is followed somewhat later by a 1,000 decrease in customers, all else held equal, unit costs will be unchanged.

(2) Peak Costs

However, the "all else held equal" proviso mentioned above will not in fact be true for gas and electricity networks. One important reason is that to serve all customers demanding service throughout the year, gas and electricity delivery networks are "sized" to meet peak demands on their systems. Designing networks to accommodate peak demands means that if 1,000 customers (whose demands are at least in part coincident) are lost, customer deliveries of gas and/or electricity will also fall.

However, when these declines in output are experienced, the delivery network has already been designed to serve the larger, previous peak load, and serving a larger peak load necessarily increases the cost of the network. Therefore, the need to size networks to serve peak demands means that the loss of load resulting from the loss of 1,000 customers will reduce output (i.e., throughput) but not reduce the cost of the energy delivery network.

This increase in the unit cost of the existing network will be offset over time. For example, the loss of 1,000 additional customers would likely reduce the utility's incremental capital expenditures associated with customer growth. The loss of customer growth will therefore have offsetting effects on the company's overall unit costs, which means the unit cost impact of losing 1,000 customers is in principle ambiguous. The net impact depends on the relative magnitudes of the increased unit cost of installed assets when customer numbers decline, and the decrease in unit costs resulting from fewer incremental, growth capital expenditures.

[3] Unit costs are equal to costs divided by a measure of output. They can be measured in a number of different ways. For example, unit costs can vary depending on the type of cost considered (e.g., total costs, O&M costs) and different types of output measures (e.g., customer numbers served, total throughput). Total cost per customer is one example of a unit cost. O&M cost per customer is an example of another type of unit cost.

(3) Fixed Costs

This logic involves a third important cost concept: fixed costs. Energy networks sized to meet peak demand rely on a variety of long-lived capital goods to move natural gas and power downstream to customers. It is not economic to replace these assets before the end of their useful lives, so these "fixed assets" provide service for long periods of time and associated "fixed costs" recover the costs of these assets for many years.

Fixed assets therefore continue to have cost consequences for years after they have been installed. This is true even if customer numbers decline, since it is not practical or cost-effective to adjust fixed assets in response to transitory output fluctuations. A loss of 1,000 customers therefore reduces output but has minimal impact on fixed asset costs.

FortisBC adds the following response:

All of FortisBC's expenditures are related to and in support of providing safe and reliable service for customers. All costs are variable in this sense, with total costs increasing/decreasing as the throughput and number of customers served increases/decreases. This is consistent with the commonly expressed economic perspective that all costs are variable over the long run. The issue and debate is how costs behave in the short term compared to their behaviour in the long run, how these short run and long run time periods are defined, and how this variability is appropriately reflected in the funding mechanisms for FortisBC's O&M expenditures. In the short term, some of FortisBC's O&M costs are fixed (i.e., leases, rent), some are semi-variable (i.e., vehicle costs – insurance portion fixed while fuel costs variable based on vehicle usage) and some variable (i.e., customer billing and postage). FortisBC is unable, however, to provide an accurate estimate of what portion of its O&M costs are fixed, the portion of historical O&M costs for FEI and FBC that are reasonably impacted by the changes in the average number of customers or system throughput, and specifically identify the O&M expenses which are impacted by these changes.

For example, in the case of adding an industrial customer which is typically much more costly than adding an additional residential customer, the Company is likely underfunded based on the proposed formulaic funding mechanism using the proxy O&M per customer. Significant industrial customer additions, likely not reflected in the O&M per customer Base used, will cause O&M funding pressures for the Companies. Additionally, there may be situations where there may be increases in costs not anticipated that in the short run are not the direct result of an increase in customers or throughput. Examples of this include facilities rent/lease increases, changes in municipal regulations and related fees, higher vehicle operating costs including fuel charges and insurance, increases in corporate safety programs and activities, and changes in environmental regulation. FortisBC recognizes that the same examples can result in both increases or decreases to its O&M expenditures and are not the direct result of an increase in customers or throughput.

The O&M per customer represents and includes a composite of a number of costs and a number of factors affecting the costs and provides a reasonable proxy for expected changes in O&M costs. Cost changes in some categories are more than the change in average number of customers or use per customer (for instance there are cost increases that can happen without

adding a single additional customer), some costs change on a 1:1 basis with increases in customers (e.g., billing and other customer care-related costs), and some costs may not change in the short run with the change in average number of customers or throughput. Recognizing that there will not be a perfect relationship between adding/losing one customer (or one unit of energy) and incurring a certain amount of O&M funding at the aggregate level, FortisBC's proposal incorporates the O&M per customer concept as a reasonable proxy.

2.2 What are the implications of any asymmetry of impact between positive and negative customer growth on the design of the proposed rate-setting mechanism for FEI (including the proposed formulaic application of customer additions to rate-setting?)

Response:

The following response was provided by Dr. Kaufmann:

Dr. Kaufmann does not believe that "asymmetry of impact between positive and negative growth" has any implications for the design of the proposed rate-setting mechanism. The response to MoveUP IR1 2.1 addresses the issue of capital growth under the proposed "positive and negative growth" scenario, but changes in FEI's Growth capital expenditures are addressed directly in its mechanism. Any changes in costs associated with customer growth are also reflected directly, and fully, in the customer growth components of the mechanisms. Accordingly, there is no need to modify the customer growth elements of the mechanisms, and any such adjustments will lead to double-counting of the relevant costs.

FortisBC adds the following response:

Under the proposed O&M formulas, the increase or decrease in the number of customers are treated symmetrically, meaning that a one percent increase or decrease will lead to an equal amount of increase or decrease to the formula driven O&M.

While the relationship between the number of customers and O&M costs is not one-to-one (due to the existence of fixed O&M costs), any economies of scale are already reflected in the formulas' base unit O&M and the industry productivity factor. Further, any company specific adjustments to the operating costs to account for the negative and/or positive customer growth can be reflected in the rebased costs at the beginning of the plan.

With regards to FEI's Growth capital formula, the base growth capital is increased by the growth in gross customer additions which by definition cannot be a negative number. In the case where FEI has no customer additions, its Growth capital will only grow by I-X.

2.3 Please discuss in detail the extent to which the impacts of positive and negative commodity throughput growth are asymmetrical in relation to operating costs.

Response:

Regarding the impact of positive and negative throughput and customer numbers on utility costs, please refer to the response to MoveUP IR1 2.1.

Positive or negative changes to throughput growth would have no impact on FEI's and FBC's formula driven costs. This is because the formulas' growth factors are not based on changes in throughput but rather are based on average number of customers (for FEI's and FBC's O&M formulas) and gross customer additions (for FEI's proposed Growth capital formula).

FEI is proposing to continue recording variances between forecast and actual delivery rate revenue in the Flow-through deferral account, as discussed in Section C4.13.2. FEI is also proposing to record variances in commodity related costs in the existing Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA), as discussed in Section C4.3.1 of the Application. As such, the impact of positive or negative throughput trends is symmetrical for FEI in terms of commodity costs and delivery revenues, as all variances will be returned to or recovered from customers through the amortization of these deferral accounts.

FBC is similarly proposing to continue to record variances between forecast and actual power supply costs (which includes cost variances due to load variances) as well as revenue in the Flow-through deferral account. As such, the impact of positive or negative throughput trends is also symmetrical for FBC in terms of power supply costs and revenue.

2.4 What are the implications of any asymmetry of impact between positive and negative throughput growth on the design of the proposed rate-setting mechanism for FEI?

Response:

Please refer to the response to MoveUP IR1 2.3.

REFERENCE: EX. B-1 page B-10:

1 1.4.3 Flexibility is Vital to Both FEI and FBC

2 Despite differing impacts on gas and electric operations from the energy transition, FortisBC has
3 filed one common Rate Framework application. This is because the flexibility inherent in the
4 proposals in this Application are designed to allow for increases and decreases in both cost and
5 demand levels driven by the energy transition. In Section B3.2 of the Application, FortisBC
6 describes how the specific elements of the Rate Framework address the energy transition and
7 other influences in the Companies' operating environments.

8 FortisBC's priority remains on delivering safe, reliable, and affordable energy in an increasingly
9 low carbon future. The sections below describe the impacts of the energy transition on affordability
10 for the critical energy needs of customers, and how population growth, the energy transition and
11 environmental influences more broadly are requiring increased investments and greater diligence
12 to maintain a safe, reliable, and resilient system.

AND REFERENCE: EX B-1 page B-50:

10 3.2.3 Elements Specific to FBC

11 FBC is affected by the energy transition differently than FEI. FBC is focused on investing in
12 capacity to accommodate increases in load, whether coming from electric vehicles or from
13 customers moving to electricity from other fuels. In addition, the need to respond to climate
14 impacts through investments in climate adaptation is more acute for FBC compared to FEI due to
15 FBC's above-ground grid.

2.5 If FBC's and FEI's respective metrics (customer counts and volumes of energy delivery) are set to move in opposite directions over the coming period, why would the same metrics and formulas apply to adequately resource the operating and capital costs of both utilities?

Response:

The following response was provided by Dr. Kaufmann:

There is no basis for adjusting the incentive regulation mechanism itself if FEI's and FBC's customer numbers and delivery volumes move in opposite directions. Any such adjustments to the inflation factor, productivity factor, stretch factor, or customer growth factor would be arbitrary and undermine appropriate cost recovery principles and the Companies' performance incentives.

FortisBC adds the following response:

FortisBC notes that the average number of customers for both FEI and FBC is forecast to increase during the Rate Framework term, albeit the percentage of growth for FEI is likely to be lower than recent years. Further, as discussed in the responses to MoveUP IR1 2.1 and 2.3, under the proposed Rate Framework, the formulas are flexible enough to accommodate the positive or negative customer growth scenarios, negating the need to use different formulas.

3.0 TOPIC: FEI'S FORMULAIC GROWTH CAPITAL PROPOSAL

REFERENCE: EXHIBIT B-1 page B-13:

2 1.6.2.1 Continued Customer Attachments
3 British Columbia continues to grow in population and FEI continues to experience new customer
4 attachments each year, though over the past three years, the number of new gross customer
5 attachments has been declining, from approximately 20 thousand in 2021 to less than 16
6 thousand in 2023. FEI expects this trend to continue in 2024, with gross customer attachments
7 projected to be in the range of 11 to 12 thousand. Given the range of future scenarios within the
8 energy sector, construction industry, and municipal and governmental rules and restrictions, the
9 growth trajectory for future years remains unpredictable. This unpredictability, combined with the
10 policies discussed in Section B1.3, will impact gross customer attachments. FEI has proposed a
11 formulaic approach to Growth capital that is responsive to changes in customer attachments to
12 manage this uncertainty.

REQUEST:

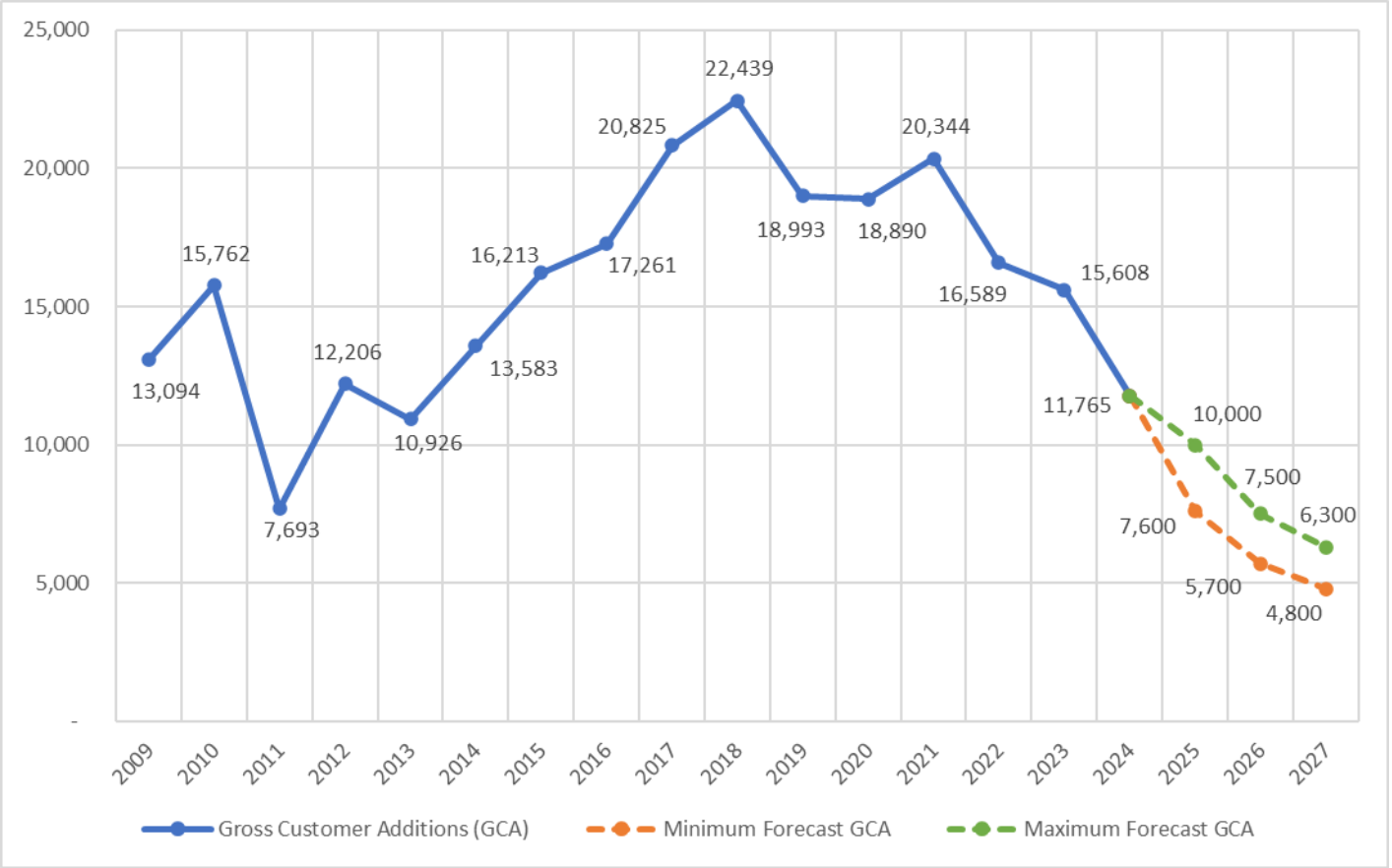
3.1 Please provide a chart or table illustrating FEI's customer attachment trends over the past eight years and projected range of potential attachments over each year of the proposed term of the rate plan.

Response:

Please refer to Figure 1 below for the actual/projected Gross Customer Additions (GCA), which represent new customer attachments to the gas distribution system from 2009 to 2023 Actuals and 2024 Projected, as well as an estimated maximum and minimum range of GCA for 2025 to 2027.

In order to illustrate the full range of GCA historically, FEI included the Actual GCA from 2009 to 2015 in addition to the most recent eight years requested (i.e., 2016 to 2023), thus providing the customer attachment trend over the past 15 years. As shown in the figure below, while FEI is currently projecting the GCA will continue to decline over the proposed three-year Rate Framework term, the level of GCA is not significantly different than the level seen between 2011 and 2013.

Figure 1: FEI's Gross Customer Additions (Actuals from 2009 to 2023, Projected 2024, and Estimated Range for 2025 to 2027)



3.2 Please discuss the scenario for FEI growth capital if its overall net rate of customer growth is flat or negative, while attachments continue to increase in some regions of its service territory. How does the proposed mechanism provide necessary flexibility to respond to divergent trends within its service territory? Would any modifications to the proposed mechanisms improve this outcome?

Response:

FEI's Growth capital formula is based on gross customer additions (i.e., new customer attachments or connections). It is not based on average number of customers or net customer additions that would include customers that move in and out of premises as well as disconnections.

Although FEI does not expect the overall net rate of customer growth will become flat or negative in the next three years (as discussed in the response to BCUC IR1 8.5), FEI's Growth capital

formula is nonetheless flexible and will continue to enable new customer attachments regardless of the overall net rate of customer growth.

There is also no regional restriction to FEI's Growth capital; as such, there is no modifications needed for divergent trends within its service territory.

Further, FEI notes that there is a true-up mechanism for the variances between actual and forecast GCA in the Growth capital formula. Therefore, FEI considers its proposed formulaic approach to Growth capital is very flexible and produces reasonable results.

4.0 TOPIC: TOPIC: ANNUAL REVIEWS

REFERENCE: EX. B-1 page B-26:

2.2.2.1 A Multi-year Rate Plan Framework
In the 2020-2024 MRP Application, FortisBC described the benefits of a multi-year rate plan framework as:
• Reduced regulatory costs and internal efficiencies associated with the streamlined regulatory process;
• Increased utility focus on managing the business with a long-term view; and
• Increased operational flexibility to address the increasing pace and growing scope of energy industry transformation.

In this regard, FortisBC believes the benefits over traditional cost of service regulation were largely achieved; however, as shown in Tables B2-6 and B2-7 below, the efficiencies in costs and effort expended in the Annual Review process have started to erode. In fact, the total number of information requests (IRs) combined for FEI and FBC in 2024 marked an increase to almost the same level as the number of IRs that FortisBC received in 2015, which was the first Annual Review of the 2014-2019 PBR Plan term.

REQUEST:

4.1 Please confirm that according to Table B2-7 the average number of IRs filed in annual reviews for both utilities combined, under the 2014-2019 PBR, was 683.4

Response:

Confirmed. The total number of IRs asked in the Annual Reviews for both utilities during the 2014-2019 PBR Plan term was 3,417, resulting in an average of 683.4 IRs per year, and the total number of IRs asked in the Annual Reviews for both utilities during the 2020-2024 MRP term was 2,657, resulting in an average of 664.25 IRs per year.

Although the average number of IRs was lower during the 2020-2024 MRP term as compared to the 2014-2019 PBR Plan term, the number of IRs in 2024 represented a 15.3 percent increase over the 2014-2019 PBR Plan annual average and an 18.6 percent increase over the 2020-2024 MRP annual average.

4.2 Please confirm that according to Table B2-7 the average number of IRs filed in annual reviews for both utilities combined, under the 2020-2024 MRP, was 664.25

Response:

Please refer to the response to MoveUP IR1 4.1.

4.3 How many times has either FortisBC utility objected to annual review IRs on any basis including materiality? What percentage of total IRs has this represented?

Response:

FEI has no record of objecting to or declining to respond to IRs in Annual Review proceedings, and FBC has a record of objecting to or declining to respond to eight IRs in various Annual Reviews over the 2014 to 2024 timeframe.

While this represents 0.13 percent of the total IRs, it is not reflective of how many IRs were potentially out of scope or only tangentially relevant to the proceedings. The Companies' approach with respect to IRs is to be as responsive as possible, and given the compressed timetables for the Annual Reviews, the utilities rarely object to IRs because the process by which to object often takes more time than responding to the IR, even if it is out of scope or not material to the decision in the proceeding. Instead, FortisBC has proposed improvements to the Annual Review process that address observed scoping issues as these issues are more efficiently addressed in this proceeding.

REFERENCE: EX. B-1 page B-45:

3.2 KEY FEATURES OF THIS RATE FRAMEWORK THAT ADDRESS THE ENERGY TRANSITION

To address the energy transition and other influences in FortisBC's operating environment, and in consideration of the existing flexibility and features of its Current MRP and stakeholder feedback received, FortisBC's key proposals for the Rate Framework are as follows:

1. A term that provides incentive to perform and the capacity to focus on key issues, while acknowledging the current level of uncertainty in the operating environment;

2. Sufficient funding to address emerging requirements and challenges;

3. Flexibility to adapt to the energy transition to manage its costs and impacts; and

4. An efficient annual rate-setting process that allows the Companies to focus on responding to the energy transition operationally and through key regulatory filings focused on the energy transition.

AND REFERENCE EX. B-2 page 9:

The Annual Reviews Provide a Regular Opportunity to Consider Rate Impacts

FortisBC has been addressing rate impacts during each year's Annual Review for both FEI and FBC under the Current MRP term and will continue to do so under the proposed Rate Framework. FortisBC considers the Annual Reviews remain the most appropriate forum to address rate impacts, when all aspects of FEI's and FBC's revenue requirement are identifiable, including all available offsetting benefits, before determining if a rate mitigation strategy is required. This approach has been successfully implemented during the previous PBR Plan term as well as the Current MRP term. Given that the level and pace of rate impacts during the energy transition for

both FEI and FBC is uncertain at this time, using the Annual Reviews to address ongoing rate impacts is a flexible approach, regardless of whether the impact is due to the energy transition or other factors. For example, both FEI and FBC proposed and received approval during the Annual Review for 2024 Rates proceedings to defer a portion of the rate impact resulting from the BCUC's GCOC Stage 1 Decision. The impact on FEI's and FBC's revenue requirements of the GCOC Stage 1 Decision occurred outside of the Current MRP's framework; however, the Annual Review process within the Current MRP framework provided the forum to determine how best to incorporate the revenue requirement impacts into FEI's and FBC's rates.

AND REFERENCE: EX B-1 page C-21:

The primary area where FortisBC considers that regulatory efficiency can and should be improved in the Annual Review process is in clearer scoping of topics permitted to be explored in IRs (or at the workshop.

REQUEST:

4.4 What is the impact of the context of disruptive change and uncertainty on the significance of annual reviews in the proposed rate-setting plan?

Response:

The Annual Review process is, and will continue to be, an important and regular touch point for the Companies, the BCUC and interveners. The Annual Reviews have always had a high level of importance and have facilitated the review and discussion of topics related to rate-setting, service quality, the energy transition, and the Companies' responses to unprecedented events such as the COVID-19 pandemic. Providing an opportunity annually to undergo a review process, including the opportunity for face-to-face (or virtual) interaction with all parties through the Workshops, are important and appropriate forums for reviewing the impact that the energy transition (and other factors) is having each year on rates.

Please also refer to the response to BCUC IR1 10.4, which clarifies the intent of explicitly scoping the Annual Review process.

4.5 If FortisBC believes that the importance and appropriate scope of annual reviews will not be greater over the coming period than it was in the past, please explain the basis for this belief in detail and reconcile it with the overall scheme of the rate-setting plan.

Response:

Please refer to the response to MoveUP IR1 4.4.

4.6 How does FortisBC reconcile its assertions that annual reviews are a key feature of the rate framework to "address the energy transition and other influences in FortisBC's operating environment" and that "FortisBC considers the Annual Reviews remain the most appropriate forum to address rate impacts, when all aspects of FEI's and FBC's revenue requirement are identifiable, including all available offsetting benefits, before determining if a rate mitigation strategy is required" with its proposal that the Commission institute measures at the outset of annual review proceedings (prior to the filing of IRs or workshops) to restrict the scope of topics that Commission staff and interveners are permitted to raise?

Response:

Please refer to the response to MoveUP IR1 4.4.

4.7 How does FortisBC propose that scope-restriction exercise would be administered?

Response:

FortisBC proposes that the BCUC determine whether the proposed items are approved to be out-of-scope for the Annual Reviews as part of the BCUC's decision on this Application, similar to how the BCUC in the MRP Decision (page 167) determined the framework for the Annual Reviews during the Current MRP term. However, instead of describing the in-scope items in its decision, the BCUC would identify the out-of-scope items. This way, the out-of-scope items are explicitly identified instead of being implicitly identified. Please also refer to the response to BCOAPO IR1 11.4.

From an administration standpoint, FortisBC expects that if IRs are asked during the Annual Review process that clearly fall under the out-of-scope items, the utilities would identify the out-of-scope IRs and decline to respond to them. If there was ambiguity as to whether the IR was out-of-scope, then FortisBC would either respond to the IR for expediency or would seek a determination from the BCUC during the IR response process.

4.8 How does FortisBC propose that issues that emerge or become apparent in the course of annual review proceedings after a scope-restriction order is made could be addressed?

Response:

FortisBC expects that new issues that emerge during the Annual Review process could be addressed as part of that Annual Review, consistent with how new issues have been addressed during the 2014-2019 PBR Plan term and Current MRP term. FortisBC does not consider that an increased degree of change or uncertainty, and any increase in issues resulting from such change or uncertainty, will impact the ability to address issues during the Annual Reviews.

Please also refer to the responses to BCUC IR1 10.4 and BCOAPO IR1 11.4.

4.9 Does the context of disruptive change and uncertainty increase or decrease the likelihood of such issues arising?

Response:

Please refer to the response to MoveUP IR1 4.8.

4.10 Does FortisBC believe that a tighter initial scoping process for annual reviews will enhance transparency and the confidence of interveners and the public in its rate-setting plan and resultant rates? Please explain.

Response:

FortisBC does not consider that the proposed scoping will have an impact on the transparency of, and confidence in, the rate-setting process. As discussed in the response to BCUC IR1 10.4, with the exception of the demand/load forecast methods, FortisBC's scoping proposal improves regulatory efficiency by merely clarifying the items that are already considered out-of-scope under the Current MRP. FortisBC continues to view the Annual Reviews as important touch points for the Companies, the BCUC and interveners.

Ultimately, FortisBC considers that the Annual Reviews, as proposed, will provide an opportunity for a transparent and thorough examination of issues, just as they have over the past decade.

4.11 How problematic is it if Commission staff or interveners ask questions in an annual review workshop that utility participants consider immaterial to the outcome or otherwise marginal?

4.11.1 If a participant in an annual review workshop asks a question that utility participants consider immaterial or marginal, why is this not a useful opportunity to explain the reasons for this opinion rather than refuse to respond to the question?

Response:

FortisBC does not consider it problematic for BCUC staff or interveners to ask questions in the Annual Review Workshops that may be considered immaterial to the outcome. FortisBC values the opportunity to interact directly with the BCUC and interveners through the Workshops, and has rarely objected to questions being asked by any party which may be less relevant or tangential to the Application. During the term of the Rate Framework, FortisBC will continue to seek to respond to questions at the Workshop even if they are considered to be of marginal relevance.

4.12 How willing is FortisBC to withdraw this proposal and instead continue to rely on its right to object to IRs?

Response:

FortisBC sees no basis to withdraw its proposal for scoping the Annual Reviews. Please also refer to the response to BCUC IR1 10.4.

REFERENCE: EX. B-2 Commission Question 3 page 22

26 Ultimately, the BCUC's decision on both FEI's and FBC's annual review proceedings declined to
27 provide any specific direction and left the form of the next rate application up to FEI and FBC.

REQUEST:

4.13 In FortisBC's view, what are the respective roles of the Commission, regulated utilities, and interveners in regulatory paradigm development? How might this be effectively undertaken?

Response:

FortisBC considers that the roles of the public utility, the BCUC and interveners in the development of rate frameworks are largely determined by the jurisdiction of the BCUC as set out in the *Utilities Commission Act* and other relevant legislation.

Following this legislation, in British Columbia, public utility rate frameworks have evolved through successive ratemaking proceedings which provide a form of ongoing dialogue between the public utility and the BCUC which is informed by intervener participation. The public utility prepares its rate applications taking into account any past directions or guidance of the BCUC, as well as any information gathered through consultation with BCUC staff and interveners. In some cases, the public utility may be under a direction from the BCUC to pursue a particular type of rate framework and, in other cases, such as the present one, the BCUC may leave the type of rate framework up to the utility to propose. In either case, the public utility plays a key role in developing the details of the rate framework suitable for its particular circumstances. In addition to directions and guidance from the BCUC, the public utility will consider its experience with its past rate frameworks, its current operating environment, and expectations for the upcoming test period, and may look to the rate frameworks and experience in other jurisdictions to inform its rate application. Further, all rate frameworks must comply with the applicable legislative and common law requirements in effect at the time, which may constrain the range of ratemaking options available.

Once the rate application is filed, the BCUC determines the regulatory process for review of the application, including the role of interveners. Generally, interveners pose information requests to the utility and make submissions on the application and may file evidence of their own. The BCUC considers the public utility's evidence as well as any input from interveners and issues a decision on the application, approving or denying the rate proposal in whole or in part, and providing any direction to the utility for the subsequent application.

The utility then considers the BCUC's decision, including any specific directions, its ongoing experience and the experience of other utilities, in preparing its next rate application. FortisBC considers this ongoing process to be an effective one that allows for rate frameworks to evolve in an informed and careful way that fits within the bounds of legislation.

4.14 Does FortisBC take the position that an annual review is not an appropriate venue for the Commission to receive input and provide a utility with guidance of that nature?

4.14.1 If it is not appropriate, how would the utility and other participants be heard on those issues over the course of a rate-setting cycle?

4.14.2 Does FortisBC support a process during the term of a rate plan for the consideration of rate-setting methodology changes to guide the preparation of the succeeding cycle? If so, what form might this take and when should it occur? If not, why not?

Response:

FortisBC considers the purpose of the Annual Reviews in the proposed Rate Framework to be the same as they have been for the past decade, and is proposing some additional clarification to the scope as part of this Application, as explained in the response to BCUC IR1 10.4.

FortisBC's rate frameworks have always incorporated a process to guide the preparation of the succeeding cycle (e.g., this process has occurred at the conclusion of both the 2014-2019 PBR Plan term and the 2020-2024 MRP term). In the case of the proposed three-year term for this Rate Framework, FortisBC proposes that the review process for the succeeding cycle (which may be a proposal to extend the Rate Framework for one or more years) occur in 2027, as explained in the response to RCIA IR1 7.1. However, as explained in the response to MoveUP IR1 1.1, FortisBC considers that further evolution of the rate frameworks could occur to make the process more evergreen.

5.0 TOPIC: O&M - PROPOSED NEW POSITIONS

REQUEST:

5.1 With respect to each of the new employee positions that FortisBC intends to establish under the Rate-Setting Plan, please indicate whether it will be located in management or in either of the bargaining units.

Response:

FortisBC considers the appropriate location (i.e., M&E or bargaining unit) for a position at the time that a posting is requested, which is expected to occur in early 2025. Any position determined to be within the jurisdiction of either union is posted as a union-represented position. While FortisBC expects the new positions will be a mix of Management & Exempt (M&E) and unionized positions, it has not yet conducted this analysis.

6.0 TOPIC: CAPITAL

REFERENCE: EX. B-1 page C-70:

3.2.1.1 Energy Transition

The energy transition impacts on capital planning differ for FEI and FBC. For FEI, given the uncertainty over future gas demand levels driven by climate policy, capacity driven projects have been reviewed to ensure they meet the needs of the shorter-term system demand forecast. While the need for an upgrade is determined through normal capacity planning processes, FEI has reviewed the size of the upgrade (length/size of system improvement or capacity of station) with a view to shorter timelines. Typically, a longer-term capacity forecast (20 years) is utilized to ensure any upgrades can address the requirements of the system without having to upgrade again in the near future, with the goal of ensuring investments are as efficient as possible and costs are minimized. With the development of this capital plan, and with the recent pressures of decarbonization and electrification in local communities, FEI has reviewed the proposed capacity driven projects to assess if they can be re-scoped into multiple smaller capacity upgrades so that FEI can proceed with only the portions that meet the underlying need for the near term. FEI expects this process to be iterative over the coming years.

For FBC, the energy transition is expected to increase demand across the service territory. With growth driven by electrification and building code changes as well as the growing adoption of electric vehicles, FBC is working to better understand the potential impacts on its existing system and is in the process of identifying and planning for investments to support the continued growth in demand for new load.

REQUEST:

6.1 Does FEI intend to undertake capital projects specifically in order to assist its response to energy transition?

Response:

FEI currently has undertaken, and will continue to undertake, capital projects within its regular capital spending to assist in the response to the energy transition. FEI provides the following examples of capital investments that support the energy transition:

- Methane emission mitigation to respond to changing regulations requiring alterations to FEI's existing infrastructure. As explained in Section C3.3.4.1 of the Application, FEI anticipates that it will be seeking flow-through treatment for capital expenditures related to methane emission mitigation during the term of the proposed Rate Framework.
- RNG facilities such as the RNG facility at the City of Vancouver's landfill, as well as interconnection of renewable gas supply projects. These projects are approved in separate applications outside of the Rate Framework.
- The Advanced Metering Infrastructure (AMI) project, which will provide customers with more granular data that can help them better understand and reduce their energy use. The AMI project was approved as a CPCN Application.

Regarding larger capital projects related to the energy transition, such as hydrogen-related projects, FEI may seek CPCN approval of capital expenditures. Please also refer to the response to BCUC IR1 18.2 which discusses the potential for hydrogen integration into FEI's system.

REFERENCE: EX. B-1 page C-67:

Consistent with the Current MRP, FEI's and FBC's Regular capital expenditures are divided into the following categories:

• Growth capital: For FEI, this consists of expenditures for the installation of new mains, services, meters, and distribution system improvements to support customer additions. For FBC, this consists of expenditures for infrastructure required to meet demand for new customers and/or load growth.

• Sustainment capital: For FEI, this consists of expenditures for meter exchange programs, replacements and upgrades to the distribution and transmission systems related to safety, integrity and reliability, and expenditures for mains and service renewals and alterations. For FBC, this consists of expenditures for system reinforcements, asset replacements, and upgrades to the generation, transmission, stations, and distribution assets, to ensure safety, integrity and reliability.

• Other capital: For both FEI and FBC, this consists of expenditures for IS, equipment (including fleet vehicles), and facilities.

REQUEST:

6.2 Where does capital investment to enable and to execute energy transition fit into this matrix?

Response:

Please refer to the response to MoveUP IR1 6.1.

REFERENCE: EX. B-1 page C-69:

The value that a capital investment contributes to each of these areas is calculated, taking into account the number of customers, employees or other stakeholders impacted, the magnitude of a potential event, the likelihood that an event will occur, the mitigating factors that are present and the impacts of time on risks and benefits. Once projects are evaluated using the value framework, the tool provides the ability to optimize the capital planning portfolio for a given period of time to achieve the greatest benefit within a set of financial and/or resource constraints.

The AIP process and tool supports risk-informed decision-making in capital planning by quantitatively valuing investments through a value framework that is common to all asset classes. FortisBC actively manages the planning and execution of its capital plan to achieve value for customers.

REQUEST:

6.3 How should capital investment to enable and to execute energy transition be evaluated? Is AIP capable of processing these issues? Please explain.

Response:

As explained in the response to MoveUP IR1 6.1, while some investment in energy transition-related activities occurs within regular capital, the majority of capital investment occurs through the annual forecasting of flow-through capital expenditures (i.e., Clean Growth Initiatives, including Methane Emission Mitigation expenditures as proposed) or may occur through separate applications for larger capital projects in areas such as hydrogen development.

For other projects that involve alterations to FEI's existing infrastructure for reducing GHG emissions or due to changing regulations, FEI considers Regulatory Compliance Risk as well as Environmental Impact Risk and Benefits within the Asset Investment Planning (AIP) Value Framework. FortisBC's AIP tool is capable of processing these issues, but it can be challenging to forecast capital expenditures related to regulatory compliance, especially when there is uncertainty around the timing and scope of new federal or provincial regulations, which is why FEI is proposing to apply for flow-through treatment of Methane Emission Mitigation capital expenditures during the Rate Framework term.

REFERENCE: EX. B-1 page C-73

Table C3-3: FEI Growth Capital Expenditures and UCGC 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
New Customer Mains	29,699	25,637	39,301	38,398	35,611
New Customer Services	49,794	58,291	58,819	60,376	54,127
New Customer Meters	4,690	4,125	4,011	4,287	2,840
System Improvements (DP)	1,153	3,452	4,718	14,477	22,248
Total Growth Capital (Gross)	85,336	91,505	106,848	117,538	114,826
CIAC	(1,791)	(1,719)	(1,850)	(1,688)	(1,252)
Total Growth Capital (Net)	83,545	89,786	104,998	115,850	113,574
Gross Customer Additions	18,890	20,344	16,589	15,608	11,765
Acrtual Unit Costs, Net (UCGC)	4,423	4,413	6,329	7,422	9,654

REQUEST:

6.4 Noting a disproportionate decrease in 2024 projected expenditure as between new services and new meters, with a large drop in meter expenditure: is this because

the unit cost of meters is more fixed and/or sensitive to the rate of additions? Please explain.

Response:

The disproportionate decrease in 2024 projected expenditures between new services and new meters is because the unit cost of meters is generally more stable, whereas 2024 new customer services is subject to increased contractor pricing and the cost of installation per service is sensitive to field conditions and complexity of installation.

7.0 TOPIC: REGIONAL GAS SUPPLY DIVERSITY PROJECT

REQUEST:

7.1 What is the present status of this project?

Response:

As part of the sixth quarterly progress report on the Regional Gas Supply Diversity (RGSD) Project, which was filed with the BCUC on April 30, 2024, FEI stated that it considers the RGSD Project as contemplated in the RGSD Application to have concluded and FEI will not be recording any further costs in the RGSD Development Account. FEI has completed its screening assessment for the RSGD Project and has concluded the following:

- It has become increasingly clear that the scope of the RGSD Project, including regional approaches to the RGSD Project, will likely not meet the timelines for some of the near-term market needs or avoid the Enbridge Sunrise project. The Enbridge Sunrise project has further developed, and FEI believes it now has a higher probability of proceeding to meet near-term market needs.
- FEI's investigation and screening revealed that, in order to mitigate risks to FEI's customers and achieve an optimal solution, any new regional infrastructure should be explored in collaboration with other market participants and consider integration with regional pipeline infrastructure. There is the potential for FEI to explore a regional infrastructure solution with other market participants. This new option, which would be a new project, would require co-commitments and support from other market participants. Thus, FEI will need to undertake commercial discussions to explore ways to best integrate FEI's existing pipeline infrastructure with the Enbridge T-South system. Any future project that may result from these commercial discussions would be a new project, and FEI would seek approval of this new project from the BCUC at the time the project is sufficiently progressed.

Pursuant to Order G-210-24 issued on August 8, 2024, the BCUC approved the discontinuance of FEI's quarterly progress reports and approved for FEI to cease recording costs in the RGSD Development Account. FEI expects to file an application to recover the balance in the RGSD Development Account in Q4 2024.

8.0 TOPIC: FBC POSTPONING CAPITAL PROJECTS THROUGH TERM OF PLAN

REFERENCE: EX. B-1 page C-103:

FBC successfully implemented a number of mitigation strategies to limit the impact of cost pressures, thus allowing FBC to manage the overall cost increases. These mitigation strategies included:

• Reprioritizing projects, or components of a project that could be safely re-scheduled to accommodate other project cost increases that could not be deferred. While FBC has delayed some work with flexible timing to accommodate the increased capital demands, this has only mitigated part of the capital pressures due to the magnitude of market and other pressures;

8.1 How will FBC avoid replicating problems in its past PBR terms arising from postponing capital projects for short-term savings resulting in accumulated costs being incurred in the latter part of the term?

Response:

FBC does not agree with the way the question has characterized its evidence in the Application.

FBC has re-prioritized projects during the term of the Current MRP to accommodate increased capital demands and other cost pressures, or in some cases due to changes in the timing of growth-driven projects. FBC has not postponed projects to achieve short-term savings and has been spending more than the approved forecasts in the last three years of the Current MRP term. The differences between the Actual/Projected and Approved regular capital forecasts are as follows:

- 2020 - $1.084 million less than approved
- 2021 - $0.758 million less than approved
- 2022 - $6.360 million higher than approved
- 2023 - $2.734 million higher than approved
- 2024 (Projected) - $3.043 million higher than approved

FBC explained on page C-104 of the Application that the key drivers of the increased capital forecasts, among others, include:

- Increased requirements for system improvements to the Transmission and Distribution systems to accommodate load growth; and
- Upgrades to existing assets, particularly Generation and Stations assets, to meet current codes and standards, to address the condition and age of assets, and to improve reliability.

Please also refer to the response to BCUC IR1 27.6 for further discussion on FBC's capital planning process.

9.0 TOPIC: SERVICE QUALITY INDICATORS – ALL-INJURY FREQUENCY RATE

REQUEST:

9.1 Please provide tables identifying the each of the 2023 injuries contributing to the reported tallies for each of FBC and FEI, showing in each instance the general nature of the injury, the work location, the category of employee (excluded, MoveUP, IBEW or contractor), the number of days' work lost, whether it resulted in a Worksafe compensation claim, and measures taken to avoid recurrence.

Response:

Please refer to the following tables for the recordable injuries for 2023 for each of FEI and FBC.

1 **Table 1: FBC Recordable Injuries for 2023**

Month-Year	General Nature of Incident	Total Days Lost	WSBC Claim	Affiliation	Work Location	Measures Taken to Avoid Recurrence
Jan-2023	Musculoskeletal Injury (MSI)	0	Yes	M&E	Kelowna	• Manager ensured the employee met with the Injury Prevention Specialist to discuss rehabilitation and prevention strategies. • Reviewed event at safety meeting, highlighted the need to exercise caution when working manually. Being aware of overexertion and planning to have a partner assist with strenuous activities.
Mar-2023	Irritation	8	Yes	IBEW	Trail	• Supervisor purchased alternative PPE to mitigate the hazard. • Reviewed event during safety meeting, highlighted the need to use battery cleaner when cleaning posts to reduce likelihood of particles going airborne.
May-2023	Laceration	1	Yes	IBEW	Kootenay Operations Centre	• Reviewed event during safety meeting, highlighted the need for caution when working with sharp tools, especially in congested and oily areas. Reminded employees to wear PPE gloves to mitigate the risk of personal injury.
May-2023	MSI	33	Yes	IBEW	Ymir	• Reviewed event during safety meeting, highlighted the need for caution when feeling any type of pain and discomfort. Provided overview of modified Stay at Work program for these situations with goal of preventing further injury. Reminded employees to utilize MoveSafe prior to conducting work. • Supervisor organized a meeting with employee and the Injury Prevention Specialist to discuss modified duties, rehabilitation strategies and good ergonomic practices while working from a bucket.
May-2023	MSI	8	Yes	IBEW	Creston	• Reviewed event during safety meeting, highlighted the need for proper ergonomics when conducting strenuous activities. Reviewed good habits such as MoveSafe and taking microbreaks. • Supervisor organized a meeting with employee and the Injury Prevention Specialist to discuss prevention strategies for their injury.
Jun-2023	Laceration	0	Yes	IBEW	Kootenay Operations Centre	• Reviewed event during safety meeting, highlighted Hazard Identification Risk Assessment (HIRA) and Safe Work Procedure (SWP) processes. Focused on covering or removing the sharp edge and wearing adequate cut resistant PPE gloves. • Added job step of brake dust collector duct to Job Hazard Analysis (JHA) for lower bracket removal.

Month-Year	General Nature of Incident	Total Days Lost	WSBC Claim	Affiliation	Work Location	Measures Taken to Avoid Recurrence
Jun-2023	Laceration	0	Yes	IBEW	Kootenay Operations Centre	• Reviewed event during safety meeting and reminded crews of the HIRA and SWP processes. Reminded crews when an event occurs on the worksite, the mechanism of injury needs to be adequately mitigated and communicated prior to work commencing.
Jul-2023	Laceration	0	Yes	MoveUP	Kelowna	• Reviewed event with the team and Joint Health & Safety Committee (JHSC), highlighted the need for caution when opening the parking lot gate because the gate drops down slightly creating a pinch point between the handle and top bar of the gate.
Sep-2023	MSI	5	Yes	IBEW	Kootenay Operations Centre	• Reviewed event with employees, highlighted the need for caution when working in congested areas and to ensure ergonomic positioning is maintained, especially for heavy loads.

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2 **Table 2: FEI Recordable Injuries for 2023**

Month-Year	General Nature of Incident	Total Days Lost	WSBC Claim	Affiliation	Work Location	Measures Taken to Avoid Recurrence
Jan-2023	MSI	0	Yes	IBEW	Kelowna	• Manager ensured the employee met with our Injury Prevention Specialist to discuss rehabilitation and prevention strategies. • Reviewed event at safety meeting, highlighted the need to exercise caution when working with manual tools. Emphasized the need to be aware of risks of overexertion and plan to have a partner assist with strenuous activities.
Jan-2023	Fracture	0	Yes	MoveUP	Surrey	• Discussed importance of stretching (MoveSafe) and reviewed proper workstation ergonomics with employees at safety meeting.
Jan-2023	MSI	14	Yes	IBEW	Kamloops	• Supervisor ensured the employee met with our Injury Management Specialist to discuss rehabilitation and prevention strategies.
Feb-2023	MSI	10	Yes	IBEW	Vernon	• Altered location of meter set for future work to avoid awkward positioning. • Supervisor reiterated the importance of reviewing different work methods available to complete a task, and the associated risks, during the Hazard Identification and Risk Assessment (HIRA) process, to minimize the potential for personal injury.

Month-Year	General Nature of Incident	Total Days Lost	WSBC Claim	Affiliation	Work Location	Measures Taken to Avoid Recurrence
Feb-2023	MSI	4	Yes	IBEW	Courtenay	• Developed safety communication for all field workers related to mobile heavy equipment, included a video featuring affected employees talking about lesson learned from the event and preventative actions for future work.
Feb-2023	MSI	2	Yes	IBEW	Tilbury	• Added a note to “watch your step on the deck of the truck” on the shunting Job Hazard Analysis (JHA). • Marked gaps and tripping hazards with reflective tape.
Mar-2023	MSI	10	Yes	IBEW	Burnaby Shops and Stores	• Purchased harnesses with more back support. • Encouraged participation in MoveSafe and incorporated stretches for the lower back.
Mar-2023	MSI	0	Yes	IBEW	Langford	• Manager ensured the employee met with our Injury Prevention Specialist to discuss rehabilitation and prevention strategies.
Mar-2023	MSI	18	Yes	IBEW	Surrey	• Reviewed event during safety meeting, highlighted the importance of MoveSafe, good body mechanics, and back wrenching techniques to help mitigate tight fittings. • Supervisor reiterated the importance of reviewing different work methods available to complete a task, and the associated risks, during the Hazard Identification and Risk Assessment (HIRA) process, to minimize the potential for personal injury.
Apr-2023	MSI	0	Yes	IBEW	Langford	• Reviewed event with employees, highlighted need to be aware of surroundings, even during perceived low-risk activities.
May-2023	Fracture	49.5	Yes	IBEW	Langford	• Purchased shovel pads and piloted new ergonomic equipment to decrease associated risks when performing such tasks.
Apr-2023	Infection	75	Yes	IBEW	Burnaby	• Reviewed event with employees during safety meeting, highlighted importance of wearing proper hand protection (i.e. gloves) for the task.
Jun-2023	MSI	0	Yes	IBEW	Cranbrook	• Developed and distributed Safety Alert across Operations. • Reviewed event during safety meetings, highlighted need for diligence when driving and importance of securing all equipment.
Jun-2023	MSI	15	Yes	IBEW	Vancouver	• Manager contacted fencing contractor to replace meter cage. • Reviewed event during safety meeting, reminded employees to raise a notification about meter cages that are not easily accessible or unsafe.

Month-Year	General Nature of Incident	Total Days Lost	WSBC Claim	Affiliation	Work Location	Measures Taken to Avoid Recurrence
Jun-2023	MSI	6	Yes	IBEW	Richmond	• Reminded employees about the importance of performing MoveSafe, particularly before high-risk tasks or after periods of inactivity.
Jul-2023	MSI	1	Yes	IBEW	Langford	• Engineered transport cage to allow for large diameter butt fusion machine to be loaded on and transported using powered mobile equipment.
Jul-2023	MSI	2	Yes	IBEW	Langley	• Manager ensured driver training included content on entering and exiting a vehicle with three points of contact. • Reviewed event during safety meeting, highlighted importance of maintaining three points of contact when exiting a vehicle.
Jul-2023	MSI	111	Yes	IBEW	Trail	• Encouraged participation in MoveSafe and discussed the importance of stretching throughout the workday.
Aug-2023	MSI	5	Yes	IBEW	Langley	• Reviewed the event during safety meeting and discussed importance of MoveSafe. Highlighted the differences between static and dynamic stretching.
Sep-2023	MSI	0	Yes	IBEW	Kelowna	• Injury Management Specialist delivered presentations to supervisors and employees about managing injuries. • Reviewed event during safety meeting, discussed body positioning when working in congested areas and importance of MoveSafe.
Oct-2023	MSI	2	Yes	IBEW	Kelowna	• Reviewed event during safety meeting, reminded employees to be mindful of repetitive tasks and to take micro breaks and stretch throughout the workday.
Nov-2023	Laceration	0	No	IBEW	Burnaby	• Reviewed event during safety moment, highlighted alternate methods to cut polyethylene and discussed the importance of using cut-resistant gloves.
Dec-2023	Fracture	19	Yes	IBEW	Chilliwack	• Reviewed options for providing stable ground inside excavations. Discussed safety footwear, highlighted the importance of typing up laces, inspecting footwear, and having adequate ankle support. • Injury Prevention Specialist delivered presentation on slip, trip, and fall prevention.
Dec-2023	MSI	0	Yes	IBEW	Burnaby	• Explored options for constant rear view camera in welding truck.

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REFERENCE: EX. B-1 page C-183:

FortisBC has been exploring potential leading indicators but does not yet have a formal, defined indicator to propose for inclusion as an SQI. Instead, FortisBC will continue to examine and develop a leading safety indicator during the term of the Rate Framework and will propose a suitable leading indicator either during the Rate Framework (as part of the Annual Review process) or subsequent to the conclusion of the three-year term of the Framework. FEI and FBC expect that any new leading safety indicator would initially be informational only, as there will likely be a lack of adequate historical information to establish a benchmark or threshold. This approach will allow FEI and FBC to evaluate suitable metrics, propose a suitable metric, and engage in discussions with the BCUC and interveners on whether the selected metric is appropriate for inclusion in the Companies' suite of SQIs.

REQUEST:

9.2 When and how does FortisBC plan to initiate these discussions with interveners?

Response:

FortisBC anticipates that as part of the process in 2027 to assess whether the proposed Rate Framework should be extended (and if so, what components of the Rate Framework should be adjusted), FortisBC would engage with interveners and BCUC staff on the potential new leading indicator for safety. Additionally, FortisBC is open to engaging with interveners on leading and lagging safety indicators during the term of the Rate Framework. This could be done formally through the Annual Reviews (i.e., through IRs and at the Workshops) and/or informally based on the interest of intervener groups.

10.0 TOPIC: ARISING FROM EXHIBIT A-4

REFERENCE: EX. A-4, BCUC IR No 1, IRs 4.x

AND REFERENCE: https://www.theglobeandmail.com/canada/article-vancouver-reverses-its- decision-to-ban-natural-gas-for-heating-cooking/

10.1 Please discuss FEI's expectations of the potential impact of the Vancouver City Council decision to loosen access to new natural gas connections within the City on the issues raised in this series of Information Requests from the Commission.

Response:

It is too early to identify the potential impacts of the Vancouver City Council's decision to allow new residential natural gas connections as the proposed amendments to the City's bylaws have not yet been adopted. At the council meeting referenced in the preamble, council directed staff to draft amendments to the current bylaws to allow for natural gas as an option in new residential construction. These proposed amendments are to be presented to council in November and then voted upon.

10.2 To what extent has the persistence to-date of the City's current restrictive policy already negatively affected FEI's customer additions? When and to what extent does FEI expect that the reversal of the City's restrictive policy would be reflected in customer additions over the term of the proposed rate-setting framework?

Response:

The City of Vancouver's existing policies restricting new gas connections in residential and commercial buildings have negatively impacted FEI's market capture rate for new customer additions. In particular, the market capture rate for new customer additions has dropped from 85 percent in 2019 to 62 percent in 2022.[4]

As discussed in the response to MoveUP IR1 10.1, it is too early to identify the potential impacts of the Vancouver City Council's decision to allow new natural gas connections, as the proposed amendments to the City's bylaws have not yet been adopted.

10.3 What is the impact of provincial and municipal land-use policies and zoning rules to encourage densification of existing urban neighbourhoods on the propensity of

[4] Due to a time lag in the reporting of market capture data, 2022 is the most recent information available.

new and re- developments to attach to the natural gas distribution system? To what extent does FEI expect that these policies and rules will make themselves felt during the term of the proposed rate- setting framework?

Response:

An increase in housing starts driven by provincial and municipal policies, such as those enabling small-scale multi-unit housing and transit-oriented development, could drive an increase in attachments to FEI's gas distribution system, while polices restricting the use of natural gas for heating such as the City of Vancouver's existing bylaws and the provincial Zero Carbon Step Code, could decrease these attachments.

As compliance with provincial and municipal policies will take a few years, the impact of these policies could begin to affect FEI's attachments by the end of the Rate Framework term. In particular, local governments must first update their Official Community Plans (OCP) and zoning bylaws to comply with the new provincial legislation, after which builder/developers will seek approval for their developments permits in accordance with the new OCPs and bylaws.

10.4 To what extent does FEI anticipate that the City of Vancouver "Broadway Plan" will entail new natural gas connections, in view of the changing City policy?

Response:

FEI is aware that the Broadway Plan calls for "electric source equipment wherever possible, including air source heat pumps on rooftops and in parkades". However, as discussed in the response to MoveUP IR1 10.1, the City's bylaws have not yet been adopted so the impact of the proposed amendments on the Broadway Plan is unknown at this time.

REFERENCE: EX. A-4, BCUC IR No 1, IRs 39.x:

REQUEST:

10.5 How should gas utility capital management and depreciation be integrated with resource and transition planning in the context of GHG mitigation policy?

Response:

As discussed on page D-2 of the Application, FEI does not consider it appropriate at this time to accelerate depreciation as a GHG mitigation policy. While there is evidence that the future of

conventional natural gas may be impacted by climate change legislation, the extent that this may change the useful life of FEI's assets remains unknown and it is therefore premature to accelerate depreciation. As noted by Concentric on page 3-4 of Appendix D2-1 to the Application: "As the energy transition continues to evolve, a change in depreciation methodology may or may not be required in the future …". As a result, FEI does not consider it appropriate or practical at this time to attempt to evaluate the possible impacts of accelerated depreciation on FEI's long-term resource planning and capital management. Further, in the recently released provincial energy strategy, Powering Our Future, BC's Clean Energy Strategy,[5] the Province concludes that "[m]aintaining BC's existing gas infrastructure is necessary to ensure BC can deliver clean fuels as production ramps up in the years ahead, in addition to supporting the resiliency of BC's energy system."

With regard to resource planning and gas utility capital management, FEI believes the current processes for long-term resource planning and capital management adequately incorporate considerations for the potential impacts of GHG mitigation policy.

First, with respect to capital management, FEI utilizes its AIP process to actively manage the planning and execution of its capital plan to achieve value for customers and considers the potential impacts of climate policy on future gas demands. For example, as part of the AIP process, given the uncertainty over future gas demand levels driven by climate policy, capacity driven projects have been reviewed to ensure they meet the needs of the shorter-term system demand forecast.

Second, with respect to long term resource planning, as part of FEI's LTGRP, FEI has considered provincial GHG emission reductions and, in its most recent filing, presented a 20-year view of the demand-side resources and supply-side resources identified to meet expected future gas demand, reliability requirements, and provincial GHG emission reduction requirements at the lowest reasonable cost to customers.

10.5.1 Are traditional depreciation studies an adequate mechanism for these purposes? Is there a better way to organize the way these issues are examined?

Response:

FEI considers traditional depreciation studies, which determine the appropriate asset service lives to recover the costs of a utility's capital assets, remain adequate for evaluating the impact of the energy transition on the useful life and depreciation of its assets. Depreciation study industry experts, like Concentric, have established and longstanding knowledge of natural gas distribution

[5] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/community-energy-solutions/powering_our_future_-_bcs_clean_energy_strategy_2024.pdf

assets and are familiar with factors that affect these assets' useful lives. Additionally, depreciation experts are able to provide an industry perspective (i.e., development in other jurisdictions on adoption of accelerated depreciation) to best examine and assess the potential impact of the energy transition and the need for accelerated depreciation for FEI and other utilities.

10.6 To what extent could accelerating the depreciation of FEI assets in anticipation of their accelerated obsolescence or under-utilization due to impacts of climate policy or electrification carry a risk of prophetic self-fulfillment (i.e., of exacerbating these potential impacts and complicating capital transition strategies that could mitigate rate impacts on remaining customers and help maintain the useful lives of the affected assets?)

10.6.1 For example, could the rate impact of accelerating depreciation increase the risk of "death spiral" and/or complicate system transition to the stable delivery of RNG, hydrogen and other fuels?

Response:

Accelerating the depreciation of FEI's assets based on the expectation they will become obsolete faster than expected due to climate policy will increase depreciation expense and therefore increase customer delivery rates. This would negatively impact customer affordability, reduce the competitiveness of natural gas as an energy choice, constrain FEI's ability to invest in the energy transition, and ultimately accelerate reduced demand for natural gas without an alternative reliable energy source available that can absorb the shift in FEI's load. As the pace of the energy transition and its impacts on FEI's operations is uncertain, and to date there have been no indications (as discussed in the FEI 2022 Depreciation Study) that the energy transition is resulting in changes to the useful life of FEI's assets, FEI considers it premature to consider accelerating the depreciation of its assets.