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September 6, 2024

Residential Consumer Intervener Association
1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Michael Vaney, Director

Dear Michael Vaney:

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 Residential Consumer Intervener Association (RCIA) 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 RCIA 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

A. Overview

1. Reference: Exhibit B-1 Application p.A-1

MRP Past Performance

On page A-1 of the Application, FortisBC states:

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

1.1 Please provide tables of allowed return on equity (ROE) compared to the actual ROE earned each year for the period 2014 to 2023 and projected for 2024 for each of FEI and FBC.

Response:

Please refer to Table 1 below for the allowed return on equity (ROE) compared to the actual ROE (post-earnings sharing) for FEI and FBC from 2014 to 2023. As FEI and FBC do not project actual ROE for the current year, the 2024 ROE provided is equal to the Companies' allowed ROEs.

Table 1: FEI and FBC Allowed ROE Compared to Actual ROE (Post-Earnings Sharing) for 2014 to 2023 and 2024 Projected

	FEI			FBC		
	Allowed ROE (a)	Actual ROE (b)	Variance (c) = (b) - (a)	Allowed ROE (d)	Actual ROE (e)	Variance (f) = (e) - (d)
2014	8.75%	9.20%	0.45%	9.15%	9.22%	0.07%
2015	8.75%	9.19%	0.44%	9.15%	9.26%	0.11%
2016	8.75%	9.28%	0.53%	9.15%	9.38%	0.23%
2017	8.75%	9.04%	0.29%	9.15%	9.31%	0.16%
2018	8.75%	8.93%	0.18%	9.15%	9.29%	0.14%
2019	8.75%	8.85%	0.10%	9.15%	9.18%	0.03%
2020	8.75%	8.81%	0.06%	9.15%	9.30%	0.15%
2021	8.75%	8.76%	0.01%	9.15%	9.26%	0.11%
2022	8.75%	8.97%	0.22%	9.15%	9.43%	0.28%
2023	9.65%	9.85%	0.20%	9.65%	9.85%	0.20%
2024P	9.65%	9.65%	0.00%	9.65%	9.65%	0.00%

1.2 Please explain whether and how weather affects the actual ROE earned each year.

Response:

The impact of revenue variances due to weather on FEI's and FBC's current year ROEs is zero. As shown in Table C4-7 of the Application, FEI's revenue variances between forecast and actual, which would include variances due to weather, are either captured in the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account or the Flow-through deferral account, and all of FBC's revenue variances are captured in the Flow-through deferral account. Both the RSAM and Flow-through deferral accounts are recovered from or returned to customers in subsequent years.

2. Reference: Exhibit B-1 Application p.A-2, B-14

Flexible Rate Setting

On page A-2 of the Application, FortisBC states:

> *"A key focus of this Application is on proposing flexible rate setting mechanisms that recognize the uncertainty inherent in the energy transition and that manage its impacts on the provision of affordable, reliable, and resilient service to customers in the face of heightened concern around the impacts of climate change, as well as physical and cyber security risks on BC's energy systems."*

On page B-14 of the Application, FortisBC states:

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

2.1 Please explain whether the rate setting mechanisms proposed in the Application have the flexibility to deal with negative net customer growth. Do the formulas proposed in this Application provide meaningful levels of formula O&M and formula Growth Capital if customer growth is negative?

Response:

While FEI expects the energy transition to continue to have impacts on the rate of customer growth, there is no evidence to suggest that the growth rate of customer additions will fall to zero or become negative during the proposed three-year Rate Framework term.

As explained in the response to BCUC IR1 8.4.1, FEI's and FBC's formula O&M is escalated based on the forecast average customer count, not net customer additions, and as shown in that response, the average customer count for both utilities has been increasing annually. FEI added more customers in 2023 than in the previous years of the Current MRP and there is no evidence to suggest new customer additions will cease completely over the next three years.

Regarding FEI's Growth capital, the formula is based on gross customer additions (i.e., new customer attachments or connections); therefore, by definition, it is not possible to have negative

gross customer additions as the question suggests (the minimum gross customer additions would be zero). As shown in the response to MoveUP IR1 3.1, FEI expects the gross customer additions over the proposed three-year Rate Framework term to continue to decline; however, the expected level of gross customer additions is not significantly different than the level experienced in the past, particularly between 2011 and 2013. FEI considers that its proposed formula Growth capital will provide sufficient funding during the Rate Framework term, with the level of funding being representative of the forecast annual gross customer additions. FEI expects the growth rate of gross customer additions to continue to decline, but does not expect there to be zero gross customer additions in any of the years of the proposed Rate Framework term.

Please also refer to the responses to MoveUP IR1 2.1, 2.2 and 2.5.

B. Rate Setting Framework Considerations

3. Reference: Exhibit B-1 Application p. B-2

Balancing Affordability and Climate Goals

On page B-2 of the Application, FortisBC states:

> *"Echoing this sentiment, the Honourable Josie Osborne, Minister of Energy, Mines and Low Carbon Innovation, emphasizes that affordability should be a cornerstone of British Columbia's energy transition. This commitment to balancing affordability and climate action is reflected in the Premier's mandate letter to Minister Osborne of January 15, 2024, which directs the Minister to "work with the BC Utilities Commission to identify an appropriate role for the Commission in supporting B.C.'s clean energy transition, in alignment with the province's climate goals to achieve net zero by 2050 and affordability objectives". [underlining added]"*

3.1 Please explain how FortisBC intends to balance affordability and climate action, if the goal is to achieve net zero GHG emissions by 2050, which is a specific, objective measure while affordability is a relative measure. For example, what will FortisBC balance with affordability: the year of achievement of net zero? The pace of achieving net zero? Is affordability a function of the choices made to achieve net zero, or is there flexibility in the achievement of net zero?

Response:

Balancing affordability and responding to the energy transition to meet GHG emissions targets are not straightforward trade-offs, and there are other factors that must be considered such as reliability and resiliency.

As RCIA states in the question, affordability is a relative measure; it is defined differently by different customer segments, so there is no specific level of increase that can be used to measure affordability or affordable rates. The energy transition is expected to continue to put upward pressure on rates for both FEI and FBC. FortisBC considers that affordability and affordable rates should be viewed through the lens of the Companies' ability to decarbonize the system and transition to low carbon fuels at the lowest reasonable cost, while also maintaining safe, reliable and resilient service.

Achieving net zero GHG emissions is a long-term goal; therefore, the balance between affordability and sustainability, as well as reliability and resiliency, requires a long-term approach. There are many factors outside of FortisBC's control, such as policy requirements or the future costs of alternative energy sources and associated technologies, among other things, that will shape the long-term energy future.

FortisBC's Clean Growth Pathway, as presented in FBC's 2021 Long-Term Electric Resource Plan (LTERP) and FEI's 2022 Long-Term Gas Resource Plan (LTGRP), outlines the Companies'

plans to transition to a lower carbon future, reflecting a wide range of considerations that must be balanced. FortisBC's proposed Rate Framework consider the complexities of transitioning to a low carbon future, as discussed in the Companies' long-term resource plans.

As explained in the response to BCUC Panel Supplemental IR 1, the energy transition is having, and will continue to have, an impact on rates. The proposed Rate Framework is designed to allow the cost implications of the energy transition to be incorporated into FortisBC's rates while managing the resulting rate impacts in an affordable manner for customers.

Given the level of uncertainty in how net zero GHG emissions will be achieved (including the degree to which emissions reductions versus the removal of carbon from the atmosphere are required to achieve net zero), and the degree to which various decarbonization initiatives will ultimately support this goal, FortisBC has designed the proposed Rate Framework to maintain flexibility. Specifically, the proposed Rate Framework incorporates mechanisms designed to enable FortisBC to invest in clean energy and emissions reduction activities (e.g., the proposed flow-through treatment of Clean Growth Initiatives) while also providing incentives to find efficiencies and cost savings in other areas of the Companies' operations (e.g., the formulaic approach to O&M and Growth capital for FEI which includes a productivity or "X" factor), with an overall focus on FortisBC's ability to provide safe, reliable and resilient service to customers.

4. Reference: Exhibit B-1 Application p. B-4

Double Carbon Taxation

On page B-4 of the Application, FortisBC states:

> *"One particular risk for FEI is that the GHGRS, as discussed in Section B1.3.1, could effectively introduce an indirect carbon pricing mechanism. If the carbon tax is also added to gas customers' bills, then they will effectively pay a double carbon charge with both the GHGRS and carbon tax."*

4.1 Please explain how the GHGRS would potentially introduce indirect carbon pricing.

Response:

The cost of the carbon tax is currently borne by FEI's customers. If the GHGRS were to proceed, the direct cost of the carbon tax and the indirect costs (not shown explicitly on customers' bills) that are required to be spent to comply with the GHGRS emissions cap would both be borne by FEI's customers, resulting in customers effectively paying duplicative emissions charges.

5. Reference: Exhibit B-1 Application p. B-6

Building Codes and Demand Forecasting

On page B-6 of the Application, FortisBC states:

> *"For FEI and FBC, evolving building codes are expected to place some downward pressure on building energy demand as building envelope and mechanical system efficiency increases, helping to offset demand increases due to population growth and fuel switching"*

5.1 Please explain how the BC Energy Step Code and the Zero Carbon step Code are incorporated into FEI's and FBC's demand forecasting.

Response:

The impact of enacted policies and regulations, such as the BC Energy Step Code, Zero Carbon Step Code and DSM Regulation, are reflected and inherent in the actual historical data used to prepare the short-term single-year forecast for rate-setting purposes. FEI and FBC do not make explicit adjustments to the single-year short-term demand forecast to account for the future impacts of policies or regulations. For further discussion on why explicit adjustments due to the future impacts of policies, regulations and other drivers are not incorporated into the short-term single-year forecasts, please refer to the response to BCUC IR1 27.2.

However, FEI and FBC do explicitly account for building codes, the DSM Regulation and other policies in their long-term forecasts for resource planning purposes. Please refer to the response to BCUC IR1 27.4 for a discussion of the difference between the short-term forecasts used for rate-setting purposes and the long-term (e.g., 20-year) forecasts used for resource planning purposes, including how building codes and other policies are reflected in FortisBC's long-term forecasting. FortisBC notes that although BCUC IR1 27.4 focuses on the forecasting method for FBC, the distinction between a short-term rate-setting forecast and a long-term resource planning forecast is the same for both FEI and FBC.

5.2 Please explain how the DSM Regulation is incorporated into FEI's and FBC's demand forecasting.

Response:

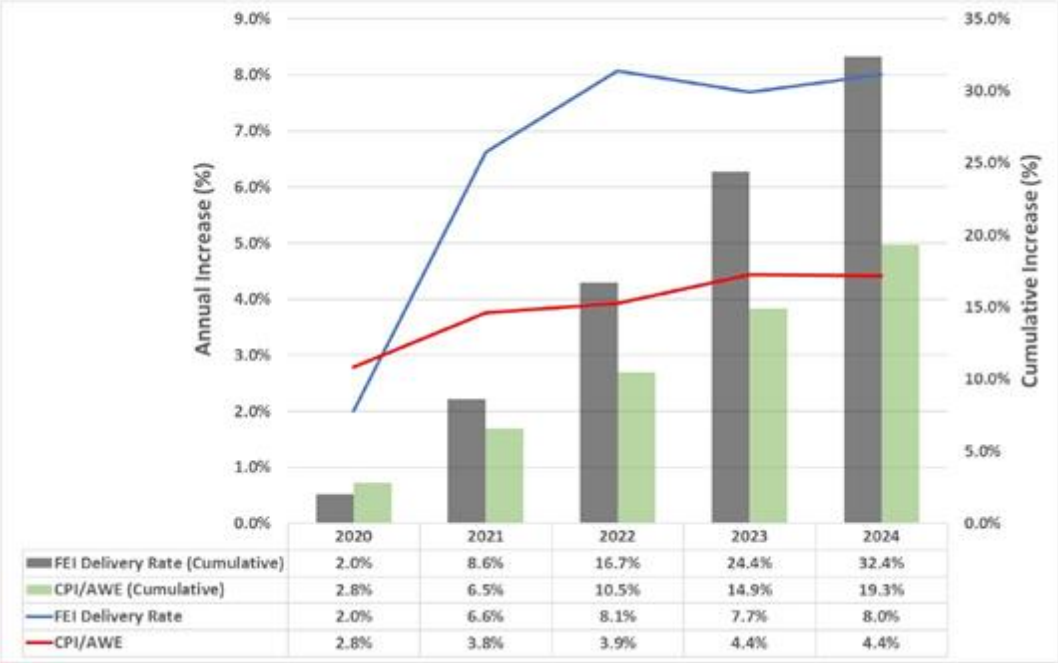
Please refer to the response to RCIA IR1 5.1.

6. Reference: Exhibit B-1 Application p.B-19; 2022 Annual Rates Application Exhibit B-2 Application p.11; 2023 Annual Rates Application Exhibit B-2 Application p.12; 2024 Annual Rates Application Exhibit B-2 Application p.9

Evaluation of Current MRP – Inflation Factors

FortisBC shows the FEI delivery rate changes through the term of the Current MRP in Figure B2-1, including the annual CPI/AWE inflation factors:

Figure B2-1: FEI Delivery Rate Changes During the Current MRP Term



	2020	2021	2022	2023	2024
FEI Delivery Rate (Cumulative)	2.0%	8.6%	16.7%	24.4%	32.4%
CPI/AWE (Cumulative)	2.8%	6.5%	10.5%	14.9%	19.3%
FEI Delivery Rate	2.0%	6.6%	8.1%	7.7%	8.0%
CPI/AWE	2.8%	3.8%	3.9%	4.4%	4.4%

In the 2022 Annual Rates Application on page 11, FEI stated:

> *"In summary, the Net Inflation Factor for 2022 is 3.324 percent."*

In the 2023 Annual Rates Application on page 12, FEI stated:

> *"As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE BC data. Applying the actual 2021 labour weighting of 51 percent, the calculation of the 2023 I- Factor is (4.940 percent x 49 percent) + (4.235 percent x 51 percent) = 4.580 percent."*

In the 2024 Annual Rates Application on page 9, FEI stated:

> *"For 2024, the formula incorporates a net inflation factor of 3.854 percent…"*

6.1 Please explain why the inflation factors in the prior Annual Rate Applications differ from the inflation factors shown in Figure B2-1.

Response:

The inflation factors provided in Figure B2-1 of the Application are the Approved CPI/AWE (i.e., I-Factors) from 2020 to 2024, whereas the values from the Annual Review for 2022 Delivery Rates (i.e., 3.324 percent) and Annual Review for 2024 Delivery Rates (3.854 percent) referenced in the preamble above are the *net* inflation factors, which are the approved CPI/AWE minus the 0.5 percent productivity factor (i.e., I – X Factor).

FEI also notes that due to the time lag of Statistics Canada releasing the AWE-BC, the values for the months of May and June are typically not available when FEI files the Annual Review each year. As such, placeholders are typically used in the Annual Reviews and are replaced with actuals either as part of the Evidentiary Update or in the Compliance Filing subsequent to the BCUC Decision. The 2023 CPI/AWE of 4.580 percent referenced in the preamble above was updated to 4.432 percent as part of the Evidentiary Update to FEI's Annual Review.[1] Additionally, and as explained in previous Annual Reviews,[2] Statistics Canada periodically revises their AWE-BC results, which can result in changes from year-to-year, as FortisBC uses the most current set of AWE-BC results in each year's Annual Review filing.

Please refer to Table 1 below which shows FEI's approved CPI/AWE values (which have been rounded to a single decimal place in Figure B2-1) and the approved net inflation factors from 2020 to 2024 after subtracting for the productivity factor. FEI also notes the approved CPI/AWE values shown in Table 1 below include the actual AWE-BC data updated in the Evidentiary Update/Compliance Filing of each year's Annual Review.

Table 1: FEI Approved Formula Inflation Factors (2020 to 2024)

	2020	2021	2022	2023	2024
CPI/AWE	2.790%	3.753%	3.920%	4.432%	4.414%
Productivity Factor	-0.500%	-0.500%	-0.500%	-0.500%	-0.500%
Net Inflation Factor	2.290%	3.253%	3.420%	3.932%	3.914%

[1] Exhibit B-13, FEI's Annual Review for 2023 Delivery Rates, Evidentiary Update, Section 3, October 24, 2022.

[2] E.g., see the explanation provided in the response to BCOAPO IR1 3.3.1 in the FBC Annual Review for 2024 Rates proceeding.

7. Reference: Exhibit B-1 Application p. B-45, 46

Term

On page B-45 of the Application, FortisBC states:

> *"FortisBC is proposing a three-year term for its Rate Framework, with an option to extend beyond three years subject to a review of the operating environment at that time."*

7.1 Please explain whether exercising the option to extend the Rate Framework beyond 2027 would necessitate a re-examination of any of the components of the Rate Framework as set out in Section 1.3.1 and Table A1-1.

Response:

FortisBC proposes to review the elements of the Rate Framework in 2027 and, in consideration of any changes in the external policy or operating environment at that time, determine whether an application for extension of the Rate Framework (for one or both utilities) is reasonable and, if so, whether any elements of the Rate Framework should be changed or adjusted. FortisBC also notes that it will consult with BCUC staff and interveners at that time to help inform its proposal, which will be subject to review and BCUC approval.

For example, FortisBC explained in Section C6.3.1 of the Application that it will continue to examine and develop a leading indicator of safety. Introducing a leading indicator of safety could occur as part of the process in 2027 to extend the Rate Framework. Similarly, changes or additions to the proposed energy transition informational indicators could be reviewed during the same process.

Another example is in relation to the Advanced Metering Infrastructure (AMI) project. As part of the Rate Framework Application, FEI has proposed to treat the O&M items listed in Table C2-2 as flow-through expenses during implementation of the AMI project in order to recognize that there may be uncertainties in the deployment schedule which could change the timing of expected O&M savings. However, once deployed, FEI would consider whether moving ongoing O&M back into the formula is appropriate, consistent with how those categories of O&M have historically been treated in FEI's multi-year rate frameworks. Similarly, FEI has proposed in the Application to change the Meter Reading Completion SQI to be an informational indicator during the term of the Rate Framework and to assess the metric and determine if it should be re-instated as a measured SQI with adjusted benchmarks and thresholds at the conclusion of the three-year term. These topics could be included in a review of the Rate Framework in 2027.

Additionally, since FEI and FBC are only seeking approval of three-year forecasts for regular Sustainment, Growth (for FBC only) and Other capital as part of this Application, FEI and FBC would need to provide forecasts for any years of the Rate Framework extension.

The process to determine whether the Rate Framework should be extended and if so, what should be included in an application, could take various procedural forms. However, FortisBC anticipates that it would undertake informal consultation with the BCUC staff and interveners prior to filing a request to extend the Rate Framework. Upon initiation of the regulatory process, the BCUC would determine, based on responses to IRs and submissions from parties, whether the Rate Framework should be extended and, if so, the scope of the Rate Framework components that should be reviewed and potentially adjusted through a further regulatory review process.

7.2 If yes, please provide details on what, specifically, Fortis would plan to re- examine.

Response:

Please refer to the response to RCIA IR1 7.1.

8. Reference: Exhibit B-1 Application p. B-47, Exhibit B2-1, p. 62-63 Table B2-1 Efficiency Carryover Mechanism

On page B-47 of the Application, FortisBC states:

> *"Given the limited time frame for the proposed Rate Framework (three years), FortisBC does not consider it necessary to include an efficiency carryover mechanism (ECM) in the proposed Rate Framework."*

8.1 Considering the ECM was intended to operate only in the final three years of the Current MRP, why is the shorter term of the Proposed MRP a reason to eliminate the ECM?

Response

The Companies will be continuing to seek efficiencies that result in savings; however, given that no approved ECM mechanisms have been triggered to date, FortisBC requires time to consider whether an ECM provides sufficient benefits, and to design an ECM that is simple to understand and that would more effectively incent investments in efficiencies in the context of the energy transition. Given the shorter term of the Rate Framework, FortisBC did not consider it necessary to propose an ECM. The focus of the Companies in the upcoming three years will be on investing in activities that support the clean energy transition, maintaining safe, reliable and resilient service, and managing rate impacts and affordability for customers. As noted on page C-20 of the Application, FortisBC will continue to evaluate the design of any future ECM and may propose to re-instate an ECM in the future.

9. Reference: Exhibit B-1 Application p.C-28

Customer Disconnections

On page C-28 of the Application, FortisBC states:

> *"Operations O&M: This is the cost for activities completed by field crews that are impacted by the AMI project, specifically meter trouble calls, meter reads, meter identifications, disconnects, unlocks, cathodic protection data gathering, and odour measurement."*

9.1 Please confirm whether customer disconnections are included in formula O&M.

Response:

Confirmed. The actual costs related to disconnections are recorded within the spending envelope provided by the approved formula O&M. As there are various reasons for disconnections (which include safety, seasonality, vacancies, arrears, unauthorized use, and customer conversions) and associated costs to perform these services, an increasing number of customer disconnections may increase the actual formula O&M spend that is required, all else equal. However, other customer-related costs may also decrease if there are fewer customers.

As explained in the response to BCUC IR1 8.4.1, FEI's and FBC's formula O&M is escalated based on the forecast average customer count, not net customer additions. Therefore, if FEI experiences an increasing number of disconnections or decreasing customer counts (i.e., "negative customer additions"), then the forecast average customer count would be reduced from the prior year's actual average customer count and would consequently decrease FEI's formula O&M spending envelope. However, while FEI expects that the growth rate in new customer connections will continue to decline, there is no indication that the total average number of customers will be declining in the upcoming three years.

FEI also notes that the preamble, which is taken from page C-28 of the Application, is in reference to FEI's proposal to reclassify certain costs related to the approved AMI project from formula O&M to forecast (flow-through) O&M. The AMI project would have no impact on FEI's average customer count (i.e., the disconnection from existing diaphragm meters and reconnection with new AMI meters at the same time would not impact the average customer count). The purpose of the reclassification of these costs is to ensure the proper tracking and reporting of the annual costs and savings, as contemplated in the response to BCUC IR1 20.2 in the AMI Project CPCN proceeding (provided on page C-27 of the Application).

9.2 Please explain how negative customer additions affect formula O&M.

Response:

Please refer to the response to RCIA IR1 9.1.

C. Proposed Rate Setting Framework – Components of the Rate Framework

10. Reference: Exhibit B-1 BCUC Application, p.C-4-C-5

Inflation (I) Factor

Table C1-2: History of Labour and Non-labour Split for FEI and FBC

	FEI		FBC	
	Labour	Non-Labour	Labour	Non-Labour
2019	52%	48%	62%	38%
2020	52%	48%	62%	38%
2021	51%	49%	63%	37%
2022	51%	49%	60%	40%
2023	49%	51%	57%	43%
Average	51%	49%	61%	39%

On page C-4 of the Application, FortisBC states:

> "In proposing the weightings, FortisBC reviewed the recent history (2019 to 2023) of the labour and non-labour splits that were approved during the term of the Current MRP as shown in Table C1-2 above."

10.1 Please update the table to provide the labour and non-labour splits for the years 2014 through 2018.

Response:

Please refer to the response to CEC IR1 6.1.

10.2 Please explain whether there is a measurable trend in the movement of labour and non-labour splits over time.

Response:

Please refer to the response to RCIA IR1 10.1.

11. Reference: Exhibit A-4 BCUC IR1 5.1

Term

BCUC Staff IR1 5.1 requests:

> *"Please discuss the advantages and disadvantages of a Rate Framework term that is shorter than three years given both the uncertainty in FortisBC's current operating environment due to the energy transition and the enabling legislation for the GHGRS that may be introduced to the provincial legislature in 2024."*

11.1 Please discuss the advantages and disadvantages of a Rate Framework term that is longer than three years.

If the BCUC orders that the MRP be extended for a total term of 4 or 5 years, please explain what changes FortisBC would need to make to the MRP and how such changes could procedurally be made.

Response:

Please refer to the response to ICG IR1 3.1. If the BCUC approved a term of 4 or 5 years for the Rate Framework as part of the decision on this Application, FortisBC would need to review the determinations made in the decision holistically to assess whether a longer term was reasonable. However, in terms of the mechanisms proposed in the Application, they could remain in place beyond three years, and conceptually, the only components that would not be established in the decision on this Application would be the regular Sustainment, Growth (for FBC only) and Other capital forecasts for 2028 and 2029. As explained in the response to ICG IR1 3.1, FortisBC would not propose to establish those forecasts as part of the Rate Framework. Instead, consistent with the approach in the Current MRP, FortisBC would propose to provide these forecasts in the Annual Review for 2027 Rates applications.

Please also refer to the response to RCIA IR1 7.1 for a discussion of how this approach could occur at the conclusion of the three-year term.

12. Reference: Exhibit B-2 Application p. B-29, B-30, C-8, C-10

Productivity X-Factor

On page C-8 of the Application, FortisBC states:

> *"… Dr. Kaufmann recommends a 0.10 percent stretch factor which, when added to the industry O&M PFP growth of 0.28 percent, results in a 0.38 percent X-Factor recommendation for FEI."*

On page C-10 of the Application, FortisBC states:

> *"… Dr. Kaufmann recommends a zero percent stretch factor which, when added to the industry O&M PFP growth of 0.20 percent, results in a 0.20 percent X-Factor recommendation for FBC.*
>
> *…*
>
> *FortisBC is proposing to eliminate the 0.75 discount factor currently applied to the growth factor for the O&M formulas."*

12.1 Please reproduce figures B2-8 and B2-9 if the productivity factors proposed for the MRP on page C-6 and C-10 had been in place for the 2020-2024 MRP, including no discount factor applied to the number of customers.

Response:

Please refer to Tables 1 and 2 below for a version of Table B2-8 and Table B2-9 from the Application, respectively, using the proposed X-Factor of 0.38 percent for FEI, the proposed X-Factor of 0.20 percent for FBC, and the elimination of the 0.75 discount factor currently applied to the growth factor for FEI's and FBC's O&M formulas.

Table 1: FEI Application Table B2-8 with X-Factor of 0.38 percent and No Discount Factor

Year	Actual (a)	Formula with 0.38% PIF and No Discount Factor (b)	Savings above the Formula (c=b-a)	Formula without 0.38% PIF (d)	Savings related to 0.38% PIF (e = d-b)	Total Savings to customer w/ Sharing (f = 0.5*c + e)
2020	$ 259.5	$ 262.8	$ 3.3	$ 263.9	$ 1.1	$ 2.8
2021	268.3	274.9	6.6	276.0	1.1	4.4
2022	281.7	288.8	7.0	290.9	2.1	5.6
2023	295.0	303.4	8.4	306.6	3.2	7.4
2024P	309.6	317.8	8.3	323.3	5.4	9.6
Total			**$ 33.6**		**$ 13.0**	**$ 29.8**

Table 2: FBC Application Table B2-9 with X-Factor of 0.20 percent and No Discount Factor

Year	Actual (a)	Formula with 0.20% PIF and No Discount Factor (b)	Savings above the Formula (c=b-a)	Formula without 0.20% PIF (d)	Savings related to 0.20% PIF (e = d-b)	Total Savings to customer w/ Sharing (f = 0.5*c + e)
2020	$ 58.2	$ 60.2	$ 1.9	$ 60.3	$ 0.1	$ 1.1
2021	58.9	62.9	4.0	63.4	0.4	2.5
2022	63.6	67.5	3.9	68.1	0.6	2.5
2023	66.1	72.3	6.2	73.1	0.8	3.9
2024P	70.8	75.4	4.5	76.3	0.9	3.2
Total			**$ 20.7**		**$ 2.8**	**$ 13.1**

12.2 Please provide tables of the allowed ROE and what the ROE would have been for FEI and FBC had the productivity factors proposed for the MRP on page C-6 and C-10 had been in place for each year of the 2020- 2024 MRP.

Response:

It is not possible to provide the requested hypothetical scenario. If FEI's and FBC's proposed productivity factors for the Rate Framework had been in place for each year of the Current MRP, then this would presumably have been reflective of industry wide productivity and FEI's and FBC's actual costs and revenues may have been different; therefore, it cannot be known what FEI's and FBC's ROEs would have been in this scenario.

However, to be responsive, and assuming all else equal (i.e., FEI's and FBC's actual results are unchanged), please refer to Table 1 below for the difference between FEI's and FBC's actual ROE (after-sharing) from 2020 to 2023 under the Current MRP and what the ROE (after-sharing) would have been if the formula O&M from 2020 to 2024 was based on the proposed productivity factors of 0.38 percent for FEI and 0.20 percent for FBC, as well as the removal of the 0.75 discount factor on the growth factor (as shown in the response to RCIA IR1 12.1). As FEI and FBC do not project actual ROE for the current year, the 2024 Projected ROE is equal to the Companies' allowed ROEs.

As shown in the table below, and all else equal, the increased O&M savings due to the proposed change to the productivity factors and the removal of the discount factor would lead to a small increase in the actual ROE from the actual ROE achieved from 2020 to 2023.

Table 1: FEI's and FBC's Allowed ROEs, Actual ROEs (After-Sharing), and ROEs (After-Sharing) under Proposed Productivity Factors without Discount Factor from 2020 to 2023 and 2024 Projected

	FEI				FBC			
	Allowed ROE (a)	Actual / Projected ROE (After Sharing) (b)	ROE with 0.38% PIF and No Discount Factor (After Sharing) (c)	Difference (d) = (c) - (b)	Allowed ROE (a)	Actual / Projected ROE (After Sharing) (b)	ROE with 0.38% PIF and No Discount Factor (After Sharing) (c)	Difference (d) = (c) - (b)
2020	8.75%	8.81%	8.83%	0.02%	9.15%	9.30%	9.32%	0.02%
2021	8.75%	8.76%	8.80%	0.04%	9.15%	9.26%	9.29%	0.03%
2022	8.75%	8.97%	9.03%	0.06%	9.15%	9.43%	9.47%	0.05%
2023	9.65%	9.85%	9.91%	0.06%	9.65%	9.85%	9.92%	0.07%
2024P	9.65%	9.65%	9.65%	0.00%	9.65%	9.65%	9.65%	0.00%

BCUC IR1 7.7 requests:

> "Please explain why Dr. Kaufmann's productivity studies focused on US utilities as the comparators to FEI and FBC and why no Canadian utilities were included in the studies as compared to what was done for the benchmarking analysis previously provided by FortisBC in the Current MRP Application proceeding. As part of this response, please discuss the advantages and disadvantages of applying only US data to FEI's and FBC's operations."

On page C-7 of the Application, FortisBC provides Table C1-3:

Table C1-3: O&M PFP Trend for US Natural Gas Distributors 2007-2022

Sample	Period	Customer Growth	O&M Growth	Industry Input Price	O&M Quantity Growth	O&M PFP Growth
54 US NG distributors (excluding gas cost)	2007-2022	0.67%	2.98%	2.59%	0.39%	0.28%

12.3 Please confirm whether FortisBC can prepare a version of Table C1-3 using data from only Canadian gas distributors. If so, please provide.

Response:

The following response was provided by Dr. Kaufmann:

Due to the lack of uniform and standardized data sets for Canadian electric and gas utilities, it is not possible to estimate long-run O&M PFP trends for the Canadian gas distribution or electricity distribution industries, similar to Table C1-3 and Table C1-5.

The following response was prepared by FortisBC:

The applicability of US data for calculating the industry productivity trends for Canadian utilities has been reviewed by various Canadian regulators in the past. For instance, in its first generation PBR Decision, the Alberta Utilities Commission (AUC) concluded that considering the lack of a centralized data set in Canada and given the overall similarities between the two jurisdictions, the use of a US data set is acceptable:[3]

> The Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. As NERA and PEG pointed out, unlike in the United States, there is no Canadian central repository of public data due to the lack of standardized accounting across provinces with respect to utility operating reports. Because of this data problem, regulators in Canada have used U.S. data. For example, the Ontario Energy Board, in several decisions, used U.S. data in establishing its PBR plans.
>
> Mindful of the existing Canadian data limitations, the Commission agrees with NERA, the CCA, the ATCO companies and EPCOR that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.

FortisBC also notes that the BCUC's approved X-Factor in its 2014-2019 PBR Decision was based on average industry productivity growth in the US.

12.4 Please confirm whether FortisBC can prepare a version of Table C1-5 using data from only Canadian electricity distributors. If so, please provide.

Response:

The following response was provided by Dr. Kaufmann:

Please refer to the response to RCIA IR1 12.3.

[3] AUC Decision 2012-237; Para 341-342.

13. Reference: Exhibit B-1 Application p. C-18

Amount Eligible for Exogenous Factor Treatment

Table C1-8: Summary of Remediation Costs and Insurance Proceeds Received

Items	2021 to 2022	2023	2024
	costs incurred ($)	*recovered with insurance ($)*	*exogenous treatment ($)*
O&M	1,641,509	(1,576,242)	65,267
Capital	1,266,012	(1,262,947)	3,064
Bill Credits	826,135	(173,924)	n/a
Total	3,733,656	(3,013,113)	68,331
Deductible		1,000,000	1,000,000
Net insurance proceeds		(2,013,113)	1,068,331

On page C-18 of the Application FortisBC states:

> *"As shown in Table C1-8 above, $3.013 million of the total incremental costs of $3.734 million were recovered, with a remaining unrecovered balance, excluding the bill credits,59 of $0.068 million. Additionally, FEI had a $1 million deductible on this insurance claim that was not recovered."*

13.1 Please explain whether FEI's insurance had a $1 million deductible throughout the Current MRP (2020 – 2024).

Response:

FEI is insured under Fortis Inc.'s group insurance policy. The group insurance program coverage and retention (or deductible limits) amounts have been the same through the Current MRP term, which include a $1 million deductible for property damage related to flooding.

14. Reference: Exhibit B-1 Application p. C-19, Lines 6-9

Earnings Sharing Mechanism

On page C-19 of the Application FortisBC states:

> *"FortisBC is proposing to continue the symmetrical 50/50 earnings sharing mechanism (ESM) under the Rate Framework. An ESM is a regulatory tool in a rate-setting plan that is designed to enhance the alignment between customer and company interests and share the risks and benefits of the plan."*

14.1 Please explain the impact on the alignment between customer and company interests of an asymmetric Earnings Sharing Mechanism whereby the customer's share of ROE variance above allowed is larger than the customer's share of ROE variance below allowed.

Response:

FortisBC considers that a 50/50 earnings sharing mechanism, which includes variances both above and below the allowed ROE, creates a balance between the Companies' and customers' interests and provides an appropriate incentive for FortisBC to seek savings throughout the term of the Rate Framework. This same mechanism was used during the Current MRP and resulted in savings that were shared equally between the customer and shareholder, and FortisBC does not see a reason to deviate from that mechanism.

Shifting a portion of the sharing percentage where the customer receives a greater portion of the favourable variance (over earning) than the unfavourable variance (under earning) would reduce the incentive properties of the Rate Framework and would be unfair and unbalanced, as it would restrict the potential upside of over earnings that result from savings created by the Companies and subject the Companies to a higher risk for any potential under earnings. Therefore, all else equal, this asymmetrical ESM would increase the business risk of the Companies, requiring a higher allowed ROE.

Further, as shown in Table B2-10 of the Application, the review of asymmetric ESMs in other jurisdictions indicates that the higher risk of under earning in asymmetric ESMs is balanced by the higher potential for over earnings through either deadbands (where the utility does not share any or a smaller share of the over earnings) and/or lower sharing percentages.

However, as discussed in the Application, FEI continues to believe that symmetrical 50/50 sharing mechanism provides the appropriate level of alignment between customer and shareholder interests, both in terms of risks and benefits, and avoids unfair outcomes for the Companies and customers.

15. Reference: Exhibit B-1 Application p.C-104

FBC Capital Expenditures

On Page C-104 of the Application, FBC states:

Table C3-27: FBC Approved and Forecast Regular Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Growth Capital	30,072	24,568	41,349	45,035	46,357
Sustainment Capital	44,710	51,652	75,664	72,116	71,310
Other Capital	17,658	17,213	25,070	24,922	22,699
Total Regular Capital (Gross)	**92,440**	**93,434**	**142,082**	**142,074**	**140,365**

15.1 Please provide further justification to the sudden step change increase observed in 2025?

Response:

Each component of FBC's regular capital forecasts for 2025 are described in detail in Sections C3.4.1 (Growth capital), C3.4.2 (Sustainment capital) and C3.4.3 (Other capital) of the Application. Please refer to those sections for further details and breakdowns of each category of expenditure.

For example, and as shown in Table C3-29 on page C-105, the largest driver of the increase in Growth capital in 2025 is the forecast number of Transmission Growth capital projects, which are further broken down in Table C3-30 of the Application. Please also refer to the response to BCUC IR1 23.2 for additional details on the Transmission Growth projects.

Regarding Sustainment capital, as shown in Table C3-33 on page C-110, the largest drivers of the forecast increase in 2025 are Generation and Stations Sustainment. Please refer to the response to BCUC IR1 24.6 for details on FBC's approach to station condition assessments, which FBC uses to determine the required Station upgrades/replacements each year.

Finally, and as explained in Section C3.4.3, the main drivers of the increase in Other capital are increases in Vehicles and Equipment. As explained on page C-131 of the Application, over the next few years, FBC has a substantial capital replacement requirement based on replacement triggers identified by age, engine hours and utilization to maintain safe and reliable vehicles and equipment able to respond to customer calls and provide emergency response. FBC plans to replace 63, 24 and 35 vehicles in 2025, 2026 and 2027, respectively. These replacements encompass light-duty, medium-duty and heavy-duty trucks and vans, trailers, and other equipment.

16. Reference: Exhibit B-1 Application p.C-117

Stations Sustainment Capital

On Page C-117 of the Application, FBC states:

Table C3-36: FBC Approved and Forecast Stations Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Station Urgent Repairs	617	653	680	759	701
Station Assessment/Minor Planned Projects	1,196	1,059	1,454	1,498	1,549
Spare Parts	-	-	1,940	3,484	8,164
Station Sustainment Programs	4,485	3,796	7,354	6,743	6,859
Station Upgrade/Replacement Projects	543	2,701	9,060	11,143	7,509
Total Station Sustainment	**6,841**	**8,209**	**20,486**	**23,627**	**24,783**

16.1 How does FBC forecast the new Spare Parts Program when there is no past benchmarking approvals to forecast upon?

Response:

FBC's current forecast for Spare Parts is based on the findings of an analysis conducted in accordance with TPL-001-04, which identify five distinct pieces of equipment required as spares. Please refer to the response to BCUC IR1 24.3 for further details. Manufacturer pricing was used to forecast the expenditures.

16.2 Please justify the sharp increase in spare parts forecasted in 2026 and 2027?

Response:

The increase in forecast expenditures for the Spare Parts program is due to the timing of compliance for the TPL-001-4 standard and FBC's estimate of the schedule of payments based on the future contract with the manufacturer. While FBC is unable to forecast the exact timing of milestone payments for the equipment until the Purchase Orders are issued, FBC has based the forecasts for 2025 through 2027 on the typical sequence of milestone payments, which is 10 percent in the first year, 20 percent in the second year, and the remaining 70 percent in the third year.

17. Reference: Exhibit B-1 Application p.C-119

Spare Parts

On Page C-119 of the Application, FBC states:

> *"FBC is planning to purchase the following equipment as spares during the Rate Framework term:*
>
> - 500/230 kV, 250 MVA transformer;
> - 230/161/138/63 kV, 200 MVA transformer;
> - 245 kV, 2000 A circuit breaker;
> - 145 kV, 30 MVAR capacitor bank; and
> - 145 kV, 2000 A Point-On-Wave (POW) circuit breaker."

17.1 How many equipment spares has FBC determined are required to comply with TPL-001-4?

Response:

The list provided on page C-119 of the Application (as reproduced in the preamble) represents all of the equipment spares that FBC has identified as being required to comply with TPL-001-4 at this time. For further clarity, each bullet point on page C-119 of the Application represents one unit of equipment (i.e., five pieces of equipment in total).

17.2 How is FBC dealing with long lead time inventory for their spares, and how does this influence spare part quantities?

Response:

To deal with long lead time inventory for spare equipment, FBC is procuring the additional equipment identified above and procuring equipment earlier to account for the expected manufacturer delivery timelines. For example, as explained in the response to BCUC IR1 24.4, the current delivery time estimates from power transformer manufacturers are approximately three years, which means the 500/230 kV, 250 MVA transformer needs to be purchased during the proposed term of the Rate Framework to ensure it is delivered by 2029.

17.3 How many of the listed equipment have failed in the past 5 years?

Response:

None of the above listed equipment has failed within the past five years; however, TPL-001-4 does not allow analyses that includes consideration of equipment condition, equipment age, or statistical outage probabilities. Rather, TPL-001-4 requires studies to be completed considering that it is possible that each piece of equipment or element can experience an outage and if unacceptable system responses occur, corrective actions must be undertaken to prevent or mitigate the unacceptable impact to the electrical system. Please also refer to the response to BCUC IR1 24.3.

17.4 What is the standard lifetime for the above-mentioned equipment?

Response:

The table below presents the manufacturer standard lifetime and FBC asset life expectancy for the requested spare equipment.

Spare Part Description	Manufacturer Standard Lifetime	FBC Asset Life Expectancy[1]
500/230 kV, 250 MVA Transformer	20.5 years (minimum)[2,3]	40-45 years
230/161/138/63 kV, 200 MVA Transformer		40-60 years
245 kV, 2000 A Circuit Breaker	30 years (minimum)[4]	40-45 years
145 kV, 30 MVAR Capacitor Bank	10-years (continuous operation)[5]	25-30 years
145 kV, 2000 A Point-On-Wave (POW) Circuit Breaker	30 years (minimum)[4]	25-30 years

Notes to Table:

[1] *The life expectancy of equipment listed is based on FBC's in-service equipment experiences. Life expectancy can vary based on several factors, including the equipment type, storage/installation conditions, loading, operating conditions, and maintenance.*

[2] *IEEE. (2013) IEEE Standard for General Requirements for Liquid Immersed Distribution, Power, and Regulating Transformers Std. C57.12.00-2015.*

[3] *Assumes transformers is used and loaded under the conditions set by the IEEE C57.12.00-2015.*

[4] *Mitsubishi Electric (2020). 145kV SF6 Gas Circuit Breaker Brochure. USA.*

[5] *Schneider Electric (2014). What is the Expected Lifetime of Varplus Capacitors?*

18. Reference: Exhibit B-1 Application p. C-122

Distribution Sustainment Capital

On Page C-122 of the Application, FBC states:

Table C3-38: FBC Approved and Forecast Distribution Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Distribution Line Condition Assessment	1,730	1,841	1,684	1,543	1,850
Distribution Line Rehabilitation	3,498	3,268	4,728	4,448	5,154
Distribution Line Rebuilds	2,563	1,781	5,299	5,707	3,423
Secondary Network and Transformer Connectivity	-	-	264	264	265
Distribution Urgent Repairs	2,839	2,859	3,376	3,122	3,388
Small Planned Capital	952	842	929	937	1,120
Forced Upgrades and Line Moves	1,158	1,281	1,426	1,474	1,538
PCB Environmental Compliance	1,702	2,430	758	-	-
Porcelain Cutouts Replacement	2,438	3,507	2,491	-	-
Meter Exchanges	139	140	144	152	162
Other Distribution Sustainment Programs	461	270	1,347	1,367	1,392
Total Distribution Sustainment	**17,480**	**18,219**	**22,446**	**19,014**	**18,291**

18.1 Please explain why Secondary Network and Transformer Connectivity 2023 and 2024 approvals are missing from table C3-38?

Response:

There were no 2023 and 2024 Approved capital expenditures for Secondary Network and Transformer Connectivity because this project does not begin until 2025.

18.2 How has FBC previously documented GIS information with regards to distribution transformers and AMI meter connections?

Response:

Currently each meter connection in the GIS has an attribute that refers to the unique ID of the transformer that feeds it. This database relationship allows for customer reporting functionality and a customer/transformer relationship without secondary network connectivity. There is no secondary network connectivity between the transformer and meter (i.e., secondary conductor objects in GIS) which would allow tracing from transformer to meter.

The relationship between the transformer and meter is established at the as-built stage and maintained by field observations and individual updates to GIS when identified.

The existing transformer to meter relationship was assigned using the closest transformer to the geocoded meter address at the time of first implementation of the GIS platform.

D. Proposed Rate Setting Framework – O&M

19. Reference: Exhibit B-1 Application p. C-11

Declining Customers

19.1 Please explain whether the calculation of formula O&M is sufficiently robust to address decreases in the numbers of average customers.

Response:

Please refer to the response to RCIA IR1 2.1.

19.2 In the event of net decreases in the numbers of customers, formula O&M would decrease each year. Please explain whether this would trigger an off-ramp for reconsideration of the MRP.

Response:

FEI does not expect the off-ramp provision will be triggered in the event of net decreases in the number of customers over the proposed three-year Rate Framework term. Please refer to the response to RCIA IR1 2.1 for FortisBC's expectations regarding changes in average customers during the Rate Framework term.

All else equal, in order to trigger the off-ramp provision, i.e., +/- 150 basis points post-sharing, FEI would need to lose almost half (approximately 41 percent) of the 2024 Approved average number of customers in a single year over any of the next three years.

Although FEI expects there will be a continued trend of declining customer additions due to the impacts of energy transition policy, there is no evidence to suggest FEI will cease adding customers completely over the upcoming three years. As shown in the response to BCUC IR1 8.4.1, FEI has continued to add customers year over year during the Current MRP and current forecasts for 2025 to 2027 indicate that customer additions will continue to occur over the term although in a declining trend (as shown in the response to MoveUP IR1 3.1).

20. Reference: Exhibit B-1 Application p. C-47

Vacancy Rates

In page C-47 of the Application, FortisBC states:

> *"Since 2020, there has been a steady increase in total attrition, particularly regarding retirements and voluntary terminations. There has been increased turnover of voluntary exits from 2.9 percent in 2020 to 8 percent in 2023, as well as increased retirements from 2.0 percent in 2020 to 3.1 percent in 2023 which requires knowledge transfer to build up successors. Additionally, the two positions will support the increasing volume of recruitment and employee movements."*

20.1 Please provide a table showing the total number of either staff, positions, or full-time equivalent positions (whichever FortisBC typically uses) along with vacancy rates for each year for the current and previous MRPs (i.e. 2014 to 2024).

Response:

A table showing the average FTEs and vacancy rates for FEI from 2014 to July 2024 is included below. Vacancy rates are influenced by labour market conditions and the total actual staffing requirements each year.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 July YTD
Average FTEs	1,650	1,573	1,581	1,648	1,727	1,765	1,816	1,914	1,958	1,986	1,993
Vacancy rate	7%	7%	7%	5%	4%	6%	7%	7%	8%	10%	10%

21. Reference: Exhibit B-1 Application p. C-29

CTS TIMC O&M

On page C-29 of the Application, FortisBC states:

> *"In both the 2023 and 2024 Annual Reviews, FEI forecast $0.700 million for incremental resources associated with the CTS TIMC project. In assessing its resourcing needs starting in 2025 (i.e., the start of the Rate Framework), FEI considers $0.900 million to be an appropriate amount to add to 2024 Base O&M. With the additional $0.200 million, FEI will be hiring a fourth senior technical resource from approximately mid-2024 onward."*

21.1 Please provide an updated schedule of inline EMAT inspections of the Coastal Transmission System.

Response:

The following table provides an updated schedule of inline EMAT inspections of the Coastal Transmission System (CTS) as of the date of filing these IR responses.

Pipeline	Anticipated Year of Baseline Run[4]	Updated Schedule	Comments
HUN ROE 1066	2024	2023 (actual) 2024 (scheduled re-run)	As reported in Section 4.1.1 of the CTS TIMC Semi-Annual Progress Report No. 5 for the period January 1, 2024 to June 30, 2024, a sensor failure during the 2023 run occurred and a re-run is scheduled in 2024.
HUN NIC 762	2025	2025	
NIC PMA 610	2025	2025	
NIC FRA 610	2025	2025	
ROE TIL 914	2026	2026	
CPH NOO 508	2026	2026	
LIV PAT 457	2026 (Rerun)	2026 (Rerun)	
TIL BEN 323	2027	2027	
TIL FRA 508	2027	2027	
TIL LNG 323	2027	2027	
LIV COQ 323	2027	2027	

[4] As provided in the July 27, 2021 response to RCIA IR1 14.2 in the CTS TIMC CPCN Application.

21.2 Considering $900,000 is a forecast of the O&M expenses at this point in time, and the resources are not yet in place, please explain whether it makes more sense to maintain EMAT ILI O&M with respect to the CTS as flow-through expenses.

Response:

While FEI is not opposed to continuing to treat the CTS TIMC project incremental O&M as flow-through, FEI considers its proposed approach to move the O&M into the formula to be more appropriate and consistent with how FEI's other controllable O&M is treated.

The $0.900 million described on page C-29 of the Application is for headcount and associated labour related to the incremental inline inspection analysis and Quantitative Risk Assessment activities, and FEI has now fully resourced the positions. These types of expenses, which are generally controllable, are appropriately included in formula O&M.

In contrast, Integrity Dig O&M is highly variable year-over-year due to the considerable uncertainty related to scope, cost, timing, and volume of expected digs. Accordingly, FEI is proposing to continue to treat Integrity Dig O&M as flow-through during the term of the proposed Rate Framework.

22. Reference: Exhibit B-1 Application p.C-30

Property Leases

On page C-30 of the Application, FortisBC states:

> *"Additionally, FEI has entered into a lease for a new contact centre facility in Prince George and is in the process of relocating its employees to this new facility. The incremental leasing (O&M) cost to be added to Base O&M is $0.850 million. FEI is currently evaluating options for the existing facility, including selling or leasing the property."*

22.1 Please confirm whether there are any expiring leases or reductions in space costs that should be reflected in the 2024 Base O&M.

Response:

FEI is the owner of the existing facility in Prince George which had been one of its customer service centres until early 2024. Therefore, there are no leases at the building and as such, there are no expiring leases or reduction in lease revenue for the existing facility.

Regarding expiring leases or reductions in space costs more generally, FEI has one lease expiry (which FEI is the landlord) in 2024; however, the loss in revenue is minimal (estimated at $20 thousand).

22.2 Please explain how the disposal of the existing facility in Prince George will be reflected in O&M and Capital expenses.

Response:

Please refer to the response to BCUC IR1 12.3 for an explanation of how each of the possible options for disposing of the existing Prince George facility (i.e., sale or lease) would impact FEI's rate base and revenue requirement.

23. Reference: Exhibit B-1 Application p.C-30

LNG O&M

On page C-30 of the Application, FortisBC states:

> *"At Mt. Hayes, two operator positions are being added to ensure working alone requirements are met for emergency situations as well as to provide adequate staffing for increased liquefaction requirements experienced at the facility over the past five years. Two operator positions are also required at Tilbury to ensure full vacation and sick coverage and full 24/7 coverage for the operation of that facility. The total cost of these four positions is $0.600 million."*

23.1 Please explain what has changed at the Mount Hayes and Tilbury LNG facilities that they now each require two additional positions that were not previously required.

Response:

Please refer to the response to BCUC IR1 12.5.

24. Reference: Exhibit B-1 Application p.C-31

LTGRP

On page C-31 of the Application, FortisBC states:

> *"In consideration of the recent decision on FEI's 2022 LTGRP, the increasing complexity of resource planning for both gas and electric utilities, and the need to continue to advance the integration of gas and electric resource plans, the Companies have identified an immediate need for three additional positions in 2024 to support their long-term resource planning activities."*

24.1 Please explain how the costs to develop the 2022 LTGRP were reflected in the 2020-24 MRP. Were these costs part of formula O&M or were they capitalized?

Response:

Consistent with the approved treatment, FEI's internal resources for developing the LTGRP are part of the Base O&M. For costs related to external resources that are incremental to the costs already included in the Base O&M, as well as the regulatory proceeding costs for the LTGRPs, FEI has historically sought approval for a deferral account to capture these costs. Most recently, FEI received approval of the 2022 LTGRP deferral account in the Annual Review for 2020-2021 Delivery Rates Decision and Order G-319-20 to record the costs of external consultants, external legal counsel, and the regulatory proceeding related costs (e.g., intervener PCA) associated with the 2022 LTGRP.

FEI expects to seek approval for a deferral account to capture external costs and proceeding costs for the 2026 LTGRP in a future Annual Review during the proposed Rate Framework term.

25. Reference: Exhibit B-1 Application p.C-39

Customer Outreach

On page C-39 of the Application, FortisBC states:

> *"FEI proposes to increase its communication resources starting in 2025 to support the increasing need and expectations that customers, and the public, have around receiving the information they need when they need it, which can occur in several ways (from in person to written or digital). The incremental funding of $0.275 million is requested for two positions, an Events and Outreach position and a Digital Content Designer."*

25.1 Please explain how the costs of customer outreach and digital content were reflected in the 2020-24 MRP.

25.1.1 Were these activities outsourced? If so, will these external costs no longer be incurred and therefore will be removed from Base O&M?

25.1.2 If customer outreach and digital content were outsourced, please identify the annual costs of these activities.

Response:

The cost to communicate with customers, regardless of the platform, has been included in formula O&M within the Current MRP and the proposed Rate Framework.

However, over the course of the Current MRP term, customers' expectations for flexible communication channels that allow for ease of interaction, convenience and responsiveness, have continued to grow. Specifically, FEI has identified a need to add additional positions to support its digital and in-person event communications to meet these growing customer expectations. This reflects the growth of and customer interest in new and more prominent channels that have emerged since the Current MRP was developed, which includes but is not limited to social media, podcasts, and streaming TV. Further, there is an increasing need for in-language and in-person communications due to the increasing linguistic diversity of the population in BC.

Thus, to meet this growing need, FEI has proposed funding for two incremental positions to be added to the 2024 Base O&M, which have not been outsourced nor previously included in Base O&M.

26. Reference: Exhibit B-1 Application p.C-41

Contaminated Sites Regulation

On page C-41 of the Application, FortisBC states:

> *"For example, the HCA [Heritage Conservation Act] is currently being revised to incorporate the UNDRIP/DRIPA principles. FortisBC anticipates increased assessment and permitting requirements for heritage/ archaeological resource management. It is anticipated that changes to the HCA will be passed into legislation in the Fall of 2024."*

26.1 Please explain whether and provide the quantum of any costs that have been incurred to date related to the proposed changes to the Heritage Conservation Act.

Response:

The Province's Heritage Conservation Act Transformation Project (HCATP) aims to reform the *Heritage Conservation Act* (HCA) to align with the UNDRIP/DRIPA and is being undertaken in phases and in consultation and cooperation with First Nations. The first phase led to a package of proposed short-term legislative, regulatory, policy, and programmatic changes, on which the Province conducted further engagement. The Province is now considering a more comprehensive package. As indicated by the Province, while it works to amend the HCA, the Ministry of Forests' Archaeology Branch is being directed by the spirit of the feedback it has received through consultation, and will continue to work towards government's commitments to implement the UNDRIP/DRIPA.

Consistent with the above, FEI has already seen increased assessment and permitting requirements for heritage/archaeological resource management, particularly related to Indigenous community requirements and expectations. These increasing requirements arise as part of the HCA permitting process. FEI is unable to separate out the quantum of any costs incurred to date; however, FEI can confirm an upward trend in costs as regulators consult with Indigenous communities.

It would not be appropriate to move a portion of the Environment and Sustainability O&M from formula to flow-through. These costs have always been included in formula O&M as they are generally controllable and expected to escalate annually in accordance with inflation. While the HCA changes have not yet been passed into legislation, the activities and costs related to increased assessment and permitting requirements are already being experienced by FEI, and FEI has proposed a net incremental funding amount that reflects its funding needs over the Rate Framework term. It is expected that activities and funding requirements will vary year-over-year during the Rate Framework term, and FEI will manage these variations within the approved formula spending envelope.

26.2 Considering the HCA changes have not been passed into law, please discuss the merits of recovering these as flow-through costs instead of as formula O&M.

Response:

Please refer to the response to RCIA IR1 26.1.

27. Reference: Exhibit B-1 Application p.C-46

LNG Plant Maintenance

On page C-46 of the Application, FortisBC states:

"Net incremental funding of $0.400 million is required for the following reasons:

- *FEI plans to add a warehouse position to manage the flow of spare parts and consumables required for the ongoing operation of the Tilbury 1A facility.*
- *FEI requires funding to manage ongoing maintenance requirements over the term of the Rate Framework, including regulatory requirements to complete pressure safety valve (PSV) recertifications, funding for increased material and facility costs related to increased Mt. Hayes production, and work to complete major equipment maintenance."*

27.1 Please explain why the funding for ongoing maintenance at Mount Hayes is not sufficiently provided through the existing Base O&M and inflationary increases, considering the plant has been in operation for many years including for prior recertifications of the PSVs and other major maintenance.

Response:

The portion of the $0.400 million of net incremental funding requested for the Mt. Hayes LNG facility is related to increased material and facility costs to support increased production levels experienced during the Current MRP term and not for ongoing maintenance. In contrast, FEI is requesting additional funding to support maintenance requirements at the aging Tilbury facility.

28. Reference: Exhibit B-1 Application p.C-47

Workforce Development

On page C-47 of the Application, FortisBC states:

> *"The $0.400 million net incremental funding provides for three additional positions focused on recruitment, corporate employee skills, and competencies development for all employees. Of the three positions, two are for recruitment and corporate employee training/development program(s), with the remaining position for supporting multi-year employment contracts with Indigenous communities."*

28.1 Please confirm whether all three positions are expected to be filled by January 2025. If not, please identify when each position is expected to be filled and explain whether the Base O&M should be adjusted to reflect the timing of these hires.

Response:

Please refer to the response in BCUC IR1 13.2.1.

E. Proposed Rate Setting Framework – Capital Expenditures

29. Reference: Exhibit B-1 Application p.C-73 to C-77; 2023 Annual Review of Delivery Rates Exhibit B-2 p.59

Unit Cost Growth Capital

FortisBC provides Table C3-3 and shows the unit cost growth capital forecasted for 2024 in Table C3-3 is $9,654, a 30% increase over the $7,422 in 2023.

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**

On page C-73 of the Application, FortisBC states:

> *"As shown in the above table, although the number of Gross Customer Additions has declined since 2021, the unit costs have been increasing."*

On page C-74 of the Application, FortisBC states:

> *"The impact on FEI's Growth capital has been similar to what has been experienced in FEI's Sustainment capital portfolio and by other utilities in North America over the same period. As discussed in FEI's Annual Review for 2023 Delivery Rates, gas utilities across North America saw an average escalation of 31.2 percent in capital costs between the first quarter of 2020 and the first quarter of 2022.*
>
> *As part of the Annual Review for 2023 Delivery Rates Decision and Order G-352-22, FEI received approval of increases to its Sustainment capital forecasts for 2023 and 2024 to reflect these cost pressures."*

In its Annual Review for 2023 Delivery Rates, FEI stated on page 59:

> *"In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FEI's experience, FEI engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility*

transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 31.2 percent in capital costs for gas utilities between the period of the first quarter of 2020 and the first quarter of 2022. [underlining added]"

On page C-77 of the Application, FortisBC states:

"To avoid understating the starting base UCGC for the years 2025 to 2027, FEI proposes in this Rate Framework to calculate the starting Base 2024 UCGC by extrapolating from a linear regression of Actual UCGC between 2021 and 2023 (inflation- adjusted to 2024 dollars)."

29.1 Please provide data supporting the forecast unit cost growth capital of $9,654 for 2024, including data supporting the single-year inflationary increase of 30%.

Response:

Please refer to the response to CEC IR1 7.1.

29.2 Please explain why using the anomalous two years of 2021 and 2022, when the post-COVID supply chain impacts and Ukraine war had the greatest impact on prices, is an appropriate method to extrapolate inflationary increases into the future.

Response:

As discussed in Section C3.3.1.1 of the Application and further explained in the response to CEC IR1 7.1, FEI experienced significant upward pressure in Growth capital since 2021 due to a number of factors, including unprecedented inflationary increases, an increased complexity of mains installations, increased local government restrictions and permitting requirements, and an increased number of system improvements. FEI expects the impact of these pressures to remain in the unit cost of growth capital (UCGC) during the proposed Rate Framework term. For example, as discussed in response to CEC IR1 7.1, the inflated prices for commodities and services have remained at a high level into 2024 and increases in contractor costs are now reflected in renewed contracts in 2024 that will remain in place for three years. Therefore, including the data from 2021 and 2022 ensures that the recent trends and increases in construction costs are captured as part of the linear regression when determining the 2024 Projected Base UCGC.

29.3 Please explain whether a single-year 30% inflationary increase, as proposed by FEI for UCGC for 2024, makes sense considering the increase in UCGC for 2023 – with the contemporaneous post-COVID supply chain and Ukraine war impacts – was 17% ($7,422 vs. $6,329).

Response:

Please refer to the response to RCIA IR1 29.2.

29.4 Please explain whether regressing the UCGC amounts for 2021, 2022, and 2023 after adjusting them to 2024 dollars amounts to double-counting the effects of inflation.

Response:

Converting the 2021, 2022, and 2023 UCGC to 2024 dollars before the linear regression is not double counting the effects of inflation. In fact, the approach takes the inflation factor (the I-Factor within the Growth capital formula) out of the linear regression model by having all the data converted to 2024 dollars. This way, the regression model (i.e., the 2024 Base UCGC) captures the escalation from 2021 to 2023 due to factors other than CPI/AWE within the I-Factor calculation of the Growth capital formula, such as the inflationary increases or contractor price increases that are additional to the CPI/AWE. The 2024 Base UCGC (in 2024 dollars) is then escalated to the 2025 UCGC based on the 2025 inflation factor.

29.5 Please calculate the percentage increase in unit cost growth capital in 2023 from 2022, and identify the percentage amount that this is above the formula inflationary increase (CPI + AWE) for 2023.

Response:

As explained in Section C3.3.1.1 of the Application, the increase in Growth capital during the Current MRP was due to a number of factors, including unprecedented inflationary increases, increased complexity of mains installations, increased local government restrictions and permitting requirements, and an increased number of system improvements. Further, the inflationary increase experienced by FEI within the context of Growth capital was not limited to CPI/AWE only. Please refer to the response to CEC IR1 7.1.

FEI notes that the I-Factor (i.e., CPI/AWE) between 2022 and 2023 is 4.43 percent out of the 17.3 percent overall increase. Thus, the percentage increase in the UCGC from 2022 to 2023 above CPI/AWE is approximately 12.87 percent.

29.6 Please provide data that show other North American utilities have experienced inflationary increases in the cost of installing mains and services approaching 30% in a single year and more than double the costs in 2021.

Response:

Please refer to the response to CEC IR1 7.1.

On page C-75 of the Application, FortisBC states:

"For example, main installations for high density dwellings require a larger main pipe size diameter to service a much more diverse load profile."

29.7 Please explain why a larger pipe size serving a high-density dwelling increases the unit cost growth capital. Shouldn't there be economies of scale where a single main serving many customers results in a decrease to the UCGC?

Response:

While there are economies of scale with large installations serving many customers (decreased duration and costs for meter installations, for example), the savings do not outweigh the increased costs identified below.

Larger diameter pipe installations are more expensive than smaller diameter installations for a variety of reasons including:

- Greater pipe and fitting costs;
- Increased pipe and fitting material handling complexity (pipe and most fittings cannot be moved by hand or by one person, requiring increased labour and lifting equipment to load and unload for transport and offloading);
- Greater trench width and depth and larger/deeper bell-holes for tie-in resulting in increased excavation durations and trucking costs;

- Greater hard surface (concrete panels, curbs, paving) removal and replacement costs, and increased backfill materials costs;
- Longer durations for welding and fusing fittings;
- Longer durations for tie-in procedures; and
- Increasing labour, supervision, and traffic control costs due to longer construction duration.

Furthermore, large diameter pipe often conflicts with other utilities and can pose a greater challenge to resolve. This often requires deep excavations and multiple fitting (as opposed to simply bending pipe) to route the pipe underneath existing utilities. High density dwelling installations are also frequently installed in areas where there is high potential of utility congestion which will require additional coordination between utilities vying for limited space in smaller areas, increasing the complexity of both the planning and execution of these works.

30. Reference: Exhibit B-1 Application p.C-72, C-80, C-81, C-83, C-87

Capacity Increase Capital

On page C-72, FortisBC states:

> *"FEI's Growth capital expenditures consist of the installation of new mains, services and meters necessary to attach new customers to the gas distribution system, as well as distribution pressure (DP) system improvements required when the capacity of the gas distribution system at a specific service location is insufficient to meet an adequate level of inlet pressure to ensure reliable service to customers."*

On page C-83, FortisBC provides Table C3-8 which identifies Sustainment Capital expenditures including pipeline capacity improvements.

On page C-87, FortisBC states:

> *"Distribution System Capacity Alterations: There is a larger expenditure scheduled in 2025 to address a large load coming online in Mission. This project is approximately $3.1 million and is further described below."*

30.1 Please clarify whether pipeline and station capacity capital expenditures are classified as Growth Capital or Sustainment Capital, or provide more information about how the types of capacity capital expenditures are distinguished.

Response:

Consistent with the treatment approved for the Current MRP, FEI has included the costs for Distribution System Improvements in Growth capital. FEI considers categorizing these capital expenditures as Growth capital to be appropriate because the expenditures are driven by the addition of new customers onto the system.

Transmission and intermediate pressure pipeline and station capacity capital expenditures are classified as Sustainment capital. This classification is appropriate because the relationship between these larger system upgrades and customer growth is often less direct, since a new station or pipeline looping project could lag a significant portion of the customer additions that drove the need.

30.2 Please confirm and explain why the System Improvements shown in Table C3-3 are not repetitive of the capacity additions shown as Transmission System Reliability and Integrity and Distribution System Reliability in Tables C3-5, C3-6, C3-8, and C3-10.

Response:

FEI confirms that the System Improvements (DP) forecasts shown in Table C3-3 are not repetitive of any capacity additions shown in Tables C3-5, C3-6, C3-8 and C3-10. When a capacity project is identified, FEI assigns it to a portfolio which falls into the category of either Growth or Sustainment capital. This enables FEI to ensure that investments are not repetitive or double counted.

31. Reference: Exhibit B-1 Application p.C-81

Meter Capital

On page C-81, FortisBC provides Table C3-7:

Table C3-7: FEI Approved and Forecast Customer Measurement Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Meter Materials	20,589	20,854	9,642	10,849	10,055
Residential Meter Alteration & Exchange	6,856	7,029	36	37	38
Small Commercial / Industrial Meter Alteration & Exchange	1,086	1,064	1,062	1,073	1,083
Large Commercial / Industrial Meter Alteration & Exchange	1,484	1,547	3,555	1,500	2,247
Total Customer Measurement	**30,015**	**30,494**	**14,295**	**13,459**	**13,422**

31.1 Considering most customer meters are being replaced under the AMI project, please explain why there are approximately $10 million per year of meter materials in the Customer Measurement Capital Expenditure forecast.

Response:

The approximately $10 million per year of forecast meter capital expenditures for 2025 to 2027 are for required gas measurement-related materials, labour and vehicle costs unrelated to the AMI project. These remaining cost categories within meter capital include large commercial and industrial meters, gas pressure regulators, and pre-fabricated meter sets (meter sets that are fabricated in the shop prior to being sent into the field including a meter, gas pressure regulator, piping, and communications devices).

32. Reference: Exhibit B-1 Application p.C-92

Fleet Services

On page C-92 FortisBC states:

> *"**Fleet Services:** This category includes the replacement and/or acquisition of specialized heavy fleet vehicles, specialty equipment, mid-duty service vehicles, light duty passenger vehicles, and off-road vehicles necessary to meet FEI's operational requirements. Over the next few years, FEI has a substantial capital replacement requirement based on replacement triggers identified by age, engine hours, and utilization to maintain safe and reliable vehicles and equipment able to respond to customer calls and provide emergency response. FEI plans to replace 123, 84 and 95 vehicles in 2025, 2026 and 2027, respectively. These replacements encompass light duty, medium duty and heavy-duty trucks and vans, trailers, and other equipment."*

32.1 Please provide FEI's specific replacement criteria for light and medium duty vehicles.

Response:

FEI's replacement criteria for light and medium fleet vehicles are as follows:

- Gasoline units: 10 years or 200,000 kilometres whichever comes first.
- Diesel units: 10 years or 220,000 kilometres whichever comes first.

These thresholds ensure optimal vehicle performance and cost-efficiency while minimizing maintenance-related downtime.

32.2 Please explain whether FEI reassigns lower mileage vehicles with higher age to operators who incur higher mileage in order to balance the age and mileage on the vehicles. If not, please explain why not.

Response:

Where possible, FEI strategically reassigns low mileage, high age vehicles to operators who typically accumulate higher mileage, considering both mileage and engine hours to balance utilization across the fleet. This strategy optimizes vehicle usage, extends the fleet lifespan, and ensures that both mileage and engine hours are effectively distributed.

33. Reference: Exhibit B-1 Application p.C-44, C-95, C-97; Exhibit A-4 BCUC IR1 21.2

Information System Capital

On page C-44 FortisBC states:

> *"Another contributing factor to the higher forecast of software licensing fees is that for the renewal and purchase of software, the trend in ownership of software application solution(s) is moving away from the current "on-premises" model to a different model of SaaS (Software as a service – Cloud). Some vendors are withdrawing the option of an "on-premise" solution that FortisBC currently owns, necessitating the transition to SaaS. As SaaS is a different ownership and support model, its ongoing costs are higher than the traditional "on-premise" model. On-premise licensing typically involves a higher initial capital cost with a lower O&M cost for ongoing maintenance licenses. This expected trend towards SaaS is forecast to increase software licensing costs for FortisBC."*

On page C-95 FortisBC provides Table C2-23:

Table C3-23: FEI Approved and Forecast IS Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
IS Sustainment	10,808	10,913	14,800	15,200	15,800
Application Enhancements	2,850	2,850	2,000	2,100	2,200
Business Technology Applications	10,800	10,800	8,500	8,500	8,500
Total Information Systems	**24,458**	**24,563**	**25,300**	**25,800**	**26,500**

33.1 Please explain why IS sustainment costs are increasing if FortisBC is moving to SaaS-type software arrangements, as FortisBC claims as justification for incremental O&M funding.

Response:

Information Services (IS) Sustainment encompasses the upgrade/replacement of desktops, laptops, network, printers, mobile devices, infrastructure and initial licensing costs of applications. Costs for these types of expenditures have increased overall.

Although there is a trend towards SaaS (software as a service – cloud), the majority of FortisBC's major applications (i.e., SAP) continue to be on-premise and FortisBC has experienced an increase in O&M software license renewals for these applications. Further, expenditures such as desktops, laptops, printers, and mobile devices are unaffected by the move towards SaaS.

As FortisBC moves more applications to SaaS, there is expected to be further O&M increases; however, no major systems are moving during the three-year Rate Framework term.

BCUC IR1 21.2 requests:

> *"Please explain why patch management is a capital expenditure as opposed to an operating expenditure."*

33.2 Please explain the distinction between patching costs classified as an O&M expense in Table C2-8 on page C-44 and the patching costs classified as capital and included in Table C3-25 on page C-97.

Response:

Please refer to the response to BCUC IR1 21.2.

34. Reference: Exhibit B-1 Application p.C-98

Mobile Incident Command Centre

On page C-98 FortisBC states:

> *"British Columbia has been experiencing increases in the frequency and severity of emergencies and disaster events which have significant impacts and durations that exceed those of previous years, and it is expected that this trend will continue. FEI requires the ability to establish incident command support bases to serve areas where facilities and infrastructure do not exist, or where space to respond to emergencies is an issue. To address this, in 2025, two mobile incident command units will be purchased and strategically positioned in areas where they can be easily deployed to support an event(s)."*

34.1 Considering FortisBC has responded to emergencies in the past, please explain how and in what locations it has previously established incident command centres.

Response:

Previously, FEI has established incident command posts in its own facilities, borrowed facilities, or used a Company vehicle nearest to the incident. Incident command posts are most effective when located as close as possible to the incident sites. Field personnel muster at the incident command post and then travel to the incident location, which, without a mobile incident command unit, may be a substantial distance, forcing incident command personnel to communicate remotely with field personnel. Mobile incident command units will provide a safe shelter with restrooms, technology, communications, food, hydration, local planning, as well as a muster point near incident sites to support effective response and recovery.

The requirement for the mobile incident command units has been determined through post incident response reviews for simulated and actual events. The lessons learned from simulated and actual events have indicated that investing in mobile incident command units would improve FEI's incident response capabilities where its facilities or other reasonable locations are not available near an incident.

FEI's critical infrastructure is distributed over a large geographic region where incidents requiring a coordinated response may be in remote areas. In the case of incidents in remote areas, the current approach to establishing an incident command centre is less efficient than a mobile incident command centre for the reasons described above.

34.2 Please explain why FortisBC's prior approaches to responding to emergencies and incident command centres cannot continue in the absence of procuring the proposed mobile ICCs.

Response:

Please refer to the response to RCIA IR1 34.1.

35. Reference: Exhibit B-1 Application p.C-101

SAP Modernization and Replacement

On page C-101 FortisBC states:

> *"At nearly 25 years old, this system is no longer supported by the software manufacturer and requires ongoing customized support to ensure the continued accuracy and security of customer billing information. FBC intends to align the customer billing system with FEI's system. As such, FBC will be seeking to replace the current CIS+ system with SAP S/4 HANA at the same time as FortisBC transitions to SAP S/4 HANA."*

35.1 Please explain whether FortisBC has explored continuing the use of its existing SAP system using third-party (non-OEM) support. Please provide the pros and cons of such an approach

Response:

FortisBC is not requesting approval of the SAP Modernization and Replacement project as part of this Application. As part of the future application seeking approval of this project, FortisBC will describe the need for the project and alternatives considered, as appropriate.

F. Proposed Rate Setting Framework – Clean Growth Innovation Fund

36. Reference: Exhibit B-1 Application p.C-158

CGIF Governance

On page C-158 FortisBC states:

> *"The governance processes established for the 2020 CGIF have been effective and contributed to the overall success of the fund in accelerating the pace of clean energy innovation."*

36.1 Please confirm whether any external parties (e.g., accounting firms, external auditors, etc.) have audited the CGIF expenditures for eligibility according to the established criteria or for conflicts of interest (e.g., FortisBC employees or family members with fiduciary interests in the funded projects). If confirmed, please provide the auditor's reports. If not confirmed, please explain why not.

Response:

FEI's financial statement balances and controls, including balances and controls for regulatory assets and liabilities (which includes the CGIF account), are audited by an external auditor annually. While the CGIF has not been specifically audited by an external party for eligibility, the CGIF has followed the governance model discussed in Section C5.2.1 of the Application. Additionally, all of FEI's employees are governed by a Code of Conduct, which sets out expectations of ethical behavior, including following applicable laws, rules and regulations.

37. Reference: Exhibit B-1 Application p.C-161

CGIF Funds

On page C-161 FortisBC provides Table C5-1:

Table C5-1: Clean Growth Innovation Fund 2020-2024[123] ($ millions)

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Projected 2024	Total
Portfolio Approvals	**$ 1.500**	**$ 2.200**	**$ 1.526**	**$ 4.169**	**$ 7.500**	**$ 16.895**
Opening Balance	**$ -**	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (10.510)**	**$ -**
Funding collected	(2.099)	(5.093)	(5.176)	(5.230)	(5.229)	(22.827)
Expenditures	1.022	1.127	0.972	1.431	6.867	11.419
Accrued committed					5.476	5.476
Tax	0.291	1.071	1.135	1.026	(1.920)	1.603
Financing	(0.005)	(0.130)	(0.301)	(0.551)	(0.494)	(1.481)
Closing Balance	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (10.510)**	**$ (5.810)**	**$ (5.810)**

37.1 Please provide a table of 2020 CGIF funding collected (and projected to be collected in 2024) by rate class. In this table, please also show total gas consumption over the 2020-2024 period by rate class and the average number of customers in each rate class.

Response:

Please refer to Table 1 for the CGIF funding collected, total gas consumption, and average number of customers by rate class, showing actuals for 2020 to 2023 and forecast for 2024.

Table 1: CGIF Funding Collected, Total Gas Consumption, and Average Number of Customers by Rate Class (Actual 2020 to 2023 and Forecast 2024)

	2020 Actual			2021 Actual			2022 Actual			2023 Actual			2024 Forecast		
Rate Class	CGIF Funding Collected ($000s)	Volume (PJ)	Average Number of Customers (000s)	CGIF Funding Collected ($000s)	Volume (PJ)	Average Number of Customers (000s)	CGIF Funding Collected ($000s)	Volume (PJ)	Average Number of Customers (000s)	CGIF Funding Collected ($000s)	Volume (PJ)	Average Number of Customers (000s)	CGIF Funding Collected ($000s)	Volume (PJ)	Average Number of Customers (000s)
Rate 1	1,904.5	81.3	947.0	4,614.8	83.0	959.0	4,691.1	86.5	968.7	4,737.6	76.5	980.5	4,751.2	83.4	989.8
Rate 2	177.5	28.7	89.0	435.8	29.8	89.3	441.6	32.3	89.5	443.5	27.9	89.6	434.6	29.7	90.6
Rate 3	13.4	24.9	6.7	33.8	26.2	7.0	35.0	28.1	7.1	40.8	28.2	8.5	34.7	27.0	7.2
Rate 4	0.1	0.1	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.1	0.2	0.0
Rate 5	1.1	8.7	0.6	2.8	9.8	0.6	3.0	11.4	0.6	3.3	11.8	0.7	3.2	11.9	0.7
Rate 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Rate 7	0.1	6.5	0.0	0.2	6.4	0.0	0.2	6.2	0.0	0.2	6.6	0.0	0.2	6.8	0.0
Rate 22	0.1	27.6	0.0	0.2	27.7	0.0	0.2	26.5	0.0	0.2	26.5	0.0	0.2	26.8	0.0
Rate 23	1.6	4.5	0.8	3.5	4.1	0.7	3.3	4.2	0.7	2.8	3.3	0.6	3.0	3.6	0.6
Rate 25	0.6	9.3	0.3	1.4	8.8	0.3	1.3	8.2	0.3	1.1	7.1	0.2	1.2	7.8	0.2
Rate 27	0.1	4.6	0.1	0.3	4.4	0.1	0.3	4.3	0.1	0.3	3.9	0.1	0.3	3.9	0.1
Total	**2,099.2**	**196.4**	**1,044.6**	**5,093.1**	**200.4**	**1,057.1**	**5,176.3**	**207.9**	**1,067.2**	**5,230.2**	**192.1**	**1,080.3**	**5,228.8**	**201.0**	**1,089.3**

38. Reference: Exhibit B-1 Application p.C-172, C-173

CGIF Project Eligibility Criteria

On page C-172 FortisBC states:

> *"The energy transition is expected to increase energy costs for British Columbians. The CGIF can play a key role in supporting cost-effective energy solutions for customers by focusing more broadly on innovations that have the potential to reduce costs. To date, the CGIF has focused on cost reductions directly related to the energy transition such as those related to reducing the cost of RNG. However, there are innovations that can help FEI reduce costs in other business areas that will also provide benefits to customers."*

> *"For example, satellite-enhanced vegetation management may be a useful tool with the potential to make vegetation management more cost effective by moving it from a time-based approach to a condition-based approach. Similarly, remote sensing and control has the potential to reduce costs for both utilities by reducing the need to physically visit or continuously monitor gas assets."*

38.1 Please explain how CGIF funding for projects that serve to reduce FEI's costs differ from other optimization and cost reduction projects that FEI would be expected to undertake in the normal course of business in order to achieve efficiencies and reduce its O&M and capital expenditures.

Response:

The CGIF provides funding to accelerate the adoption of innovative technologies that seek to reduce emissions, reduce costs, enhance resilience and optimize the use of the gas system with a focus on pre-commercial technologies that fall within the range of technology readiness levels (TRL)[5] 3 to 9 (i.e., pre-commercial stages). Innovation activities in these stages range from pre-commercial development to commercial demonstration and pilot projects. The governance of the CGIF, as detailed in Section C5.2.1 of the Application, ensures only eligible innovations are funded under the CGIF, which excludes funding for commercially available technologies that would be considered under the normal course of business.

[5] TRL3 is defined as Research to Prove Feasibility and TRL 9 is defined as System Test, Launch and Operations. Please refer to the following website: https://web.archive.org/web/20051206035043/http:/as.nasa.gov/aboutus/trl-introduction.html.

On page C-173 FortisBC states:

> *"Another way to make energy systems more resilient to disruptions in transmission and distribution systems is to increase energy supply and storage capabilities close to customers. Given the technology landscape, it is likely that biomethane and low- carbon hydrogen will be produced in a distributed manner, with production facilities connected directly to the distribution systems or customers."*

38.2 Please explain how FEI will distinguish between resilience-enhancing technologies that are already at or near commercialization (and thus should not be eligible for CGIF funding) compared with those that are in the developmental stage.

38.2.1 Please discuss whether additional CGIF project criteria are required for Resilience projects (for example, to exclude existing LNG storage solutions) and if warranted, propose additional criteria.

Response:

As discussed in the response to RCIA IR1 38.1, the CGIF is focused on pre-commercial technologies that meet the CGIF funding criteria detailed in Section C5.3.1 of the Application. This includes technologies at TRL 9 that are ready for commercial demonstration and pilot projects (i.e., "near commercialization"), but excludes commercially available technologies. As such, there is no need to distinguish between the stages of development specifically for resilience-enhancing technologies.

As discussed in Section C5.3.1 of the Application, FEI has proposed to add "potential energy system resilience benefits for FEI customers" to its evaluation criteria given the growing need to consider innovative technologies that address the need to adapt to a changing climate. FEI does not consider that any further additional project criteria are warranted at this time.

Finally, FEI notes that RCIA's reference to "existing LNG storage solutions" in IR1 38.2.1 seems to be describing technologies that are already commercially available, and, therefore, would not be eligible for funding under the CGIF.

39. Reference: Exhibit B-1 Application p.C-174

CGIF Funding

On page C-174 FortisBC states:

> *"FEI proposes to continue utilizing the innovation rider and to continue to collect $0.40 per month from FEI's customers' bills… At the end of the Rate Framework, the unused balance in the deferral account will be returned to customers."*

39.1 Please calculate the volumetric rate ($/GJ) that would achieve the same funding as the proposed $0.40 per bill fixed charge.

Response:

Based on the current customer and demand forecast for 2025, the equivalent volumetric rate to the fixed $0.40 basic charge rider would be $0.03 per GJ in 2025 (based on 2025 forecast total gas consumption of 207,071 TJ and the forecast average number of customers of 1,102,050). However, FEI does not believe changing the rider from a fixed charge to a volumetric charge would be beneficial to its customers. The fixed rider of $0.40 per month is easy to administer, more stable, and consistent with the existing amount which customers are already accustomed to. Moving to a volumetric rider would require re-calculation each year which would be more administratively burdensome with no added benefits.

As FEI discussed in the Current MRP proceeding, a fixed per-customer rate is preferrable to a volumetric rate for a number of reasons, including that the costs for Innovation Fund activities are largely fixed and do not vary by volume and the reduction of GHG emissions resulting from successful research and development will benefit all customer types, not just higher volume customers. On page 156 of the MRP Decision and Orders G-165-20 and G-166-20, the BCUC concluded:

> The Panel agrees with FEI that a fixed rate rider is more reasonable than a volumetric approach and considers there to be no need for the fixed rate rider to be shown separately on customers' bills as it will be included in FEI's tariff. [Emphasis added]

FEI is proposing no change to the CGIF that would justify a change to a volumetric approach.

39.2 Please confirm whether the uncommitted funds will be returned to customers in the first year following the completion of the 2025 - 2027 MRP (i.e. 2028), similar to the approach proposed for the 2020 CGIF surplus funds.

Response:

Confirmed. FEI proposes that any uncommitted funds will be returned to customers in the first year following the completion of the proposed three-year term of the Rate Framework, similar to the approach proposed for the remaining balance in the 2020 CGIF deferral account.

G. Proposed Rate Setting Framework – Service Quality Indicators

40. Reference: Exhibit B-1 Application Appendix C6-1 p.8,9 2023 FEI Annual Rate Review Exhibit B-4 RCIA IR1 8.1

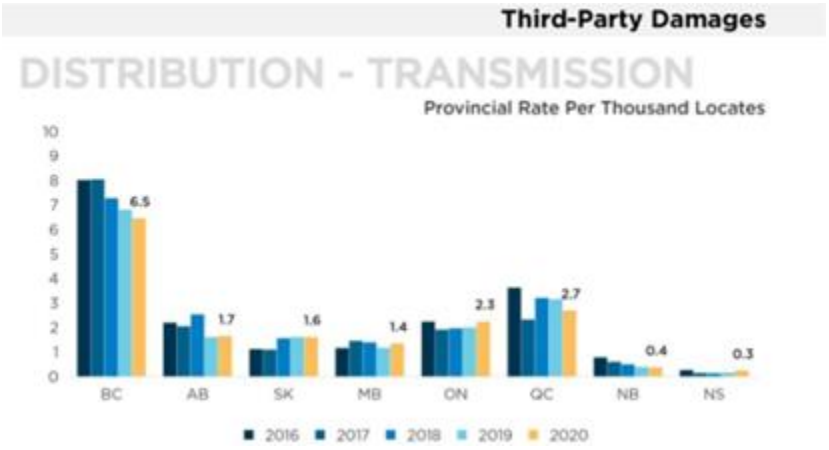
SQI - Third-Party Pipeline Damages

On page 8 of Appendix C6-1, FortisBC provides Table 6:

Table 6: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Public Contact with Gas Lines

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Public Contact with Gas Lines – annual	7	6	6	5	8	6	12	10
BC 1 Call Ticket Volume	141,262	163,584	157,174	158,478	n/a	n/a	n/a	n/a
Line Damages	973	1,034	896	844	n/a	n/a	n/a	n/a

In the response to 2023 FEI Annual Rate Review RCIA IR1 8.1, FEI provided the following information from the Canadian Gas Association:



40.1 Please explain how FEI was able to drive a reduction in public contacts with gas lines as seen in Table 6.

Response:

FEI recognizes the importance of reducing public contacts with buried gas lines to improve public safety. FEI uses the Public Contacts with Gas Lines metric, which reflects the number of line damages per 1,000 calls to the BC 1 Call program, to measure the public's awareness regarding buried gas lines and to minimize damage to the gas system. Reducing damage to the gas system in turn reduces risk to public safety from contacts with buried pipes and associated service interruptions for customers.

The results of the Public Contacts with Gas Lines metric are primarily affected by construction activity levels, damage prevention awareness programs and heightened public awareness created by the BC 1 Call program. The recent three-year rolling average results reflect an ongoing positive trend for this metric which is driven by:

- Increased awareness through targeted workshops with municipalities and excavating contractors;
- Increased collaboration with external agencies, including WorkSafeBC and BC 1 Call; and
- A higher number of calls generated by the BC 1 Call program.

The reduction in public contacts with gas lines may also, at least partially, be driven by external factors which, as noted above, are a primary driver behind the Public Contacts with Gas Lines metric.

40.2 Please explain the process for a customer to have gas lines marked, from contacting BC 1 Call to the lines being marked by FEI (or the proposed excavation area being cleared). Provide average or typical timelines between each of the steps.

Response:

Requests to locate buried gas lines can be made through an online submission or by calling BC 1 Call. Once the necessary information is provided, BC 1 Call passes the information onto the applicable member organizations responsible for the assets (in this case FEI). FEI usually receives notification of the request within a few minutes following its submission. On average, FEI responds to the request within 2-3 business days, providing copies of documents regarding the location of its assets (i.e., gas lines are not normally physically located by FEI). Requests are typically handled in the order they are received, unless a request is deemed to be an emergency or a high priority.

40.3 Please provide an update to the average number of line damages per 1,000 line locate requests for other Canadian gas utilities as aggregated and averaged by the Canadian Gas Association.

Response:

There has been no updated information made available regarding line damages as at the time of filing these IR responses. Further, the information from the Canadian Gas Association (CGA) does not differentiate between line damages to mains versus service lines; as such, FEI is unable provide the information broken down as requested.

In Appendix C6-1 on page 9, FEI states:

> *"FEI also recognizes that damage metrics and statistics can be assessed and presented in any number of formats. As an example, FEI notes that the BC damage numbers (numerator) reported are not significantly disproportionate to BC's proportion of the Canadian population."*

40.4 Provide the average number of line damages per 1,000 customers for other Canadian gas utilities as aggregated and averaged by the Canadian Gas Association.

Response:

Please refer to the response to RCIA IR1 40.3.

40.5 Provide the average number of line damages per 1,000 km of pipeline mains for other Canadian gas utilities as aggregated and averaged by the Canadian Gas Association.

Response:

Please refer to the response to RCIA IR1 40.3.

40.6 Provide the average number of line damages per 1,000 km of pipeline mains and services for other Canadian gas utilities as aggregated and averaged by the Canadian Gas Association.

Response:

Please refer to the response to RCIA IR1 40.3.

40.7 Provide a table or chart showing the number of FEI line damages for 2023 by category (Did Not Call, etc.).

Response:

As shown in the table below, in 2023, BC 1 Call was not contacted prior to digging in nearly two-thirds of line contacts resulting in damage.

Percentage of Contacts to BC 1 Call Where Line Damage Reported in 2023	
BC 1 Call Contacted	36%
BC 1 Call Not Contacted	64%

Of the 36 percent of line contacts resulting in damage where BC 1 Call was contacted prior to digging, 81 percent failed to follow safe digging practices (e.g., hand digging or avoiding digging inside the no mechanized excavation zone).

In Appendix C6-1 on page 9, FEI states:

> *"In contrast, BC 1 Call is a non-profit organization and mandatory membership is only applicable to the industry partners regulated by the British Columbia Energy Regulator (BCER)."*

40.8 Please explain the requirements imposed by BC's legislation and regulator for low-pressure pipelines (i.e. those pipelines not regulated by the BCER) for damage prevention programming, notification of utilities, and line locating.

Response:

In British Columbia, low-pressure pipeline assets that are not regulated by the BCER are regulated under the following provisions of the *Occupational Health and Safety Regulation* and the *Gas Safety Regulations*:

Occupational Health and Safety Regulation[6]

20.79 Underground utility services

(1) Before excavating or drilling with powered tools and equipment, the location of all underground utility services in the area must be accurately determined, and any danger to workers from the services must be controlled.

(2) Excavation or drilling work in proximity to an underground service must be undertaken in conformity with the requirements of the owner of that utility service.

(3) Pointed tools must not be used to probe for underground petroleum and electrical utility services.

(4) Powered equipment used for excavating must be operated so as to avoid damage to underground utility services, or danger to workers.

Gas Safety Regulations[7]

Procedures for a gas installation in vicinity of underground structures

37 (1) A person must not install a gas installation or allow one to be installed so that the gas installation passes through or interferes with any underground structure that is not solely for the use of a gas installation without the written permission of the owner of the underground structure.

Duties of persons intending to construct near gas installation

38 A person who intends to construct an underground structure within one metre of a gas installation must notify the gas company operating in the area at least 2 business days before starting the excavation for the structure.

Procedures for excavations

39 (2) A person who intends to excavate must, at least 2 business days before the person intends to excavate, request from the gas company serving that area, or its agent, information on the location of all underground gas installations in the vicinity of the proposed excavation.

39 (7) The indicated location of gas installations must be confirmed by the excavator by means of hand digging and the excavator must expose the gas installations at a sufficient number of locations to determine their exact

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6 WorkSafeBC.

7 Gas Safety Regulation (gov.bc.ca).

positions and depths before using mechanized excavation equipment for any purpose other than breaking the surface cover.

39 (9) If an excavator finds that the gas installation is not within the limits described by the gas company,

(a) the excavator must so advise the gas company,

(b) the gas company must immediately assist in locating and exposing the installation for the excavator,

(c) mechanized excavation must not be carried on in the vicinity until the installation has been located and exposed.

No probing to locate gas installations

40 A person must not probe with pointed tools to locate gas installations.

In Appendix C6-1 on page 9, FEI states:

"Awareness of the need for a line locate influences the denominator in the calculation. In 2021, approximately 240,000 locate requests were made in British Columbia. In contrast, approximately half a million locate requests were made in Alberta and over a million locate requests were made in Ontario during the same period."

40.9 Provide FEI's actual expenditures for public awareness for each of the years of the current MRP and proposed for the 2025-27 MRP.

Response:

Please refer to the table below for FEI's actual direct expenditures for public awareness for each of the years of the Current MRP term. As these expenditures are part of Formula O&M, consistent with FEI's proposed 2024 Base O&M calculation, the 2023 Actual amount (inflated to 2024) will form part of the 2024 Base O&M and will be escalated annually in accordance with the approved net inflation factor for the term of the Rate Framework.

Year	Expenditures ($000s)
2020 Actual	764
2021 Actual	669
2022 Actual	863

Year	Expenditures ($000s)
2023 Actual	938
2024 Projected	976

40.10 Please comment on whether the fewer number of locate requests in BC represent an opportunity for FEI to increase its public awareness activities in order to educate and encourage excavators to request line locates prior to excavating.

Response:

As discussed in Appendix C6-1 regarding the Public Contacts with Gas Lines metric, public awareness activities contribute to an increase in BC 1 Call activities, which correlates to the reduction in gas line damage for FEI over time. Differences in population density and the level of construction activities between jurisdictions are also factors that influence the level of use of BC 1 Call services and must also be considered when assessing how to reduce gas line damage.

In FEI's view, damage prevention is a joint effort and a shared responsibility with other stakeholders within BC. While FEI provides education about safe digging practices and training opportunities to various municipalities, contractors and other industry organizations, FEI also focuses on its partnership with BC 1 Call, BC Common Ground Alliance, and equipment operator schools, among others, to ensure the ground disturbance communities are aware of the risks associated with not utilizing BC 1 Call services, or not following all safe digging practices.

With these considerations, FEI continually evaluates its public safety awareness activities related to educating and encouraging excavators to contact BC 1 Call to request the location of underground infrastructure before starting any ground disturbance activities.

41. Reference: Exhibit B-1 Application, Appendix C6-1 p.10

SQI – First Contact Resolution

In Appendix C6-1 on page 9, FEI states:

"FCR measures the percentage of customers who receive resolution to their inquiry in one contact with FEI's contact centre."

41.1 Please confirm whether FCR measures only telephone calls to the contact centre, or whether it includes other forms of contact (web portal messaging, email, etc.).

41.1.1 If FCR only tracks telephone interactions, please explain the viability of incorporating other communication channels in the metric.

Response:

FEI uses an external third party to conduct telephone surveys that report the percentage of customers who felt they received resolution to their inquiry in the first contact for telephone and chat interactions. FCR measures the resolution in those specific channels and is aligned with the interactions used to derive the Telephone Service Factor (TSF).

While it may be feasible for FEI to incorporate FCR surveys for customers who use other non-telephone channels, such as email interactions, FEI considers that the Company's current approach provides an accurate representation of FEI's overall FCR performance. FEI also expects there would be additional costs associated to implement measurement of these other channels.

42. Reference: Exhibit B-1 Application pp.C-27, C-184; Appendix C6-1 p.14

SQI – Meter Reading Completion

On page C-27, FEI states:

> *"In order to treat O&M costs impacted by the AMI project as a flow- through item, FEI has removed the 2023 Actual Meter Installation, Meter Reading, Operations, Customer Service and Meter Shop O&M costs from the Base O&M unit cost."*

In Appendix C6-1 on page 14, FEI states:

> *"The timing of the AMI project deployment has necessitated changes to the treatment of a number of areas of the Rate Framework. In particular, and as explained in Section C2.2.2.2 of the Application, FEI is proposing to remove AMI-related costs from Formula O&M and to instead treat these costs as Flow-through for the duration of the Rate Framework term."*

42.1 Please confirm whether FEI intends to remove all meter reading and replacement costs from formula O&M, or only AMI-related costs.

Response:

FEI is proposing to remove all of the meter reading and replacement costs related to the manual costs of reading meters and the cellular costs for large commercial and industrial meters from formula O&M during the term of the Rate Framework, not just the AMI-related costs. These costs have been removed from the 2024 Base O&M shown in Table C2-1 of the Application.

42.2 Please explain whether FEI could maintain the Meter Reading Completion metric with a benchmark and threshold for those meters that continue to be read manually, until such time as the AMI project is completed, recognizing that the metric would apply to a diminishing number of meters each year.

Response:

FEI considers that there would be limited value and high administrative effort associated with maintaining the benchmark and threshold for a declining portion of meters as the AMI project progresses. Isolating a portion of the meters to calculate this metric would require additional reporting and tracking mechanisms that are not currently planned for or in place. Further, due to the declining number of meters – which will result in a smaller denominator each month – the metric may be more susceptible to fluctuations and volatility that may not be reflective of the overall service quality experienced by FEI's customers.

As such, FEI is proposing to change the Meter Reading Completion metric to an informational indicator (with no benchmark and threshold) for all meters while the AMI project is deployed. FEI would then re-visit the metric once the AMI project is complete, and the AMI meters are fully deployed.

The Meter Reading Completion metric ensures FEI is providing customers with timely and accurate bills. Maintaining the Meter Reading Completion metric as an informational indicator for both automatic and manual meter reads during deployment of the AMI project strikes an appropriate balance by providing the BCUC and interveners with information regarding meter reading completion rates, while recognizing using a benchmark and threshold will no longer provide an effective means of assessing FEI's service quality due to the mix of meter types (manual and advanced).

43. Reference: Exhibit B-1 Application Appendix C6-1 p.14,18

SQI – TSF (Non-Emergency, Average Speed of Answer

In Appendix C6-1 on page 14, FEI states:

> *"The TSF (Non-Emergency) SQI measures the percentage of non-emergency calls that are answered in 30 seconds."*

In Appendix C6-1 on page 18, FEI states:

> *"The Average Speed of Answer (ASA) metric is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (in seconds). The ASA was proposed (and approved) as an informational indicator in the 2020-2024 MRP Application and remains complimentary to the TSF as it provides additional insight on the customer experience for calls that are answered in over 30 seconds, with shorter wait times for customers preferable to longer wait times."*

43.1 Please explain whether it would be feasible to develop an additional SQI that reports on the average response time for non-telephone inquiries to be responded to by FEI, or the percentage of responses within a set period, such as two business days.

43.1.1 Please discuss the merits and drawbacks of such an SQI, including whether it would be appropriate as a benchmarked indicator or an informational indicator.

Response:

It may be feasible to develop an additional SQI that reports on the average response time for non-telephone inquiries such as email and account online; however, not all of FEI's non-telephone systems currently have this tracking capability and introducing this capability, if possible, would require system investments which would increase costs for customers. A single SQI may also not reflect the variety of industry standards used for all non-telephone interaction types. For example, each interaction type may have different levels of complexity or priority, resulting in different response times.

Further, FEI does not consider that the proposed SQI would ensure that service quality to customers is maintained at acceptable levels throughout the term of the Rate Framework and, as such, developing an additional SQI and incurring the associated incremental costs are not warranted at this time.

If FEI were to consider such an SQI in the future, FEI would first need to assess its system capabilities to determine what could be tracked (and the cost to incorporate a tracking capability if one does not currently exist), and the administrative effort to track and report on an additional SQI of this nature. FEI would also need to undertake research to determine if other utilities in

1 other jurisdictions track the average response time for non-telephone inquiries in order to
2 understand what an appropriate metric would be.

3

44. Reference: Exhibit B-1 Application pp.C-185-186; Appendix C6-1 p.1-3; Exhibit A-4 BCUC IR1 4.1, 33.5

SQI – Potential Additional SQIs – Customer Connections, GHG Emissions

FEI provides Table 1 in Appendix C6-1 which lists the current and past SQIs.

44.1 Please explain whether FEI has received complaints from customers and potential customers with respect to the time to install new service lines or to make alterations to existing service lines.

Response:

FEI has at times received complaints from customers and potential customers with respect to the time to install new service lines or to make alterations to existing service lines. While FEI does not track the specific number of complaints by category, anecdotally complaints related to installing new service lines or to make alterations to existing service lines are relatively few in comparison to the number of service orders FEI completes each year.

44.2 Please explain whether it would be feasible to develop an additional SQI that reports on the average time for FEI to complete a new service connection. Such a metric could track the average time from when a potential customer completes an application for a new service until the time FEI's activities are complete (i.e. the service line and meter are installed, ready for the customer to complete any work on their side of the meter).

Response:

Since many of the drivers behind the average time for new service connections and alterations are beyond FEI's control and would materially impact the results of the metric, it would not be feasible to develop an additional SQI that reports on the average time for FEI to complete a new service connection or to complete a service alteration. These drivers include:

- **Permitting Timelines:** Each municipality has specific timelines and requirements for permitting which can impact timelines for works to begin. In particular, environmental and archeological permitting requires significant time to submit and receive approval. The time it takes for permitting applications is influenced by factors such as the complexity of the associated works, the volume of other permitting applications and, as noted above, timelines will vary between municipalities.
- **Variable Application Timing:** There is significant variability in when customers contact FEI requesting a new service connection or to complete a service alteration. For example,

some customers may contact FEI a year in advance, while others may wait until a week before the request is needed. A metric tracking when a customer completes this type of application would not accurately report or differentiate between delays in the completion of work that are due to FEI's performance (i.e., lack of timeliness) and customers contacting FEI without sufficient lead time. Early contact from customers has a number of benefits and is encouraged because it provides FEI time to complete the necessary design process and seek required permits.

- **On-Site Delays:** Factors beyond FEI's control can result in on-site delays affecting FEI's ability to complete the requested work. For example, FEI may have scheduled crews only to find the customer is not ready due to scheduling changes, or that the site conditions prevent undertaking the work.
- **Seasonality:** Depending on the time of year, a request for a new service install or service alteration may come in during a period of time where work would not be scheduled due to seasonality causing unfit working conditions, such as frozen ground.

The above factors would make it difficult to select an average completion time that accurately and fairly represents whether FEI's service quality in this regard has deteriorated.

Ultimately, given the complexities of new service and alteration requests, FEI does not consider including an SQI on the completion timing of such requests would be appropriate.

However, FEI uses the Customer Satisfaction Index (CSI) to assess overall customer satisfaction with the Company's natural gas service, including new service connections and alterations. The CSI score includes feedback from customers regarding their experience though the process from initial contact through to installation touch points from customer service and field services. The CSI reflects a customer's perspective regarding how satisfied they were with the services FEI has provided.

44.3 Please explain whether it would be feasible to develop an additional SQI that reports on the average time for FEI to complete service alterations. Such a metric could track the average time from when a customer completes an application for alterations to their service until the time FEI's activities are complete (i.e. the service line and meter are installed, ready for the customer to complete any work on their side of the meter).

Response:

Please refer to the response to RCIA IR1 44.2.

44.4 Please discuss the merits and drawbacks of such SQIs as described in the previous two questions, including whether they would be appropriate as benchmarked indicators or only as informational indicators.

Response:

Please refer to the response to RCIA IR1 44.2.

On page C-185, FEI introduces new metrics related to the energy transition. In Exhibit A-4, BCUC IR1 4.1 requests FEI's historical and forecast annual GHG emissions from energy delivered to the buildings and industrial sectors for each year from 2018 through 2030.

BCUC IR1 33.5 further requests the following:

> *"Please provide, in a similar format to Table C6-6 of the Application, historical data on the overall GHG emissions from all customers for each year from 2020 through 2023."*

44.5 Further to the BCUC's request, please clarify whether the overall GHG emissions are those that count toward the GHG Reduction Standard's emissions cap. If not, please provide a separate table showing those emissions that are relevant to the emissions cap.

Response:

Based on the information provided in the CleanBC Roadmap to 2030, FEI understands that the proposed GHGRS cap on GHG emissions will include emissions from energy delivered to buildings and industrial sectors. FEI has provided an estimate of the GHG emissions from these sources in the response to BCUC IR1 4.1 and its expected share of the cap in the response to BCUC IR1 4.2.

44.6 To the extent this has not been addressed in BCUC IR1 33.5.1 and 33.5.1.2, please discuss the merits of a new informational indicator that tracks FEI's progress towards meeting the GHG Reduction Standard's emissions cap.

Response:

Please refer to the response to BCSEA IR1 3.1.

Appendix – Report on Indexing Formula Components for FortisBC

45. Reference: Exhibit B-1 Application, Appendix C1-1 p. 22

On page 22 of Appendix C1-1, the Report states:

> "For example, when Boston Gas's first incentive regulation plan expired and a new plan was implemented, the approved stretch factor (which in Massachusetts is called a "consumer dividend") fell from 0.5% to 0.3%, which is a 40% reduction."

45.1 Please provide evidence across several jurisdictions that show stretch factors for utilities in both gas and electricity decreasing with successive rounds of incentive regulation.

Response:

The following response was provided by Dr. Kaufmann:

The most relevant data "that show stretch factors…decreasing with successive rounds of incentive regulation" comes from the Ontario electricity distribution industry. In 2013, the Ontario Energy Board (OEB) implemented Fourth-Generation Incentive Regulation (4thGenIRM) for electricity distributors in the province. One important element of 4thGenIRM was a performance-based method for setting, and updating, stretch factors for electricity distributors annually. In the first year of 4thGenIRM, electricity distributors were assigned to one of five stretch factor cohorts based on their measured cost performance on a benchmarking model.

- Distributors with the worst measured cost performance were assigned a stretch factor of 0.6 percent.
- Distributors whose cost performance was above the bottom tier but below average were assigned a stretch factor of 0.45 percent.
- Distributors with average cost performance were assigned a stretch factor of 0.3 percent.
- Distributors that were above average, but not the very best, were assigned a stretch factor of 0.15 percent.
- Distributors with the best cost performance were assigned a stretch factor of zero.

However, in each subsequent year of 4thGenIRM, each electricity distributor's stretch factor was updated based on their updated cost performance. Each company's cost performance was re-calculated annually using the same, original benchmarking model. The criteria used to link measured cost performance to stretch factor assignments were similarly unchanged. Because these standards for measuring cost performance and assigning stretch factors based on measured cost performance have been fixed since 2013, any movements of electricity distributors from one stretch factor cohort to another will reflect changes in the distributor's cost performance rather than shifting standards.

The table below provides data on the distribution of stretch factors across the five stretch factor options in 2013, when the IRM was first approved, and the most recent distribution of stretch factors following the most recent stretch factor update in 2023.[8]

Distribution of Ontario Electricity Distributor Stretch Factors[9]

Percentage of Ontario Electricity Distributors	2013	2023
Stretch Factor = 0%	8.2%	31.5%
Stretch Factor = 0.15%	20.5%	27.8%
Stretch Factor = 0.30%	45.2%	31.5%
Stretch Factor = 0.45%	20.5%	5.6%
Stretch Factor = 0.60%	5.5%	3.7%
Average Stretch Factor	**0.29%**	**0.18%**

In 2013, the distribution of stretch factors was similar to a classic "bell curve." A relatively small share of utilities were assigned to either the lowest stretch factor value of 0 percent or the highest stretch factor of 0.6 percent. Nearly 85 percent of distributors were clustered in the three middle stretch factor values centered around a stretch factor of 0.3 percent. The average stretch factor value for the industry in 2013 was 0.29 percent.

The current distribution of stretch factors is very different. The share of electricity distributors with 0 percent stretch factors has nearly quadrupled between 2013 and 2023, from 8.2 percent to 31.5 percent of the industry. As a result, the approximate "top third" of cost performers in Ontario's electricity distribution industry now have a stretch factor of 0 percent. At the other end of the spectrum, the share of distributors with a stretch factor of 0.6 percent has been relatively stable, decreasing to only 3.7 percent in 2023. Consistent with these developments, the average stretch factor value for the industry has declined from 0.29 percent to 0.18 percent.

In summary, it can be seen that successive applications of incentive regulation for electricity distributors in Ontario have led to decreasing stretch factors across the industry. The experience for Ontario's gas distributors is not comparable to the electricity distribution industry since some gas distribution plan updates in Ontario have been based on Ontario's "Custom IR" option, which can differ substantively from the standard, "I-X" incentive regulation model.

In Massachusetts, the PBR experience for Boston Gas and Bay State Gas was interrupted in the early 2010s by a statewide initiative to implement revenue decoupling and other demand-side resource policies for all gas and electric utilities in the Commonwealth. The Department of Public Utilities (DPU) also ordered comprehensive cost of service filings for all energy utilities, which would serve as a consistent, statewide foundation for decoupling. These demand-side reforms,

[8] This table uses data on the percent, rather than the number, of distributors with a given stretch factor because the number of distributors in the industry declined between 2013 and 2022. Comparing distributor numbers may therefore provide a misleading indicator of the evolution of stretch factors between the two years.

[9] The columns may not add to 100 percent each year due to rounding.

as well as the need to establish new cost-based rates, made it necessary for Boston Gas and Bay State Gas to suspend their PBR plans in the early 2010s.

In 2017, PBR was reinstated for both gas and electric utilities in Massachusetts. The DPU approved PBR five-year PBR plans in 2017, 2018, 2019, 2021, and 2022. However, none of these approved plans was a successor plan to a previously approved PBR plan for the same company, so it is not possible to assess how the stretch factor in an updated PBR plan in Massachusetts compared with a stretch factor approved for the same utility company in an earlier PBR plan, with the exception of the previously referenced, initial and updated PBR plans for Boston Gas.

In Alberta, what is now termed "PBR1" approved an I-X PBR plan with a 0.96 percent productivity factor and a stretch factor of 0.2 percent, for a total X factor of 1.16 percent.

Five years later, the Alberta Utilities Commission (AUC) implemented "PBR2," with an overall X factor of 0.3 percent that did not identify explicit productivity factors or stretch factors. However, Dr. Kaufmann believes that a careful review of the evidence utilized by the AUC in PBR2 shows that the implicit productivity factor in this proceeding was 0.13 percent, and the stretch factor was accordingly 0.17 percent.

In November 2023, the AUC implemented PBR3, for the 2024-2028 period. The combined productivity factor and stretch factor in PBR3 is 0.1 percent. However, the AUC also implemented an additional 0.3 percent benefit sharing factor which was linked, at least in part, to benefits generated under the "k-bar" mechanism that the AUC implemented in PBR2 to supplement utility revenues, in addition to those provided by the approved Inflation minus X mechanism.

Overall, Dr Kaufmann believes the Ontario experience strongly supports the view that successive applications of incentive regulation typically lead to reductions in stretch factors. There is less evidence either way in either Alberta or Massachusetts, but the evidence that does exist in these jurisdictions also broadly supports this hypothesis.

45.2 Please provide an overview of the formulaic approach used by Ontario.

i. Please provide reasons why such an approach could not be applied to FBC or FEI.

Response:

For an overview of the OEB's Incentive Rate-setting frameworks and various options available to Ontario's utilities, please refer to Section 3 of Appendix B2-2 to the Application. As discussed in this appendix, the OEB has developed a set of rate-setting options to ensure that utilities have sufficient flexibility to adopt a method that best meets their needs. The utilities in Ontario can

choose to file a price cap, custom or annual index Incentive Rate-setting framework application based on their specific needs.

A price cap model, under which the rates are simply indexed to inflation, can be appropriate if the utility's investment needs during the plan's term can be sufficiently funded through a combination of growth in funding via inflation indexation and the growth in revenues via increased throughput. However, as recognized by the OEB, for utilities with significantly large multi-year or highly variable investment commitments, a custom model may be more suitable. This is because the increased funding from inflation indexation and throughput growth in the price cap model may not be sufficient to fund the utilities' large investment needs. FortisBC notes that in recent years, major electric utilities in Ontario such as Toronto Hydro or Hydro One have used the custom model to fund their significant investments.

As discussed in Section B2.3 of the Application, while all multi-year rate plans included in FortisBC's jurisdictional review share a set of common objectives, there is no "one size fit all" incentive model that can work for all utilities, and the framework adopted for each utility should be in keeping with their specific circumstances. Similar statements from regulators such as the OEB corroborate FortisBC's comment:[10]

> Although no regulatory model has yet emerged as the preferred "industry standard", other regulators are grappling with many of the same challenges facing the OEB during a period of sector evolution. Those challenges include the setting of utility remuneration to encourage efficiency and innovation, the design of rates to provide appropriate guidance to consumers regarding their own consumption and investment decisions, the mitigation of regulatory barriers to innovation and new business models, and the protection of consumers during sector transformation. The ways in which other utility regulators are addressing these issues reflect the particular institutional arrangements, market structure and broader policy framework prevailing in their jurisdictions. Although the work of other regulators is instructive, the OEB's own approach must be grounded in an appreciation of the circumstances in Ontario and of its own mandate. [Emphasis added]

Similarly, FortisBC's proposed rate plans are tailored to the specific circumstances of each utility in the context of BC's policy environment and the Companies' history of successful implementation of multi-year rate plans.

[10] https://www.oeb.ca/sites/default/files/OEB-2018-2021-business-plan.pdf; pp. 13-14.

Supplemental Information

46. Reference: Exhibit B-2, Supplemental Information p. 12

On page 12 of Exhibit B-2 FortisBC states:

> *"FortisBC has proposed the continuation of the mechanisms in the Current MRP that provide the flexibility needed over the upcoming three years to manage the impacts expected to result from the energy transition. FortisBC recognizes that the external operating environment continues to evolve…*
> *…*
> *FortisBC confirms that the Rate Framework contemplates and includes mechanisms to manage these rate impacts."*

46.1 If the Rate Framework has the needed flexibility to manage the impacts of the energy transition over the three year period 2025 to 2027, please explain why it would be incapable of doing the same over the five year period 2025 to 2029.

i. Please list or itemize any specific impacts of the energy transition that are anticipated in the period 2028 to 2029 that might limit the ability of the Rate Framework to manage rate impacts.

Response:

FortisBC considers that the Rate Framework is flexible enough to manage the rate impacts of the energy transition over the upcoming five years, but has proposed a three-year term, with the possibility to extend the Rate Framework beyond three years, in recognition of the uncertainty associated with the energy transition and feedback received from the BCUC staff and interveners, as explained in the response to ICG IR1 3.1. The formulaic approach to O&M and Growth capital (for FEI), the annual forecasting and flowing through of uncontrollable items and Clean Growth Initiatives, the provision for exogenous factors, and the earnings sharing mechanism all provide the necessary flexibility to manage the revenue requirement and rate impacts due to changes in the external environment, while maintaining a focus on cost control.

As explained in the responses to BCUC Panel Supplemental IRs (in particular the response to IRs 1 through 4 and 8), the Rate Framework is flexible enough to respond to the uncertainties and potential rate pressures created by the energy transition. The proposed Rate Framework builds off the Current MRP, which has been successful over a challenging period. The proposed Rate Framework mechanisms provide sufficient O&M and capital funding to continue to provide safe, reliable and resilient service to customers, while also maintaining a focus on cost control and supporting the Companies' need to invest in emissions reduction activities. Further, the proposed Rate Framework provides the flexibility to enable the Companies to adapt and respond to the uncertainties and evolving requirements created by the energy transition.

Regarding the possibility of extending the Rate Framework term beyond three years, please refer to the response to RCIA IR1 11.1.

Annual Review of Rates Decision

47. Reference: FortisBC Inc. 2024 Annual Review of Rates (Decision and Order G-340-23), 2.2.1 p. 17

On page 17 of Order G-34023 the BCUC states:

> *"FBC is seeking approval of a rate base MRP Application deferral account to capture regulatory costs related to the development of its next rates plan after the end of the current MRP term in 2024. FBC explains that the proposed deferral account would include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FBC forecasts costs of $0.350 million in 2023 and $1.200 million in 2024 to be recorded in the deferral account. FBC submits that it will propose an amortization period for the deferral account in a future rate-setting application."*

47.1 Please explain whether the MRP application costs forecast ($0.350 million in 2023 and $1.200 million in 2024) were based on an application for a 5 year MRP or a 3 year MRP.

Response:

The forecast of Application costs was not based on a specific term for the Application. The term of an application does not impact the application costs as those costs are incurred regardless of the term proposed.

Irrespective of a three-year or five-year term, FBC must still incur costs such as those related to external experts for the various studies and external legal support, the amount of which would not change based on the term as the level of effort to develop the studies, and the number of studies prepared, would not be impacted by the proposed term.

Further, FBC's forecast of the regulatory proceeding costs (e.g., intervener PCA, BCUC costs, etc.) was an estimate prepared prior to the regulatory timetable for this Application review process being issued, and the extent of those costs will vary due to factors such as the number of interveners participating, whether intervener evidence is filed, and the amount of regulatory process generally.

The variability of actual versus forecast regulatory costs is the primary reason that both FEI and FBC seek approval of deferral accounts for regulatory proceeding costs. It is the actual, not the forecast costs, that will ultimately be recovered from customers.

Finally, FBC considers it more appropriate to propose an amortization period once the BCUC has issued its decision on this Rate Framework Application (i.e., in the first Annual Review or rate-setting process subsequent to the decision). This is because FBC typically aligns the amortization

period with the approved Rate Framework term. FBC, therefore, considers it best to propose an amortization period when applying for approval of permanent 2025 rates, as FBC will be able to consider the rate impact of different amortization scenarios holistically with all impacts on the 2025 revenue requirement.

48. Reference: FortisBC Inc. 2024 Annual Review of Rates (Decision and Order G-340-23), 2.2.1 p. 18

On page 18 of Order G-340-23 the BCUC states:

> "The Panel approves the 2025 MRP Application deferral account, with the amortization period to be determined in a future proceeding as proposed by FBC."

48.1 Please explain whether FBC considered having the amortization period of the 2025 MRP Application deferral account determined in the 2025 - 2027 Rate Setting Framework proceeding.

Response:

Please refer to the response to RCIA IR1 47.1.