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September 20, 2023

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
Vancouver Centre II
2900 – 733 Seymour Street
Vancouver, BC
V6B 0S6

Attention: Christopher P. Weafer

Dear Christopher P. Weafer:

Re: FortisBC Energy Inc. (FEI)

Annual Review for 2024 Delivery Rates (Application) – Project No. 1599536

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On July 28, 2023, FEI filed the Application referenced above. In accordance with the amended regulatory timetable established in BCUC Order G-241-23 for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

For convenience and efficiency, FEI has occasionally provided an internet address for referenced reports instead of attaching lengthy documents to its IR responses. FEI 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,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

APPROVALS SOUGHT, PRODUCTIVITY, REVENUE REQUIREMENTS, RATE CHANGES AND FORMULA DRIVERS

1. Reference: Exhibit B-2, Page2, Page 69, Page 71, Page 72 & Page 73

2. The following deferral account approvals as described in Section 7.5:
   - Creation of rate base deferral accounts for the following regulatory proceedings:
     - 2025 Multi-year Rate Plant (MRP) Application, with the amortization period to be determined in a future proceeding;
     - 2023 Cost of Service Allocation (COSA) Study, with the amortization period to be determined in a future proceeding;
     - 2024-2027 Demand Side Management (DSM) Expenditure Plan Application, with amortization over a four-year period commencing January 1, 2024; and
     - PST Rebate on Select Machinery and Equipment, with amortization over a one-year period commencing January 1, 2024.
   - Approval of a one-year amortization period for the existing Transportation Service Report deferral account, commencing January 1, 2024.
3. A Biomethane Variance Account (BVA) Rate Rider for 2024 in the amount of $0.181 per gigajoule (GJ) as calculated in Section 10.3.1.2.
4. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2024 in the credit amount of $0.106 per GJ as set out in Table 10-5 in Section 10.3.2.
5. Fort Nelson Residential Customer Common Rate Phase-in Rate Rider for 2024 in the amount of $0.863 per GJ as calculated in Section 10.3.3.
6. The 2024 Core Market Administration Expense (CMAE) budget of $6.050 million, as set out in Appendix B, and the allocation of the CMAE between FEI's Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

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FEI is seeking approval of four new rate base deferral accounts in this Application:

- 2025 Multi-year Rate Plan (MRP) Application;
- 2023 Cost of Service Allocation (COSA) Study;
- 2024-2027 Demand Side Management (DSM) Expenditure Plan; and
- PST Rebate on Select Machinery and Equipment.

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d)	any impact on intergenerational equity	Generally, FEI recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. Please refer to Sections 7.5.1.1 to 7.5.1.3. There are no intergenerational inequities inherent in this practice.	FEI expects to return the rebates over the same period of time as the qualifying period to make the PST rebate claims. There are no intergenerational inequities in this practice.

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V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FEI generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	The account is classified as "other".

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VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M expense.	PST Rebates received from the Province of BC for claims filed by FEI for the qualifying period. Please refer to Section 7.5.1.4 for additional information.

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In the BCUC's Decision and Order G-4-18, dated January 9, 2018 (2016 COSA Decision), FEI was directed to file a comprehensive and updated COSA study for review by the BCUC five years after the release of its decision on FEI's 2016 Rate Design Application (RDA).[50] The BCUC issued its final Decision and Order G-135-18 (2016 RDA Decision) on July 20, 2018. In accordance with the 2016 COSA Decision and 2016 RDA Decision, FEI submitted its 2023 COSA Study and Revenue Rebalancing Application on July 20, 2023.

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7.5.1.1 2025 Multi-year Rate Plan (MRP) Application

1.1 Please confirm that the Commission's direct costs, notice publication costs, fees for consultants of experts, external legal counsel fees, courier and miscellaneous administrative costs, as a portion allocated to FEI, are necessary regulatory costs for the Commission to process the FEI applications for the years in which those applications are in regulatory proceedings before the Commission.

Response:

FEI confirms that the costs incurred by the BCUC are necessary. However, for clarity, the "notice publication costs, fees for consultants of experts, external legal counsel fees, and courier and miscellaneous administrative costs" described in Section 7.5.1.1 of the Application (and referenced in this question) were in reference to FEI's costs (though any such costs incurred by the BCUC could be included in the deferral account if the BCUC were to invoice FEI for those costs).

1.2 Please confirm that the Commission's costs for which FEI becomes responsible are necessary for each and every one of the FEI applications before the Commission.

Response:

Confirmed.

1.3 Please confirm that the FEI applications, for many, but not necessarily all, applications before the Commission in any given year, will involve approvals for FEI actions having benefits and consequences for FEI ratepayers for many years into the future.

Response:

Confirmed.

7.5.1.3 2024-2027 DSM Expenditures Schedule Application

1.4 Please confirm that the 2024 – 2027 Demand Side Management (DSM) Plan regulatory expenditures are aimed at approving the DSM expenditure plan for the 2024 to 2027 years.

Response:

For clarity, as part of this Application, FEI is requesting approval to establish the 2024-2027 DSM Expenditure Plan deferral account, which will capture the costs associated with the regulatory process to review the 2024-2027 DSM Expenditure Plan Application, and to amortize this new regulatory proceeding cost deferral account over four years. These regulatory proceeding costs relate to the review of FEI's 2024-2027 DSM Expenditures Application, including BCUC and intervener costs.

1.5 Please confirm that this DSM approval is absolutely necessary for the DSM expenditures to be made, and that without this approval the DSM expenditures could not be made.

Response:

Not confirmed.

The request in this Application is for a deferral account to capture the costs associated with the regulatory process for review of the 2024-2027 DSM Expenditures Plan Application and this approval is not necessary for the DSM expenditures to be made.

FEI's request for acceptance of the DSM expenditures for 2024 through 2027, which is necessary for the recovery of the DSM expenditures in rates, is the subject of a separate application to the BCUC.

1.6 Please confirm that the DSM expenditures to be made over the period 2024 to 2027 would have future benefits for the utility and its customers for multiple years after those expenditures.

Response:

FEI confirms that the DSM expenditures that are the subject of the 2024-2027 DSM Expenditures Plan Application, which is under separate review by the BCUC, would have future benefits for the utility and its customers for multiple years after the expenditures.

1.7 Please confirm that the DSM expenditures themselves will be amortized over multiple years into the future.

Response:

FEI's rate base Demand Side Management (DSM) deferral account, which captures FEI's DSM program expenditures, are amortized in rates over the approved amortization period of 10 years.

1.8 Please confirm that the DSM expenditures are amortized over multiple years into the future to match the benefits being delivered by those expenditures.

Response:

The DSM expenditures, which are the subject of the 2024-2027 DSM Expenditures Plan Application and under separate review and acceptance by the BCUC, are captured in FEI's existing DSM deferral accounts and are amortized over 10 years in order to match the benefits of DSM measures with the costs. In contrast, the benefits associated with preparing the 2024-2027 DSM Expenditures Plan application itself are expected to last for the period of four years (i.e., the time period that the 2024-2027 DSM Plan will be in place).

1.9 Please explain why FEI expects that the benefits for approvals of DSM expenditures will occur over the period of 2024 – 2027.

Response:

The 2024-2027 DSM Expenditure Plan deferral account discussed in Section 7.5.1.3 of the Application does not capture any costs related to the DSM expenditures themselves and, as such, FEI does not consider it reasonable to amortize the expenditures over the period of time over which the DSM expenditures would provide benefits.

Rather, as the purpose of the deferral account is to capture only those costs related to the regulatory review of the 2024-2027 DSM Plan application, the more appropriate period over which to recover the costs is 2024-2027. Generally, FEI recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. In this case, FEI is requesting to amortize the regulatory proceeding costs of over four years starting in 2024 to match the time period that the 2024-2027 DSM Plan will be in place.

7.5.1.2 2023 Cost of Service Allocation (COSA) Study

1.10 Please confirm that the Cost of Service Allocation Study (COSA) is aimed at providing the base information to, among other things, inform future rate designs for FEI's rate classes.

Response:

Not confirmed. The purpose of the COSA study is to inform the performance of the *current* rate design for FEI's rate classes and to provide information on if there is a reasonable balance

between the allocated costs and revenue recovery in each rate class. A COSA study does not necessarily mean a new future rate design is to be followed after the study is complete.

1.11 Please confirm that the previous COSA Study was initiated in 2016 and FEI had used this study to inform its rate designs initiated in applications in 2016.

Response:

Confirmed. FEI prepared and filed the previous COSA study as part of the 2016 COSA and Rate Design Application. The COSA study and rate design formed one application.

1.12 Please confirm that the rate designs could not proceed without Commission approval, and that the applications for the COSA and the rate designs were a necessary part of proceeding with those designs.

Response:

FEI confirms that it must apply for BCUC approval for revenue rebalancing and to make changes to its rate design.

1.13 Please confirm that the benefits for customers of the COSA and related rate designs are realized by the customers during the future periods that the rate designs are in effect, and that these future periods can extend multiple years into the future after the rate designs are approved.

Response:

Confirmed.

1.14 Please explain whether or not the Revenue Rebalancing Application filed July 2023 along with the COSA Study is, in effect, a rate design application.

Response:

No, FEI is not proposing to change its rate design as part of the 2023 Cost of Service Allocation and Revenue Rebalancing application. A revenue rebalancing application is not the same as a rate design application. Undertaking a COSA study does not necessarily mean that rate design changes will be requested (and in fact, depending on the results of the COSA study, no action may be required at all if the results show that all rate classes are within the Revenue to Cost Ratio range of reasonableness). This was recognized by the BCUC in their decision on FEI's 2016 Rate Design Application:[1]

> The Panel agrees with FEI's views on the timing of the next comprehensive rate design and notes that the next rate design application should be filed by FEI depending on the results of the next COSA study as well as consideration of any other information indicating that rate design changes should be explored. If FEI determines that *rate design and/or rebalancing* should take place based on the results of the next COSA study or any other information, the Panel expects that FEI will *file such rate design and/or rate rebalancing proposals together with the COSA study*. [Emphasis Added]

1.15 Please confirm that the COSA Study deferral account application does not incorporate the regulatory costs for the Revenue Rebalancing Application.

Response:

Not confirmed. The 2023 COSA Study and Revenue Rebalancing Application are part of the same regulatory proceeding. The requested deferral account will record all of the regulatory proceeding costs for the review of this application.

1.16 Please explain why FEI's new Revenue Rebalancing Application regulatory costs are not the subject of a deferral account request for approval.

Response:

Please refer to the response to CEC IR1 1.15.

[1] Decision and Order G-135-18, pp. 83

1.17 Please confirm that the Revenue Rebalancing rate setting consequences are realized by customers over multiple years into the future, until such time as the next Revenue Rebalancing rate setting is applied for.

Response:

Confirmed.

1.18 Please provide the date of initiation for the last Revenue Rebalancing application, and the date for the Commission approved outcome for that application.

Response:

The 2016 Rate Design Application (RDA) included a COSA study, revenue rebalancing, and a comprehensive rate design component.

2. Reference: Exhibit B-2, Page 4

> Of the approximate $7.3 million in formula O&M savings realized in 2022, approximately $2 million are due to savings achieved as the result of productivity initiatives, including the Willingdon Park Redesign, Paperless Billing Customer Campaigns, and Operational Field Excellence[3], which were described in the Annual Review for 2023 Delivery Rates. Additionally, approximately $3 million of the overall O&M savings are due to estimated general overall labour savings. The remaining savings are the result of various factors, including: $0.3 million in lower spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security (refer to Section 6.2.1 for further details); $0.4 million of lower employee expenses, $0.5 million of lower spending on Connect to Gas rebates due to lower customer participation; and savings due to general timing of expenditures. While some of the savings are one-time in nature (e.g., required time to fill vacancies from turnover), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

Page 4

> As described in FEI's Annual Review for 2022 Delivery Rates, in 2021, FEI and FortisBC Inc. (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying productivity initiatives. Following is a summary of these productivity initiatives.

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2.1 Please confirm that these savings are calculated in regard to the 2022 realized expenses versus the approved forecast 2022 expenses.

Response:

The $7.3 million in formula O&M savings realized in 2022 is determined by comparing the 2022 actual formula O&M expenses versus the 2022 approved formula O&M (i.e., the component of O&M that is subject to the earnings sharing mechanism).

2.2 Please provide the number of vacancies in approved staff positions for each of the last 5 years and the average time to fill a vacancy in each of the same years.

Response:

Please see the table below which provides the number of vacancies for each of the past five years and the average number of days to fill the vacancies. FEI did not track the time to fill a position prior to 2020.

	2018	2019	2020	2021	2022
Vacancies (FTEs)	71	113	134	150	176
Avg. Time to Fill a position (Days)	n/a	n/a	57	57	55

2.3 Please provide any models of the productivity improvement projects which the group of senior managers and directors from different parts of the organization use to identify and guide the productivity improvement projects.

Response:

The Working Group of senior managers and directors from different parts of the organization did not use any models of productivity improvement projects and instead relied primarily on their collective experience and understanding of the various functions and processes within the Company. The group then worked collaboratively in identifying productivity improvement projects to pursue.

2.4 Please identify the metrics for the potential benefits of each of the productivity initiatives so that it is clear what productivity is intended to be achieved.

Response:

Overall, in general, the initiatives listed in the Application all provide productivity benefits as measured primarily in financial cost savings (i.e., quantitative benefits). Additionally, where applicable, some of the initiatives also provide other benefits which are qualitative in nature.

The following table describes the productivity initiatives and the benefits, both quantitative and qualitative.

Productivity Initiative	Quantitative Benefits	Qualitative Benefits
Willingdon Park Redesign	O&M cost savings	Improved workspace design which enhances collaboration and communication.
Operational Field Excellence	O&M cost savings	General goal of operational efficiency by better prioritization of emergency repairs, improved work planning, and reducing low value activities such as wait times and pulled work orders. For Leak Categorization processes, other benefits include enabling improved decision-making, improving field resource utilization, and improved customer service.

Productivity Initiative	Quantitative Benefits	Qualitative Benefits
Methane Lead Detection	Potentially more cost-effective approach – initiative is in investigation stage. Potential reduction of resource hours required to complete associated survey work. This includes tangible hours for employees, and overall length of time for contractor resources.	May allow for more timely identification and resolution of leaks.
Data Analytics	O&M cost savings – initiative in initial deployment stage	Provides four key capabilities: faster software implementation; easier access to data and data analytics assets; improved governance of data and analytic assets; and the ability to develop data and analytics organizational talent.
Robotic Process Automation	O&M costs savings	For automation of Finance processes - faster and more timely processing of activities, allowing for earlier and increased analysis and review time.
Paperless Billing Customer Campaigns	O&M cost savings	Convenience of customers receiving their bills electronically and the environmental considerations of less paper and physical transport of the bills.
Other smaller initiatives – mobile enabling applications; automated patching; other IS initiatives; customer service initiatives	O&M cost savings – smaller scale	Metrics include improved consistency, reliability and comprehension of data collected, and the reduced risk of errors. For the Customer Service initiatives, benefits considered include improved customer experience; in particular, first contact resolution.

2.5 Please provide whatever guidelines the senior management and directors use to ensure that their process for managing project initiatives is optimized.

Response:

The Working Group of senior managers and directors worked with the applicable business areas with a primary focus on reviewing and identifying productivity improvement projects. An area of focus for potential productivity opportunities was initiatives that offered financial and customer service benefits and leveraged technology and innovation as enablers. The implementation of the individual initiatives is led and managed by project leads and/or the business areas impacted, following appropriate project management guidelines. General guidelines for managing initiatives, where applicable, include monitoring the project's status (i.e., scope, schedule, resources and budget), with action(s) taken as required. Post implementation, where appropriate, includes discussions of lessons learned and the tracking of benefits realized.

2.6 Please review the following numerical summary of what FEI has provided about its Productivity Initiatives.

FORTISBC ENERGY INC PRODUCTIVITY IDENTIFIED PROJECTS & QUANTIFIED SAVINGS			
Future Years	Future Savings	Productivity Projects 2022 Savings	
?	?	$400,000	Operational Field Excellence
?	?		Methane Leak Detection
2025	$375,000		Data Analytics
2024	$75,000		Robotics Process Automation
?	?	$25,000	Paperless Billing
?	?		Other
?	?		mobile enabling
?	?		automated patching
?	?		other I/S initiatives
?	?		customer service initiatives
		$6,875,000	Unknown Remaining
	$450,000	$7,300,000	
% Quantified 6% for 2022 & 12% for 2022 plus the Future			
Exhibit B-2, Pages 1 to 7			

Response:

FEI has reviewed the CEC's numerical summary. Please refer to the response to CEC IR1 2.7.

2.7 Please verify and/or correct the CEC summary above of the FEI Productivity Initiatives Identified and Quantified.

Response:

The CEC's summaries of FEI Productivity Initiatives Identified and Quantified in the preamble in CEC IR1 2.6 are not correct. FEI provides the following table below which reconciles the $7.3 million formula savings achieved in 2022 and breaks down the savings between Productivity Initiatives and Other reasons contributing to the savings. FEI also provides the estimated savings for 2023 and 2024 (i.e., the remainder of the MRP term).

Cumulative FEI Formula O&M Savings	Actual 2022	Estimated 2023	Estimated 2024	Estimated >2024
Productivity Initiatives Specific				
Willingdon Park Redesign	$ 1.0	$ 1.0	$ 1.0	$ 1.0
Operational Field Excellence	0.9	0.9	0.9	0.9
Methane Lead Detection	-	-	-	
Data Analytics	-	-	-	0.4
Robotic Process Automation	-	-	0.1	0.1
Paperless Billing Customer Campaigns	0.4	0.4	0.4	0.4
Other Smaller Initiatives	-	-	-	-
Subtotal	**$ 2.3**	**$ 2.3**	**$ 2.4**	**$ 2.8**
Other				
Overall Labour Savings	$ 2.8	n/a	n/a	n/a
Employee Expenses	0.4	n/a	n/a	n/a
System Operations, Integrity and Security	0.3	n/a	n/a	n/a
Connect to Gas Rebates	0.5	n/a	n/a	n/a
General Timing of Expenditures	1.0	n/a	n/a	n/a
Subtotal	**$ 5.0**	**$ -**	**$ -**	**$ -**
Total Cumulative Formula O&M Savings	**$ 7.3**	**$ 2.3**	**$ 2.4**	**$ 2.8**

FORTISBC ENERGY INC CLAIMED SAVINGS & QUANTIFICATIONS		
Claimed	Quantified	
$2,000,000		O&M Savings Quantified
	?	Willingdon Park Redesign
	$25,000	Paperless Billing
	$400,000	Operational Field Excellence
$3,000,000		O&M Savings
		General Labour Savings
$1,200,000		O&M Savings Quantified
	$300,000	Lower Spending vs Formula
	$400,000	Systems Operations Integrity & Security
	$500,000	Lower Connect to Gas Rebates
$1,100,000		O&M Savings Unquantified
$7,300,000	$1,625,000	O&M Savings 2022 Claimed & Quantified
% Quantified 22%		
Exhibit B2, Pages 1 to 7		

2.8 Please verify and/or correct the CEC alternative summary of FEI Claimed Productivity Savings and Quantification.

Response:

Please refer to the response to CEC IR1 2.7.

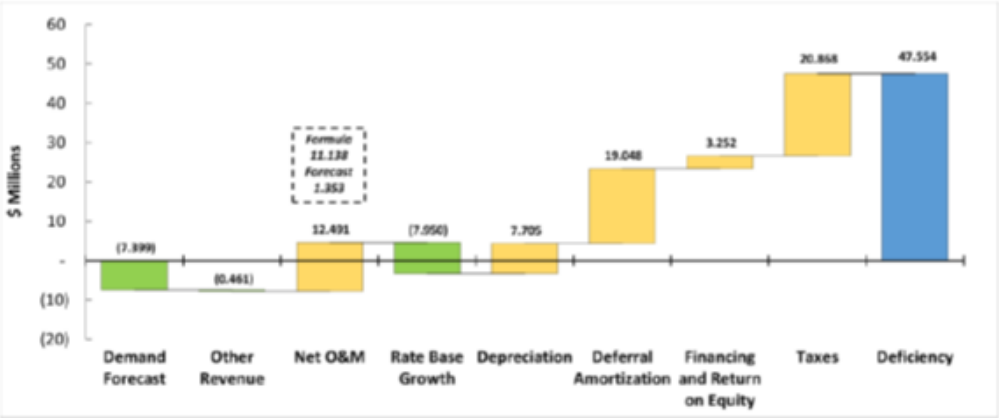
2.9 Please verify that the $7,300,000 in claimed productivity savings represents the difference between the forecast costs and the realized costs.

Response:

Please refer to the response to CEC IR1 2.1.

3. Reference: Exhibit B2- Pages, 8, 9, 10, 13, 60, 81, 104, 105, 123

Figure 1-1: 2024 Delivery Revenue Deficiency ($ millions)



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3.1 Please confirm that the demand forecast is lower by 1.6 PJ or 0.72% of total demand.

Response:

Confirmed. As shown in Figure 3-1 of the Application, the 2024 demand is forecast to be 220.2 PJ which is 1.6 PJ lower than the 2023 Approved demand of 221.8 PJ. 1.6 PJ is 0.72 percent of 221.8 PJ.

3.2 Please confirm that the forecast for LNG-related customer demand is the primary cause of the reduction in demand, and that this reduction is in the category of transportation customers total reduction of 3.466 PJ and the related revenue reduction is $6,124,000 from the total revenue of $86,799,000.

3.2.1 If the LNG customer demand is not in the transportation customer category, please provide the specific LNG customer reduction and the related revenue reduction.

3.2.2 Please provide the LNG-specific demand reduction and revenue reduction and, if this is in the transportation customer category, please provide the other transportation customer related demand reduction and revenue reduction.

3.2.3 Please provide the LNG-specific demand reduction and revenue reduction and please explain if this is in the sales customer category; and

please provide the other sales customer related demand increase and related revenue increase or reduction as the case may be.

Response:

As explained in Section 1.5.1 of the Application, the reduction in forecast RS 46 LNG demand is one of the primary contributors to the 2024 forecast decrease in demand of 1.6 PJ (RS 22 large volume transportation bypass customers also contribute to the reduction). For 2024, FEI is forecasting the RS 46 LNG sales to decrease by 2,185 TJ from 2023 Approved, followed by a reduction of approximately 1,525 TJ from RS 22 bypass customers.

As presented in Schedule 16 in Section 11 of the Application, the demand and revenue from RS 46 LNG customers are not included as part of the transportation customer category. RS 46 is considered a special rate, which was set in accordance with Order in Council (OIC) 557/2013 and further amended through OIC 749/2014 and OIC 162/2017. Accordingly, FEI has consistently presented RS 46 demand and revenue as part of the sales customer category.

Please refer to Table 1 below which provides a breakdown of the change in demand and revenue between 2023 Approved and 2024 Forecast by rate class and between sales and transportation customers, as presented in Schedule 16 of Section 11 of the Application.

Table 1: Breakdown of Change in Demand and Revenue between 2023 Approved and 2024 Forecast by Rate Class and between Sales and Transportation Customer Categories

	Change between 2023 Approved and 2024 Forecast		
	Demand (TJ)	Revenue at existing rates ($000s)	Reference
Sales Customers			
Rate Schedule 1	489	(217,166)	
Rate Schedule 2	475	(74,359)	
Rate Schedule 3	1,232	(59,424)	
Rate Schedule 4	12	(392)	
Rate Schedule 5	1,043	(20,976)	
Rate Schedule 6	(3)	(77)	
Rate Schedule 7	795	(11,764)	
Rate Schedule 46	(2,185)	(28,943)	
Subtotal	**1,858**	**(413,101)**	**Section 11 - Schedule 16, Line 2 and Line 7, Column 6**
Transportation Customers			
Rate Schedule 23	(267)	(1,179)	
Rate Schedule 22 (Non-bypass)	(704)	(3,161)	
Rate Schedule 25 (Non-bypass)	(526)	(1,206)	
Rate Schedule 27	(412)	(778)	
Rate Schedule 22 (Bypass)	(1,525)	-	
Rate Schedule 25 (Bypass)	(46)	(3)	
Byron Creek	1	-	
VIGJV	13	203	
Subtotal	**(3,466)**	**(6,124)**	**Section 11 - Schedule 16, Line 3 and Line 9, Column 6**
Total	**(1,608)**	**(419,225)**	**Section 11 - Schedule 16, Line 4 and Line 7 + Line 9, Column 6**

3.3 Please confirm that the lower forecast of demand and revenue of LNG-related customers is offset by increased net demand from other sales customers of 1.858 PJ and a related revenue decrease of $413,101,000.

Response:

As discussed in the response to CEC IR1 3.2, the RS 46 LNG demand and revenue are included in the sales customers category. Thus, the net increase of 1.858 PJ and revenue decrease of $413.101 million includes the decrease due to RS 46 LNG customers.

FORTISBC ENERGY INC. — FEI Annual Review for 2024 Rates - July 28, 2023 — Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s) — Schedule 16

Particulars	2023 Approved	2024 Forecast at 2023 Approved Rates	2024 Forecast Revised Revenue	2024 Forecast at Revised Rates	Change	Cross Reference
(1)	(2)	(3)	(4)	(5)	(6)	(7)
ENERGY VOLUMES						
Sales Volume (TJ)	160,101	161,958		161,958	1,858	
Transportation Volume (TJ)	61,672	58,206		58,206	(3,466)	
	221,773	220,165	-	220,165	(1,608)	Schedule 17, Line 23, Column 3
REVENUE AT EXISTING RATES						
Sales	$ 2,162,318	$ 1,749,217	$ -	$ 1,749,217	$ (413,101)	
Deficiency (Surplus)	-	-	44,251	44,251	44,251	
Transportation	86,799	80,675	-	80,675	(6,124)	
Deficiency (Surplus)	-		3,303	3,303	3,303	
Total	2,249,117	1,829,892	47,554	1,877,446	(371,671)	Schedule 19, Line 29, Column 8
COST OF ENERGY	1,170,773	744,149	-	744,149	(426,624)	Schedule 18, Line 23, Column 3
MARGIN	1,078,344	1,085,743	47,554	1,133,297	54,953	
EXPENSES						
O&M Expense (net)	292,666	305,157	-	305,157	12,491	Schedule 20, Line 28, Column 4
Depreciation & Amortization	326,852	353,605	-	353,605	26,753	Schedule 21, Line 15, Column 3
Property Taxes	79,144	83,359	-	83,359	4,215	Schedule 22, Line 8, Column 3
Other Revenue	(42,018)	(42,479)	-	(42,479)	(461)	Schedule 23, Line 12, Column 3
Utility Income Before Income Taxes	421,700	386,101	47,554	433,655	11,955	
Income Taxes	51,748	55,563	12,838	68,401	16,653	Schedule 24, Line 13, Column 3
EARNED RETURN	$ 369,952	$ 330,538	$ 34,716	$ 365,254	$ (4,698)	Schedule 26, Line 5, Column 7
UTILITY RATE BASE	$ 5,943,434	$ 5,815,727		$ 5,815,903	$ (127,531)	Schedule 2, Line 30, Column 3
RATE OF RETURN ON UTILITY RATE BASE	6.23%	5.68%		6.28%	0.05%	Schedule 26, Line 5, Column 6

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3.4 Please confirm that the deficiencies in the sales customer category of $44,251,000 is the revenue required from sales rates to meet the utility revenue requirements.

Response:

Confirmed.

3.5 Please confirm that the deficiency in the transportation customers category of $3,303,000 is the revenue required from the transportation customers to meet the utility revenue requirements.

Response:

Confirmed.

3.6 Please confirm that Other Revenue contains the late payment charges of $3,607,000 and the application charges of $1,797,000.

Response:

Confirmed. Please refer to Section 5 of the Application.

3.7 Please explain what the largest item in Other Revenue of $37,075,000 is derived from, and whether or not there is any change in the rates applicable for earning this other income.

Response:

FEI notes that the total 2024 Forecast for Other Revenue (as shown in Schedule 16 in the preamble to this IR as well as in Table 5-1 of the Application), is $42.479 million. FEI assumes that the CEC has excluded Late Payment Charges of $3.607 million and Application Charges of $1.797 million to arrive at the $37.075 million referenced in this question.

As shown in the breakdown of Other Revenue provided in Table 5-1 of the Application, the largest item contributing to the Other Revenue forecast is the LNG capacity assignment amount of $18.039 million. As explained in Section 5.4 of the Application, the LNG capacity assignment is related to the transfer of allocated costs to cost of gas for the Mt. Hayes LNG facility, which has a dual purpose of serving as a gas supply storage facility and as a transmission facility. The allocation of the Mt. Hayes LNG facility between delivery margin and cost of gas was reviewed and approved by the BCUC as part of FEI's 2016 Rate Design Application[2]. The amount of LNG

[2] Approved by Order G-4-18.

Capacity Assignment Other Revenue is consistent with 2023 Approved, therefore, it does not contribute to the 2024 revenue deficiency or delivery rate increase.

Particulars (1)	2023 Approved (2)	2024 Forecast (3)	Change (4)	Cross Reference (5)
Late Payment Charge	$ 3,385	$ 3,607	$ 222	
Application Charge	2,020	1,797	(223)	
NSF Returned Cheque Charges	28	28	-	
Other Recoveries	288	288	-	
SCP Third Party Revenue	13,286	13,320	34	
NGT Tanker Rental Revenue	926	1,021	95	
NGT Overhead and Marketing Recovery	273	341	68	
Biomethane Other Revenue	512	762	250	
LNG Capacity Assignment	18,039	18,039	-	
CNG & LNG Service Revenues	3,261	3,276	15	
Total	$ 42,018	$ 42,479	$ 461	

3.8 Please explain what has caused the decrease in application charges.

Response:

Application Charges are primarily driven by existing customer reconnections (i.e., move-ins), and to a lesser extent, new customer connections. Consistent with past practice, the Application Charge is forecast based on the actuals from three prior years, i.e., 2020, 2021, and 2022. There has been a decline in move-ins (and move-outs) in recent years which led to a decrease in the 2024 Forecast Application Charges.

3.9 Please confirm whether or not the biomethane Other Revenue is coming directly from biomethane using customers and/or is being collected from all customers related to acquisition of biomethane not sold directly to customers.

Response:

Including a credit for biomethane costs in Other Revenue (Biomethane Other Revenue) is the mechanism that FEI uses to reclassify earned return and income taxes related to biomethane assets to the Biomethane Variance Account (BVA) so that these revenue requirement costs are borne by biomethane customers.

Biomethane assets are included in FEI's rate base. These assets increase FEI's delivery revenue requirement by way of depreciation, net salvage, property tax, earned return, and income taxes. Each year when FEI files for delivery rate changes through the annual review process, FEI

reclassifies these aforementioned costs from FEI's delivery margin to the BVA by crediting the delivery revenue requirement and debiting the BVA. Biomethane asset depreciation is credited in Section 11, Schedule 7.2, Line 36; net salvage is credited in Section 11, Schedule 10.2, Line 23; property tax is credited in Section 11, Schedule 22, Line 7, and earned return and income tax related to biomethane assets in rate base is credited as Biomethane Other Revenue (Section 11, Schedule 23, Line 8), all with offsetting debits to the BVA.

3.10 Please provide information the rate increases for all other revenue categories.

Response:

As the 2024 Forecast for Other Revenue is approximately $0.461 million higher than 2023 Approved, the increased 2024 Forecast is helping to offset the 2024 revenue deficiency and is providing an overall delivery rate benefit of 0.04 percent when compared to the 2023 Approved delivery rates. Please refer to Table 1 below for the 2024 delivery rate impact by each category of Other Revenue when compared to the 2023 Approved.

Table 1: Delivery Rate Benefits by Other Revenue Category

	2023 Approved ($ million)	2024 Forecast ($ million)	Change ($ million)	2024 Delivery Rate Impact / (Benefit) %
Late Payment Charge	$ 3.385	$ 3.607	$ 0.222	-0.02%
Application Charge	2.020	1.797	(0.223)	0.02%
NSF Returned Cheque Charges	0.028	0.028	-	-
Other Recoveries	0.288	0.288	-	-
Tilbury Insurance Proceeds	-	-	-	-
NGT Related Recoveries	4.460	4.638	0.178	-0.02%
Biomethane Other Revenue	0.512	0.762	0.250	-0.02%
SCP Third Party Revenue	13.286	13.320	0.034	0.00%
LNG Capacity Assignment	18.039	18.039	-	-
Total	**$ 42.018**	**$ 42.479**	**$ 0.461**	**-0.04%**

1.5.3 Operations and Maintenance (O&M) Expense (Section 6)

FEI establishes the majority of its O&M costs by formula during the MRP term. For 2024, the formula incorporates a net inflation factor of 3.854 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers,[5] for a total increase in formula O&M of $13.259 million[6] (4.4 percent) from 2023 Formula O&M. O&M forecast outside of the formula is increasing by $2.301 million[7] (4.2 percent) compared to 2023 Approved. The 2024 increase in total O&M expense net of capitalized overhead and Biomethane O&M transferred to the BVA is $12.491 million.

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3.11 Figure 1.1 shows the formula increase at $11,138,000 with the forecast of $1,353,000 for a total of $12,491,000. Section 1.5.3 shows the increase in formula being $13,259,000 and the forecast increasing by $2,301,000 with an explanation that the net O&M increase is $12,491,000 and is explained by capitalized overhead and Biomethane O&M transferred to the BVA. Please explain and quantify the capitalized overhead and explain and quantify the biomethane O&M transferred to the Biomethane Variance Account (BVA).

Response:

Please refer to Table 1 below for the reconciliation between gross O&M increases (i.e., $13.259 million for formula O&M and $2.301 million for forecast O&M) and net O&M increases (i.e., $11.138 million for formula O&M and $1.353 million for forecast O&M).

FEI notes that as part of the 2020-2024 MRP Decision and Order G-165-20, the BCUC approved a capitalized overhead rate for FEI of 16 percent, resulting in a difference between gross and net O&M. Further, all biomethane related costs and revenues are approved to be transferred to the BVA with the balance to be recovered from customers through the Biomethane Energy Recovery Charge (BERC) and the BVA Rate Rider. As such, the biomethane O&M is transferred out of net O&M.

Table 1: Reconciliation of Change in Total Gross O&M and Total Net O&M between 2023 Approved and 2024 Forecast

Line	($000s)	Reference	2023 Approved	2024 Forecast	Change
1	Total Gross Formula O&M	Table 6-1, Line 1	299,302	312,561	13,259
2	Less: Capitalized Overhead (16%)	Line 1 x 0.16	(47,888)	(50,010)	(2,121)
3	**Total Net Formula O&M**	**Line 1 + Line 2**	**251,414**	**262,551**	**11,138**
4					
5	Total Gross Forecast O&M	Table 6-1, Line 2	55,345	57,646	2,301
6	Less: Capitalized Overhead (16%)	Line 5 x 0.16	(8,855)	(9,223)	(368)
7	Less: O&M Transferred to Biomethane BVA	Table 6-8, Line 14	(5,237)	(5,817)	(580)
8	**Total Net Forecast O&M**	**Line 5 + Line 6 + Line 7**	**41,253**	**42,606**	**1,353**
9					
10	**Total Net O&M**	**Line 3 + Line 8**	**292,666**	**305,157**	**12,491**

1.5.4 Rate Base Growth (Section 7)

The 2024 rate base is forecast to decrease by approximately $127.531 million when compared to the 2023 Approved rate base, which results in a decrease to the 2024 Forecast earned return and the 2024 deficiency of approximately $7.950 million. The decrease in rate base is primarily due to decreases in the mid-year balance of FEI's deferral accounts by approximately $214.107 million and working capital by $38.619 million when compared to 2023 Approved. The decrease in the mid-year balance of FEI's deferral accounts is primarily due to the credit balances of the MCRA and CCRA, driven by strong mitigation performance by FEI at the end of 2022 as well as favourable forward commodity gas prices. The decreases in rate base due to deferral accounts and working capital are partially offset by the increase in FEI's plant in service by $134.127 million[6], primarily due to the additions of a number of CPCN and Major projects, including the Tilbury 1A Expansion, Inland Gas Upgrades (IGU), Gibsons Capacity Upgrade (GCU), Lower Mainland Intermediate Pressure System Upgrades (LMIPSU), and Pattullo Gasline Replacement (PGR) projects.

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3.12 Please explain the FEI strong mitigation performance in regard to the MCRA and CCRA credit balances.

Response:

To clarify, FEI's natural gas supply portfolio mitigation activities and associated revenues are captured in the MCRA, and do not impact the CCRA.

Regional pricing dynamics and strong western gas prices led to substantial mitigation revenue and recoveries for FEI during the November 2022 through March 2023 winter period. These dynamics included increased and sustained demand for thermal power generation in the Pacific Northwest as well as strong natural gas demand for residential, commercial and industrial use due in part to extreme cold weather conditions. This resulted in the entire western side of the continental United States, including market centres supplying Washington, Oregon and California, carrying a premium during the winter from November 2022 to March 2023.

3.13 Please quantify the favourable forward commodity gas prices and the impact that these have on the rate base.

Response:

The CCRA captures price-related variances due to differences between the FEI baseload commodity portfolio purchase costs and the associated recoveries at the approved commodity rate. Quantity-related variances, caused by differences between the recorded customer consumption and the normalized demand used in establishing the baseload requirements and recovery rates, are captured in the MCRA.

On a quarterly basis, as required under the BCUC guidelines for gas cost rate setting (the Guidelines)[3], FEI submits a gas cost report to the BCUC wherein the CCRA and MCRA deferral account balances, at the existing rates, are reported. The CCRA deferral account imbalances are managed via changes to the commodity rate; the commodity rate is subject to quarterly review and resetting, pursuant to BCUC approval.

Table 1, attached below, summarizes the commodity rate change approved effective July 1, 2023, as filed in the FEI 2023 Second Quarter Gas Cost Report (2023 Q2 Gas Cost Report), and the commodity rate change proposed effective October 1, 2023, as recently filed in the FEI 2023 Third Quarter Gas Cost Report (2023 Q3 Gas Cost Report), dated September 6, 2023.

Table 1 - CCRA Deferral Account - Commodity Rate Change Summary
Approved July 1, 2023 and Proposed October 1, 2023 Changes to the Commodity Rate

Particulars		2023 Q2 Gas Cost Report	2023 Q3 Gas Cost Report
CCRA 12-Month Prospective Period		Jul 2023 - Jun 2024	Oct 2023 - Sept 2024
Projected Opening CCRA Balance (After-Tax)	*($M)*	($23.2)	($20.7)
Forecast CCRA Portfolio Average Cost of Commodity	*($/GJ)*	$2.169	$2.420
Commodity Rate in Effect Prior to Approved / Proposed Decrease	*($/GJ)*	$4.159	$3.159
Commodity Rate in Effect After Approved / Proposed Decrease	*($/GJ)*	$3.159	$2.230
Tested Full Flow-Through			
Amortization of Projected Opening CCRA Balance	*($/GJ)*	($0.2166)	($0.1896)
Recovery of Forecast CCRA Costs for Prospective Period	*($/GJ)*	($1.9896)	($0.7392)
Total Tested Full Flow-Through Decrease	*($/GJ)*	($2.206)	($0.929)
Approved / Proposed Flow-Through Decrease	*($/GJ)*	($1.000) [(a)]	($0.929)
Remaining Over Recovery Embedded in Commodity Rate	*($/GJ)*	**$1.206**	**-**

Notes: (a) Commodity rate change cap applied consistent with the Guidelines.
Slight differences in totals due to rounding.

As reflected in Table 1, the July 1, 2023 commodity rate decrease requested in the 2023 Q2 Gas Cost Report, and approved pursuant to Order G-148-23, was a partial flow-through of the forecast over recovery of CCRA costs, including the opening CCRA balance, for the 12-month prospective period. The remaining over recovery amount of $1.206/GJ embedded in the commodity rate

[3] The BCUC established guidelines for gas cost rate setting in Letter L-5-01, dated February 5, 2001, and further modified the guidelines pursuant to Letter L-40-11, dated May 19, 2011, and Letter L-15-16, dated June 16, 2016.

effective July 1, 2023 is the primary driver of the CCRA credit balances forecast within the 2023 Q2 Gas Cost Report, and were used as inputs to the Annual Review for 2024 Delivery Rates Application.

As further reflected in Table 1, FEI is requesting an October 1, 2023 commodity rate decrease within its 2023 Q3 Gas Cost Report. The requested decrease is based on a full flow-through of the forecast over recovery of CCRA costs, including the opening balance, for the 12-month prospective period.

In terms of the impact to FEI's rate base, as reflected in Section 11, Schedule 11, Line 3, Column 10, the 2024 mid-year forecast of the CCRA is a credit of $32.414 million which is a reduction of approximately $167.514 million compared to the 2023 Approved balance. The associated cost of service impact due to this reduction in rate base is a credit of approximately $12.611 million to the 2024 revenue deficiency, which is equivalent to a delivery rate savings (reduction to the delivery rate) of 1.2 percent when compared to 2023 Approved.

3.14 Please confirm that net decrease in the rate base of $7,950,000 reduces the revenue requirement for earned return on the rate base and therefore the revenue requirement from rates for customers.

Response:

Confirmed. However, FEI notes that the net decrease in rate base is $127.531 million from 2023 Approved to 2024 Forecast, not $7.950 million. The $7.950 million is the equivalent reduction in FEI's earned return due to the reduction in rate base, thus reducing the requirement as well as rates for customers in 2024.

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CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s) — Schedule 5

Particulars (1)	2024 Formula (2)	Cross Reference (3)
CAPEX		
Growth Capital Expenditures	$ 54,639	Schedule 4, Line 10, Column 5
Forecast Capital Expenditures	230,819	Schedule 4, Line 18, Column 5
Total Capital Expenditures	$ 285,458	
Special Projects and CPCN's		
Tilbury 1A Expansion	$ 3,959	
LMIPSU CPCN	6	
Inland Gas Upgrade	20,721	
Transmission Integrity Program (CTS TIMC)	63,107	
Pattullo Gasline Replacement	153	
FEI AMI CPCN	55,000	
Total Capital Expenditures	$ 142,946	
Total Capital Expenditures	$ 428,404	
RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT		
Regular Capital Expenditures	$ 285,458	Line 4
Add - Capitalized Overheads	59,233	Schedule 20, Line 27, Column 4
Add - AFUDC	9,526	
Gross Capital Expenditures	354,217	
Change in Work in Progress	20,404	
Total Regular Additions to Plant	$ 374,621	
Special Projects and CPCN's Capital Expenditures	$ 142,946	Line 13
Add - AFUDC	7,166	
Gross Capital Expenditures	150,112	
Change in Work in Progress	(87,927)	
Total Special Projects and CPCN Additions to Plant	$ 62,185	
Grand Total Additions to Plant	$ 436,806	

1

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Particulars (1)	Growth CapEx (2)	Other CapEx (3)	Forecast CapEx (4)	Total CapEx (5)
Inflation Indexed Capital Growth				
2023 Unit Cost Growth Capital	$ 4,205			
2024 Net Inflation Factor	3.854%			
2024 Unit Cost Growth Capital	$ 4,367			
2024 Gross Customer Additions	15,000			
2024 Inflation Indexed Growth Capital	$ 65,505			$ 65,505
2022 Growth Capital Customer True-Up				(14,254)
2024 System Extension Fund				1,000
2024 Growth CIAC				2,388
2024 Inflation Indexed Gross Growth Capital				$ 54,639
Capital Tracked Outside of Formula				
Pension & OPEB (Growth Capital Portion)			$ 871	
Biomethane Assets			43,068	
NGT Assets			5,000	
Sustainment Capital			130,628	
Other Capital			51,252	
Sub-total			$ 230,819	230,819
Total Capital Expenditures Before CIAC				$ 285,458

3

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5 3.15 Please confirm that the -$14,254,000 true up for the prior years growth capital for
6 customers represents a formula forecast higher in the prior year than the formula
7 forecast for the same period.
8

Response:

Not confirmed.

FEI notes that as discussed in Section 7.2.1 of the Application, FEI's approved growth capital formula is calculated based on the forecast of gross customer additions. The purpose of the true-up, as approved as part of the MRP Decision and Order G-165-20[4], is to eliminate any forecasting errors in the forecast of gross customer additions from two years prior[5]. It is not a true-up of prior year formula growth capital.

As shown in Table 7-2 of the Application (i.e., Lines 11 to 16), the 2022 Forecast of gross customer additions was 3,523 higher than 2022 Actual; as such, based on the 2022 unit cost of growth capital of $4,046, the 2024 growth capital formula is reduced by $14.254 million[6] as a result of the true-up of over-forecasted 2022 gross customer additions.

2022 Growth Capital True-up		
2022 Actual Gross Customer Addition	16,477	Section 2, Table 2-3
2022 Forecast Gross Customer Addition	20,000	G-366-21 2022 FEI Annual Review Decision
Difference	(3,523)	Line 12 - Line 13
2022 Unit Cost Growth Capital ($/customer)	4,046	G-366-21 2022 FEI Annual Review Decision
Growth Capital True-up in 2023	(14.254)	Line 14 x Line 15 / 1,000,000

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3.16 Please confirm that the CIAC is forecast on a formula basis and that the CIAC is not trued up in the same way that customer additions are trued up.

Response:

Not confirmed. While CIAC related to Growth Capital is forecast on a formula basis, the CIAC is also implicitly trued-up for prior year customer addition variances via the calculation provided in Table 7-2 in the Application. The true-up is embedded in the overall adjustment made to Gross Formula Growth Capex in the current year (e.g., $14.254 million shown on Line 16 in Table 7-2 of the Application).

[4] Page 27.

[5] True-up is for two years prior as the actual gross customer additions are needed for the calculation. At the time of this Application, only 2022 Actuals are available, thus the true-up for the 2022 gross customer additions forecast occurs in this Application.

[6] $4,046 x 3,523 variance of gross customer additions = $14.254 million.

3.17 Please confirm that CIAC is realized from the growth customers additions.

Response:

As shown in Table 7-1 of the Application, there are two types of CIAC:

- Formula CIAC are contributions realized from new customer additions that do not meet the minimum profitability index of 0.8 in the BCUC approved Main Extension (MX) Test.
- Forecast CIAC are recoveries for FEI's sustainment capital work, such as third-party alterations and transmission crossing replacement work.

3.18 Please provide the actual CIAC for 2022 matching the forecast of $2,388,000.

Response:

FEI notes the CIAC forecast of $2.388 million is the 2024 Forecast of formula CIAC, not the 2022 Forecast. As such, FEI interprets this IR to be requesting the 2022 Actual and Approved formula CIAC. Please refer to Table 1 below for this information.

Table 1: 2022 Approved and Actual Formula CIAC

	2022 Approved	2022 Actual
Formula CIAC ($ million)	$ 1.950	$ 5.360

3.19 Please confirm that the $285,458,000 for capital tracked outside the formula represent FEI forecasts for these items for the year 2024.

Response:

Not confirmed. The $285.458 million of capital expenditures (Section 11, Schedule 4, Line 20) is the total 2024 Forecast capital expenditures, before CIAC, which include both the formula growth capital and the forecast capital tracked outside of formula. The portion of capital tracked outside the formula is $230.819 million (Section 11, Schedule 4, Line 18), and it represents FEI's total forecast expenditures for these items in 2024.

3.20 Please provide the FEI 2022 forecast for these items and the realized expenditure for 2022.

Response:

Please refer to Table 1 below for the 2022 Approved and Actual non-formula capital expenditures.

Table 1: 2022 Approved and Actual Non-Formula Capital Expenditures

$ millions	2022 Approved	2022 Actual	Difference
Pension & OPEB (Growth Capital Portion)	1.693	1.693	-
Biomethane Assets	40.255	14.757	(25.498)
NGT Assets	8.671	4.087	(4.584)
Sustainment Capital	117.106	124.653	7.547
Other Capital	46.474	46.560	0.086
Total	**214.199**	**191.750**	**(22.449)**

7.2.3.2.1 APPROVED MAJOR PROJECTS

In 2024, FEI is forecasting capital expenditures related to the following approved projects:

- Tilbury 1A Expansion Project;
- Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project;
- Inland Gas Upgrade (IGU) Project;
- Pattullo Gas Line Replacement (PGR) Project;
- Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) Project;
- Gibsons Capacity Upgrade (GCU) Project; and
- Advanced Metering Infrastructure (AMI) Project.

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Special Projects and CPCN's		
Tilbury 1A Expansion	$	3,959
LMIPSU CPCN		6
Inland Gas Upgrade		20,721
Transmission Integrity Program (CTS TIMC)		63,107
Pattullo Gasline Replacement		153
FEI AMI CPCN		55,000
Total Capital Expenditures	$	142,946

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3.21 Please confirm that the above $142,946,000 from Major Project CPCNs expenditures is to be added to the rate base in 2024 and represents the FEI forecast of the expenditures on these projects for 2024.

Response:

Not confirmed. The $142.946 million from Section 11, Schedule 5, Line 13 of the Application is the forecast capital *expenditures* for CPCN and Special/Major projects in 2024. It is not the capital *additions* and not the amount that will be added to FEI's rate base in 2024. Capital expenditures for CPCN and Special/Major projects are not added to FEI's rate base until the work has been determined to be substantially complete with the associated assets placed in-service. The total amount of capital additions related to CPCN and Special/Major projects that are forecast to be added to FEI's rate base in 2024 is $62.185 million, which is shown on Line 19 of Table 7-7 of the Application, or Section 11, Schedule 5, Line 31 of the Application. Please refer to the response to BCOAPO IR1 11.1 for the breakdown of the capital additions in 2024 related to CPCNs and Special/Major projects.

1.5.5 Depreciation (Section 7)

Depreciation expense in 2024 is forecast to increase the 2024 deficiency by $7.803 million compared to 2023 Approved. This increase is primarily due to the additions of the CPCN and Major projects noted above. The increase in depreciation expense is partially offset by approximately $0.098 million of CIAC from net additions, resulting in a net increase of $7.705 million in depreciation expense.

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3.22 Please discuss whether or not these additions related to CPCNs and others capital are offset by any retirements of assets and if so please quantify the amount.

Response:

Please refer to the response to CEC IR1 3.21. The 2024 additions related to CPCNs and Special/Major projects are not offset by any of the 2024 forecast retirements of assets.

To clarify, an equal and offsetting amount of retirements are recorded in both the gross plant and accumulated depreciation schedules, equivalent to the gross book value of the asset, with any difference between the retirement amount and the accumulated depreciation at the time of asset retirement reflected as an asset gain or loss within the accumulated depreciation schedules. Further, depreciation is only calculated based on the opening balance of gross plant, including CPCNs added to plant January 1, 2024, and is therefore unaffected by asset retirements during the year.

1.5.6 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2024 increased by $19.048 million, primarily due to the increased amortization of the Demand-Side Management (DSM) deferral account resulting from increased DSM expenditures, and the reduced credit amortization from the Emissions Regulation deferral account resulting from reduced carbon credits available for monetization. These increases were partially offset by reduced amortization from the Pension & OPEB Variance deferral account, the credit amortization from the proposed new PST Rebate on Select Machinery and Equipment deferral account, and reduced amortization expense from the non-rate base Flow-through deferral account and the MRP Earnings Sharing deferral account.

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3.23 Please provide an explanation for the $19,048,000 increase in amortization of the deferral accounts in terms of the calculated components giving rise to this figure and reference to where in section 7 and/or section 12 this increase is provided.

Response:

Please refer to the response to BCUC IR1 1.2.

3.24 Please provide the DSM increased deferral reference and amount in the above $19,048,000 figure or the calculations deriving the above figure that would be derived from the DSM increase.

Response:

Please refer to the response to BCUC IR1 1.2.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2024 deficiency by $3.252 million through changes in financing rates, as well as changes in the ratio of long-term debt versus short-term debt.

For 2024, FEI forecasts a mid-year long-term debt issue of $200 million and forecasts a short-term debt rate of 5.56 percent, which is an increase from the 3.95 percent short-term debt rate embedded in the 2023 Approved revenue requirement. Overall, the 2024 deficiency is increased by $2.838 million due to financing rate changes and increased by $0.414 million as a result of the ratio change between long-term and short-term debt.

In calculating its 2024 revenue deficiency, FEI has utilized its currently approved capital structure and ROE of 38.5 percent and 8.75 percent, respectively, as approved by Order G-129-16. As explained in Section 8.1, FEI is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which is expected to be issued in the upcoming months. FEI will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

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3.25 Please provide the calculations giving rise to the determination of a $2.838 million increase related to financing rate changes, including short-term and long-term debt.

Response:

Please refer to Table 1 below for the calculation for the $2.838 million of revenue deficiency due to financing rate changes.

Table 1: 2024 Revenue Deficiency due to Financing Rate Changes

Line	Particular	Reference	2023 Approved	2024 Forecast	Change
1	LTD Rate	Section 11 - Schedule 26, Line 1, Column 5	4.70%	4.69%	-0.01%
2	STD Rate	Section 11 - Schedule 26, Line 2, Column 5	3.95%	5.56%	1.61%
3	ROE	Section 11 - Schedule 26, Line 3, Column 5	8.75%	8.75%	0.00%
4					
5	2024 Forecast Debt and Equity				
6	LTD Portion	Section 11 - Schedule 26, Line 1, Column 3			3,379,517
7	STD Portion	Section 11 - Schedule 26, Line 2, Column 3			197,263
8	Common Equity	Section 11 - Schedule 26, Line 3, Column 3			2,239,123
9	Total Rate Base ($000s)	Sum of Line 6 to Line 8			5,815,903
10					
11	2024 Deficiency				
12	LTD	Line 1 x Line 6			(338)
13	STD	Line 2 x Line 7			3,176
14	ROE	Line 3 x Line 8			-
15	**Total due to Financing Rate Change**	**Sum of Line 12 to Line 14**			**2,838**

3.26 Please provide the calculations giving rise to the determination of a $0.414 million increase related to a change in the ratio of long-term and short-term debt.

Response:

Please refer to Table 1 below for the calculation of the $0.414 million, which is the revenue deficiency due to the ratio change between long-term and short-term debt.

Table 1: 2024 Revenue Deficiency due to Financing Ratio Change between Long-term and Short-term Debt

Line	Particular	Reference	Amount ($000s)
1	2023 Approved Earned Return	Section 11 - Schedule 16, Line 26, Column 2	369,952
2	2024 Forecast Earned Return	Section 11 - Schedule 16, Line 26, Column 5	365,254
3	Total Change in Earned Return	Line 2 - Line 1	(4,698)
4			
5	Other Change in Earned Return		
6	Less: Financing Rate Change Only	CEC IR1 3.25, Table 1, Line 15	2,838
7	Less: Rate Base Growth	Section 11 - Schedule 1, Line 19, Column 2	(7,950)
8	**Remaining Change in Earned Return - Due to Ratio Change Only**	**Line 3 - Line 6 - Line 7**	**414**

3.27 Please provide the reason there is not an increase or decrease related to the quantity of debt to be issued given that FEI intends to issue $200 million in long term debt in 2024.

Response:

The issuance of the $200 million in long-term debt does not have an impact on the quantity of overall debt as it effectively displaces other short-term debt which changes the financing ratio between long-term and short-term debt. Furthermore, the average embedded long-term financing rate changes each time a long-term issuance is made. As such, the $200 million long-term debt issuance in 2024 will also change the average long-term debt financing rate in 2024.

FEI notes that, on September 5, 2023, the BCUC issued Decision and Order G-236-23 on Stage 1 of the GCOC proceeding. In consideration of the changes stemming from this decision, FEI may make changes to its planned long-term debt issuance in 2024. FEI will be filing an Evidentiary Update to this annual review in early October which will incorporate the impact from the GCOC decision.

3.28 Please provide FEI's expectation, in terms of the quantitative amount, for FEI using its short-term debt borrowing capability to add short-term debt.

Response:

As noted in the response to CEC IR1 3.27, FEI will be filing an Evidentiary Update to the 2024 Annual Review in early October to incorporate the recently issued Decision and Order G-236-23 on Stage 1 of the GCOC proceeding. The quantity of short-term debt for 2024 is expected to change given the GCOC decision. However, in order to be responsive, FEI provides the following response based on the information filed in this Application.

FEI anticipates an average short-term debt balance of $197.263 million in 2024 (as shown in Section 11, Schedule 26, Line 2, Column 3) against the principal amount of its committed credit facility of $700 million. FEI notes that it is planning to increase its credit facility by $200 million, as approved by Order G-211-23. FEI will continue to utilize a combination of short- and long-term debt and choose the optimal financing strategy based on market conditions at the time of the issuance.

3.29 Please confirm that when FEI has applied its set 38.5% equity thickness to its capital structure and has set its debt issue for $200 million in July 2024 that the short-term debt capability picks up the required amounts as utility expenditures take place throughout the year.

Response:

Not confirmed. While the remaining amount of the forecast rate base (i.e., the amount not financed by equity or long-term debt) will be financed by short-term debt, amounts outside of rate base will be financed using a combination of equity and debt.

Please also refer to the responses to CEC IR1 3.27 and 3.28 regarding the impacts of the recently issued GCOC decision.

FORTISBC ENERGY INC. FEI Annual Review for 2024 Rates - July 28, 2023

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Particulars	2023 Approved Earned Return	Amount	Ratio	2024 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Long Term Debt	$ 159,754	$ 3,379,517	58.11%	4.69%	2.72%	$ 158,363	$ (1,391)
Short Term Debt	9,979	197,263	3.39%	5.56%	0.19%	10,968	989
Common Equity	200,219	2,239,123	38.50%	8.75%	3.37%	195,923	(4,296)
Total	$ 369,952	$ 5,815,903	100.00%		6.28%	$ 365,254	$ (4,698)
Cross Reference		Schedule 2, Line 30, Column 3					

3.30 Please provide the similar data to the above for the 2022 & 2023 years.

Response:

Please refer to Table 1 and Table 2 below for the return on capital for 2022 Approved and 2023 Approved, respectively. The 2022 Approved (i.e., Table 1) is from the Compliance Filing to the Annual Review for 2022 Delivery Rates Decision and Order G-366-21. The 2023 Approved (i.e., Table 2) is from the Evidentiary Update to the Annual Review for 2023 Delivery Rates (as approved by Order G-352-22).

Table 1: Return on Capital from FEI Annual Review for 2022 Rates

Particulars	2021 Approved Earned Return	Amount	Ratio	2022 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Long Term Debt	$ 147,276	$ 3,218,288	59.50%	4.65%	2.77%	$ 149,765	$ 2,489
Short Term Debt	2,691	108,374	2.00%	2.31%	0.05%	2,503	(188)
Common Equity	175,594	2,082,545	38.50%	8.75%	3.37%	182,223	6,629
Total	$ 325,561	$ 5,409,207	100.00%		6.18%	$ 334,491	$ 8,930

Table 2: Return on Capital from FEI Annual Review for 2023 Rates

Particulars	2022 Approved Earned Return	Amount	Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Long Term Debt	$ 149,765	$ 3,402,586	57.25%	4.70%	2.69%	$ 159,754	$ 9,989
Short Term Debt	2,503	252,626	4.25%	3.95%	0.17%	9,979	7,476
Common Equity	182,223	2,288,222	38.50%	8.75%	3.37%	200,219	17,996
Total	$ 334,491	$ 5,943,434	100.00%		6.22%	$ 369,952	$ 35,461

3.31 Please confirm that the fact that FEI requires a reduced earned return in 2024 from that approved in 2023 reflects FEI's expected ability to meet its capital expenditure and operating requirements with lower requirements for equity and long-term debt and a $0.989 million increase in short-term debt requirements.

Response:

Not confirmed. The earned return represents the debt and equity financing costs incurred each year related to the investments made in FEI's rate base. Increases or decreases in FEI's earned return are a function of FEI's rate base and the attached debt and equity rates used to finance the rate base, and are not directly correlated with FEI's expected capital or operating requirements.

FEI's rate base includes the net plant investment (i.e., the net capital investment made in FEI's rate base) and also includes other items such as mid-year deferral balances. As discussed in Section 7 of the Application, FEI's 2024 Forecast rate base forecast includes large credit balances for its MCRA and CCRA deferral accounts. These credit balances have the impact of lowering FEI's rate base and associated earned return for the year. These deferrals will amortize in a future period, and as a result, FEI's rate base and earned return will increase accordingly.

1.5.8 Taxes (Section 9)

FEI's 2024 property taxes are forecast to increase by $4.215 million or 5.3 percent from 2023 Approved. The increase is primarily driven by higher assessed values of distribution lines and transmission lines, as well as an increase in in-lieu taxes.

There has been no change in the income tax rate of 27 percent from 2023. Taxes are forecast to increase in 2024 by $16.653 million or 32.2 percent from 2023 Approved. The largest driver of the increase in 2024 is lower income tax deductible through CCA, which led to an increase in income tax expense by $12.284 million. The lower CCA is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024). Income taxes are also higher as a result of higher amortization of deferred charges as well as depreciation, which is partially offset by lower taxable temporary differences associated with pension and higher non-taxable temporary differences associated with removal costs.

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3.32 Please describe the CCA incentive assessment phase out from start to anticipated finish if this information has been made available by government.

Response:

The phase-out of the Accelerated Investment Incentive (AII) is from 2024 to 2027. The description of the AII is provided by the Government of Canada[7] and is summarized as follows:

> The incentive's general rule is made up of two elements:
>
> - applying the prescribed CCA rate for a class to up to one-and-a-half times the net addition to the class for the year
> - suspending the CCA half-year rule (and equivalent rules for Canadian vessels and Class 13 property)
>
> As a result, EP (Eligible Property) that would be subject to the half-year rule, in essence, qualifies for an enhanced first-year allowance equal to three times the normal first-year deduction. EP not normally subject to the half-year rule (for example, a patent, franchise or limited-period licence) qualifies for one-and-a-half times the normal first-year deduction.

And for the application and phase-out:

> You must acquire the EP after November 20, 2018, and it must be available for use before 2028 in order to qualify for the AII. A phase-out period begins for property that becomes available for use after 2023.
>
> For **EP** that **would** normally **be subject to the half-year rule** (or an equivalent rule) and that becomes available for use during the 2024–2027 phase-out period, the enhanced first-year allowance is reduced to **two times** the normal first-year CCA deduction. The incentive effectively suspends the half-year rule (and equivalent rules). In essence, you can calculate CCA at the rate relevant to that class without applying the half-year rule.
>
> For **EP** that **would not** normally **be subject to the half-year rule** (or an equivalent rule), and that becomes available for use during the 2024–2027 phase-out period, the enhanced first-year allowance is generally equal to **one-and-a-quarter times** the normal first-year CCA deduction.

[7] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html.

Formula Drivers

Table 9-1: Property Tax Components ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Distribution Assets	$ 27.938	$ 29.252	$ 30.247
2	Transmission Assets	20.167	20.951	21.434
3	Gas Storage Assets	7.818	8.408	8.597
4	Manufactured Gas Assets	0.051	0.062	0.065
5	General Assets	6.652	6.092	6.289
6	In-Lieu	16.323	12.820	16.510
7	BCER Fees	0.287	0.292	0.295
8	Total Property Taxes	79.236	77.877	83.436
9	Less: Property Tax Transferred to BVA	(0.092)	(0.092)	(0.077)
10	Net Property Tax	79.144	77.785	83.359
11				
12	Forecast Change from 2023 Approved			5.3%
13	Forecast Change from 2023 Projected			7.2%

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3.33 For the Table 9-1 please provide the assessed values for 2023 and the forecast assessed values for 2024 and compute the average assessed value changes forecast for 2024.

Response:

Please refer to the following table.

Table 1: 2023 and 2024 Assessed Values ($ millions) and % Change from 2023

	2023	2024	% Change from 2023
Distribution Assets	1,666.038	1,770.277	6.3%
Transmission Assets	817.303	866.887	6.1%
Gas Storage Assets	386.645	424.150	9.7%
Manufactured Gas Assets	1.063	1.159	9.0%
General Assets	293.569	321.920	9.7%
	3,164.618	3,384.393	6.9%

3.34 Please also provide the average rate changes for each category and compute the average rate change for all assets.

Response:

Please refer to the following table for the average tax rate changes.

	Tax Rate in $ / $1,000 of Assessment			
Description	2023 Total Tax Rate	2024 Total Tax Rate	Change in Average Tax Rate	% Change in Average Tax Rate
Distribution Assets	26.05329	25.26520	(0.78808)	-3.0%
Gas Storage Assets	28.37760	27.32289	(1.05471)	-3.7%
General Assets	21.74542	20.26991	(1.47551)	-6.8%
Manufactured Gas Assets	58.15390	55.92180	(2.23210)	-3.8%
Transmission Assets	20.77649	19.56110	(1.21538)	-5.8%
Average Tax Rate	26.72714	25.54244	(1.18471)	-4.4%

3.35 Please confirm that FEI made the forecast for property tax assessments incorporated above.

Response:

FEI prepared the property tax expense forecasts provided in Table 9-1 of the Application. Please also refer to the response to BCUC IR1 14.1.

3.36 Please confirm or otherwise explain that the rate increases are those made by municipalities and others authorized to apply property tax to utility properties.

Response:

FEI confirms that tax rate increases or decreases are made by municipalities and others who are authorized to assess property tax against utility assets.

3.37 Please confirm that the FEI forecast for 2023 Approved was in excess of what FEI now projects, such that 1.9% of the 7.2% increase from Projected is caused by the prior year forecast in excess, representing about 26% of the 7.2% increase.

Response:

Please refer to the response to BCUC IR1 14.1.

The method of calculation described in this question is not correct. FEI re-forecasts property taxes annually and the variances are flowed through to customers annually. Accordingly, there is no compounding of variances. The percentage change of 7.2 percent is simply the percentage change between 2023 Projected and 2024 Forecast; it does not incorporate variances from 2023 Approved. In other words, the two percentages provided below Table 9-1 are simply two methods of comparison (i.e., comparing the percentage increase in 2024 Forecast to 2023 Approved, or comparing the percentage increase in 2024 Forecast to 2023 Projected).

3.38 Please confirm that customer rates as related to property taxes are set on the basis of the forecast and that the property taxes do not have a forecasting deferral account.

Response:

Not confirmed. While property taxes are forecast, as noted on page 82 of the Application, variances from the forecast are recorded in the Flow-through deferral account:

> Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and will be returned to or collected from customers in the following year.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2021	136.7	1,143.76								
2	Aug-2021	137.0	1,143.96								
3	Sep-2021	137.2	1,142.37								
4	Oct-2021	137.9	1,140.94								
5	Nov-2021	138.1	1,129.51								
6	Dec-2021	138.0	1,132.93								
7	Jan-2022	139.4	1,155.32								
8	Feb-2022	140.4	1,153.57								
9	Mar-2022	143.0	1,161.00								
10	Apr-2022	144.2	1,164.51								
11	May-2022	146.1	1,159.89								
12	Jun-2022	146.5	1,167.14	140.4	1,149.58						
13	Jul-2022	147.6	1,162.26								
14	Aug-2022	147.0	1,171.52								
15	Sep-2022	147.8	1,171.94								
16	Oct-2022	148.6	1,174.29								
17	Nov-2022	148.1	1,176.97								
18	Dec-2022	147.1	1,153.31								
19	Jan-2023	148.1	1,180.04								
20	Feb-2023	149.1	1,175.83								
21	Mar-2023	149.7	1,191.20								
22	Apr-2023	150.4	1,199.14								
23	May-2023	151.0	1,199.14								
24	Jun-2023	151.6	1,199.14	148.8	1,179.57	6.031%	2.609%	51%	49%	4.354%	2024

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3.39 The CEC has performed the following calculations using the above data and found the following.

CEC INFLATION CALCULATION	
BC CPI Index	BC AWE
147.6	1162.26
147.0	1171.52
147.8	1171.94
148.6	1174.29
148.1	1176.97
147.1	1153.31
148.1	1180.04
149.1	1175.83
149.7	1191.20
150.4	1191.14
151.0	1199.14
151.6	1199.14
1786.1	14146.78

CEC - CPI Change Calculation	
Average Rate	Prior Yr Average
148.8417	140.4
Difference in Average	
8.4417	
Percent Increase in Average	
6.01258%	

CEC - BC-AWE Change Calculation	
Average Rate	Prior Yr Average
$1,178.898	$1,149.580
Difference in Average	
29.3183	
Percent Increase in Average	
2.55035%	

The CEC has identified the following differences in the data calculations:

CEC BLENDED INFLATION RATE	
51% CPI & 49% AWE	
CEC RATE	FEI RATE
4.31609%	4.35400%
Calculation Difference	
0.03791%	
Error Difference	
0.87070%	

3.40 Please identify any mistake the CEC has made in its calculations and/or comment upon the difference identified.

Response:

For ease of reference, FEI has prepared the FEI and CEC I-Factor calculation methodologies side by side in the summary below.

	CPI			AWE			Weightings		Inflation Rate		
	FEI	CEC	Difference	FEI	CEC	Difference	CPI	AWE	FEI	CEC	Difference
Prior year average	140.3750	140.4000	(0.0250)	1,149.5750	1,149.5800	(0.0050)					
Jul-22	147.6000	147.6000	-	1,162.2600	1,162.2600	-					
Aug-22	147.0000	147.0000	-	1,171.5200	1,171.5200	-					
Sep-22	147.8000	147.8000	-	1,171.9400	1,171.9400	-					
Oct-22	148.6000	148.6000	-	1,174.2900	1,174.2900	-					
Nov-22	148.1000	148.1000	-	1,176.9700	1,176.9700	-					
Dec-22	147.1000	147.1000	-	1,153.3100	1,153.3100	-					
Jan-23	148.1000	148.1000	-	1,180.0400	1,180.0400	-					
Feb-23	149.1000	149.1000	-	1,175.8300	1,175.8300	-					
Mar-23	149.7000	149.7000	-	1,191.2000	1,191.2000	-					
Apr-23	150.4000	150.4000	-	1,199.1400	1,191.1400	8.0000					
May-23	151.0000	151.0000	-	1,199.1400	1,199.1400	-					
Jun-23	151.6000	151.6000	-	1,199.1400	1,199.1400	-					
Current year average	148.841700	148.841667	0.000033	1,179.565000	1,178.898333	0.666667					
Difference	8.4667	8.4417	0.0250	29.9900	29.3183	0.6717					
% Increase	6.03100%	6.01258%	0.0184%	2.60900%	2.55035%	0.0586%	51.000%	49.000%	4.35400%	4.31609%	0.03791%

The main difference between the two calculations is the CEC calculation is using an incorrect AWE data point for April 2023. The remaining differences are minor rounding inconsistencies which would result in an I-Factor calculation difference of 0.00949 percent if the April 2023 data point was corrected. A revised calculation is included below to demonstrate this immaterial difference due to rounding.

	CPI			AWE			Weightings		Inflation Rate		
	FEI	CEC	Difference	FEI	CEC	Difference	CPI	AWE	FEI	CEC	Difference
Prior year average	140.3750	140.4000	(0.0250)	1,149.5750	1,149.5800	(0.0050)					
Jul-22	147.6000	147.6000	-	1,162.2600	1,162.2600	-					
Aug-22	147.0000	147.0000	-	1,171.5200	1,171.5200	-					
Sep-22	147.8000	147.8000	-	1,171.9400	1,171.9400	-					
Oct-22	148.6000	148.6000	-	1,174.2900	1,174.2900	-					
Nov-22	148.1000	148.1000	-	1,176.9700	1,176.9700	-					
Dec-22	147.1000	147.1000	-	1,153.3100	1,153.3100	-					
Jan-23	148.1000	148.1000	-	1,180.0400	1,180.0400	-					
Feb-23	149.1000	149.1000	-	1,175.8300	1,175.8300	-					
Mar-23	149.7000	149.7000	-	1,191.2000	1,191.2000	-					
Apr-23	150.4000	150.4000	-	1,199.1400	1,199.1400	-					
May-23	151.0000	151.0000	-	1,199.1400	1,199.1400	-					
Jun-23	151.6000	151.6000	-	1,199.1400	1,199.1400	-					
Current year average	148.841700	148.841667	0.000033	1,179.565000	1,179.565000	-					
Difference	8.4667	8.4417	0.0250	29.9900	29.9850	0.0050					
% Increase	6.03100%	6.01258%	0.0184%	2.60900%	2.60834%	0.0007%	51.000%	49.000%	4.35400%	4.34451%	0.00949%

3.41 Please comment upon whether such a calculation should be made after deducting the .500% inflation factor reduction, which FEI uses to determine its expenditure forecast.

Response:

As explained in the 2020-2024 MRP Application (and provided on page 48 of the MRP Decision), the X-Factor is:

> an adjustment to the inflation factor (I-Factor) for the difference between the economy-wide inflation factors (used in the indexing formula) and the real cost inflation of the utility. [Emphasis Added]

Furthermore, in the MRP Decision (pages 61-62), the BCUC approved an X-Factor of 0.5 percent inclusive of the stretch factor. As such, the X-Factor of 0.5 percent should be applied to the I-Factor, and the I-Factor calculation should be made first with the 0.5 percent X-Factor deduction occurring afterwards.

3.42 The CEC has applied the difference in its calculations against the growth capital and against the O&M expenditures as follows:

CEC CALCULATION OF FEI DIFFERENCE IMPACTS			
Expenditure Type	Expenditure FEI Applied For	Difference	Amount of Impact
Gross O&M	$370,207,000	0.25%	$911,983
Growth Capital	$54,639,000	0.25%	$134,600
		Total	$1,046,583

Please comment on the CEC calculation of the difference and whether or not this is a correct assessment of a difference if the difference calculation at .25% were correct.

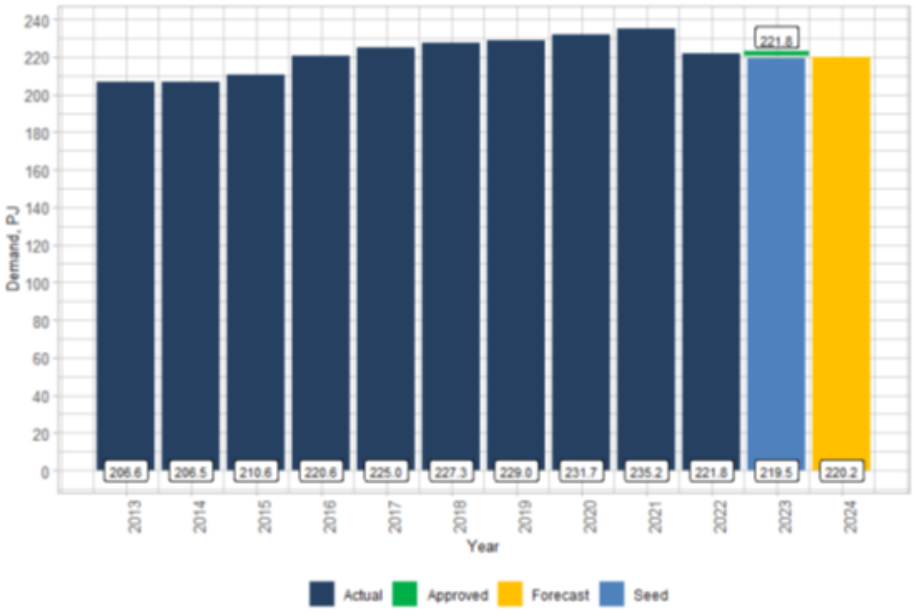
Response:

Please refer to the response to CEC IR1 3.40 where FEI identified an error in the CEC's calculation for the I-Factor. As such, the calculation provided in the question above is neither correct nor applicable.

CUSTOMER GROWTH VOLUMES AND REVENUES. (SECTION 3)

4. Reference: Exhibit B-2, Page 17-18, Page 21, Page 26, Page 29 and Page 30

Figure 3-1: Total Energy Demand in PJ



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4.1 Please provide each of the prior years of data used to create the Seed forecast of 219.5 PJ and show the calculation.

Response:

FEI declines to provide the requested information due to the level of effort required. On an aggregated level, which FEI's forecasting methods are based on, there are over 10 million lines of monthly data over a 10-year period. The calculation of the forecast is therefore not reproducible as part of this response. Please refer to Appendix A2 of the Application for the aggregated historical data. Additionally, a detailed description of the forecasting method is provided in Appendix A3 of the Application. FEI's demand forecast methods are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in the 2020-2024 MRP Application and FEI has consistently applied these methods to its demand forecasts throughout the MRP term.

4.2 Please provide a FEI weather-normalized forecast for the end of 2023 versus the approved amount of 221.8 PJ for 2023.

Response:

The FEI weather-normalized forecast for 2023 (Seed) is 219.5 PJ as shown in Figure 3-1 of the Application (and as referenced in the preamble above), which is compared against the 2023 Approved demand of 221.8 PJ. FEI notes that only the residential and commercial classes are weather normalized.

4.3 Please confirm that over the period of COVID restrictions in BC many people stayed at home and/or worked at home versus travelling to offices.

Response:

FEI understands that an increased number of people stayed home and/or worked from home during the period of the COVID-19 restrictions, and as such, this might have resulted in additional heating requirements. However, FEI has not collected data on how many of its customers worked from home versus travelling to businesses, and does not have any specific data regarding the impact of the COVID-19 pandemic on additional heating requirements.

4.4 Please provide any analysis of the percentage degree to which people were more frequently home-based versus travelling to businesses.

Response:

Please refer to the response to CEC IR1 4.3.

4.5 Please provide any analysis FEI may have of the additional home heating requirements for residential customers versus years prior to COVID.

Response:

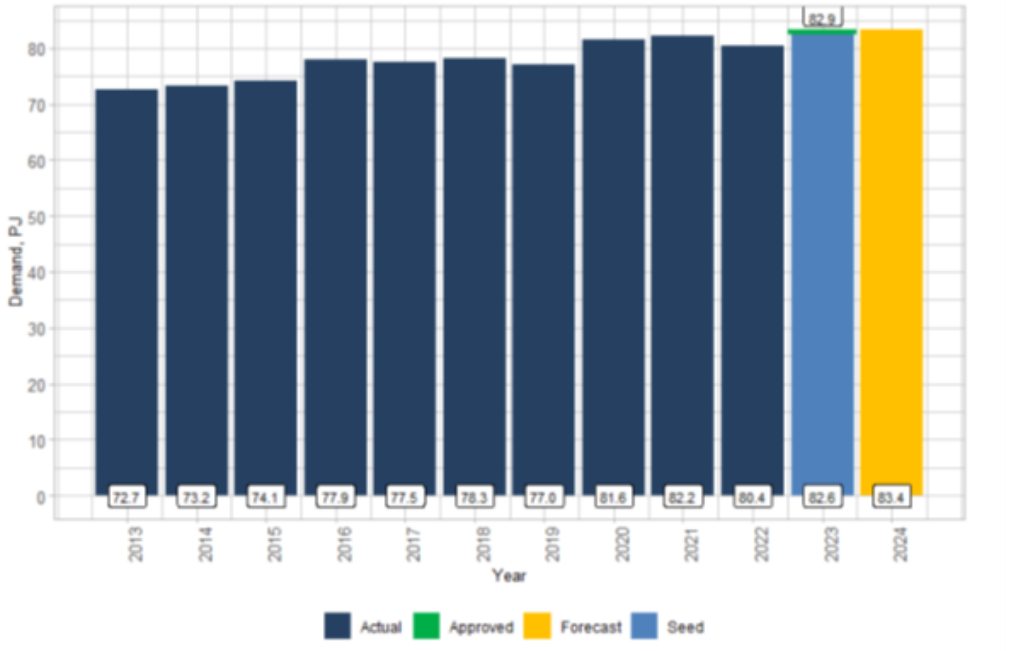
Please refer to the response to CEC IR1 4.3.

4.6 Please provide any analysis FEI may have with respect to commercial building heating requirements for commercial customers prior to COVID.

Response:

Please refer to the response to CEC IR1 4.3.

Figure 3-4: Normalized Residential Demand



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4.7 Please confirm that the Seed forecast would be lower if the COVID years of 2020 and 2021 were removed from the forecast and prior years 2016, 2017, 2018, 2019 and 2022 were used to create the Seed forecast.

Response:

Based on FEI's forecasting methods, the 2023 Seed year would be lower if 2020 and 2021 were removed from the calculation as the demand was comparatively higher in those years; however, FEI has no data to support that the primary reason for the increased demand in those years was a result of the COVID-19 pandemic. There are many factors at play in any given year that could impact, positively and negatively, the overall demand. Furthermore, there is also no indication or

quantifiable evidence that suggest the trend of working from home would not be continuing post-COVID.

FEI does not consider it appropriate to selectively pick and choose which years should form part of the annual demand forecast. Such an approach would lead to inconsistent application of forecasting methods and require an inappropriate degree of subjectivity, with little to no benefit to customers. It is understood that there will be some variability in demand forecasting and that the actual and forecast results will differ. This is why FEI is approved to capture variances in annual demand in either the RSAM or the Flow-through deferral accounts and return/recover any variances to/from customers in subsequent years. Further, as demonstrated in Appendix A2 of the Application, the performance of FEI's forecasting method is consistently achieving small variances between actuals and forecast. For example, the average percentage variance in forecast versus actual residential demand was 2.8 percent over the past five years.

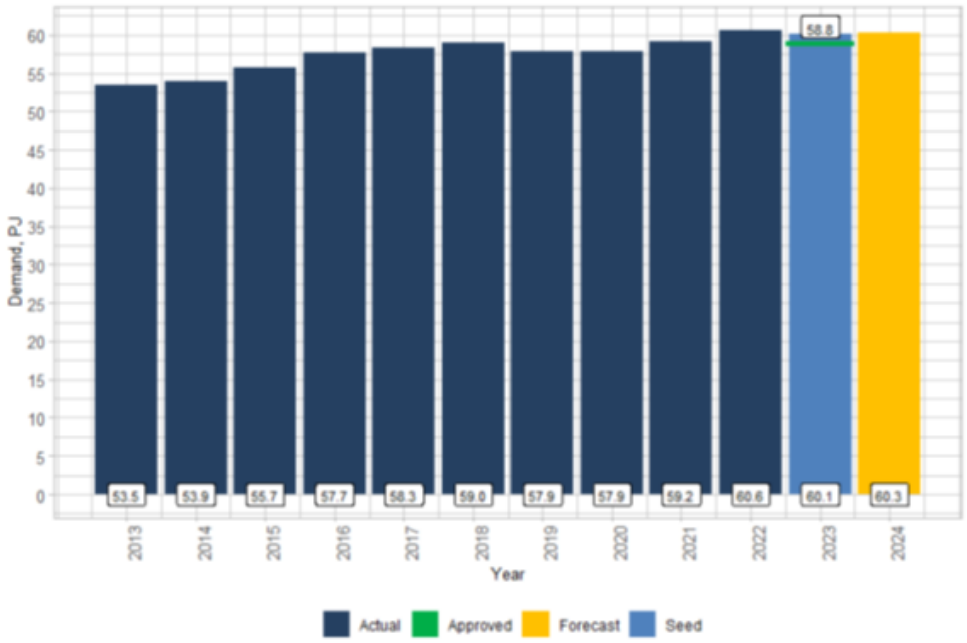
However, in order to be responsive, FEI calculated the normalized residential demand for the 2023 Seed forecast to be approximately 80 PJ with the historical data from 2020 and 2021 excluded as requested. This is approximately 2.6 PJ (or 3.1 percent) less than the 2023 Seed forecast of 82.6 PJ (which included the 2020 and 2021 data). A 2.6 PJ or (3.1 percent) variance between actual and forecast demand in any given year is normal and not unexpected. It is also in line with the average variance in the last five years. In any case, as highlighted above, the variances will be captured by deferral accounts and returned to/recovered from customers through rates in the subsequent years.

4.8 Please provide a FEI Seed forecast excluding the COVID years in a fashion FEI would use to create such a Seed forecast.

Response:

Please refer to the response to CEC IR1 4.7.

Figure 3-9: Commercial Demand[16]



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4.9 Please provide a weather-normalized graphic for the commercial demand in the same form as Figure 3-9.

Response:

As described in Appendix A3 of the Application, the commercial demand shown in Figure 3-9 is already weather normalized.

4.10 Please provide the FEI explanations for the use per customer increases from 2020 to 2021, 2022 in Rate Schedules 2, 3, and 23.

Response:

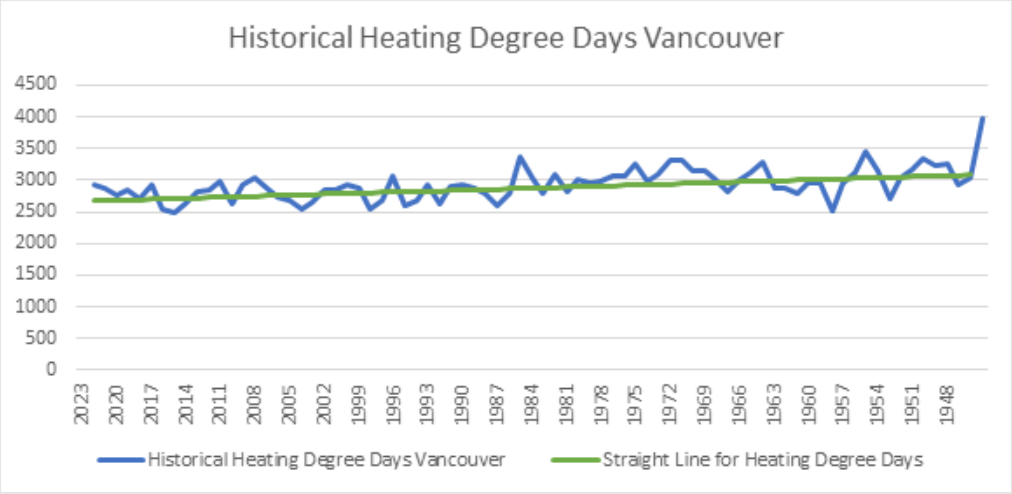
FEI cannot definitively explain the use per customer increases from 2020 to 2022 in Rate Schedules 2, 3 and 23. Any change in commercial UPC in a given year is a result of many factors that may be both compounding and offsetting.

The forecast for the small commercial and large commercial sectors is not based on specific knowledge of usage patterns or industry changes. FEI currently has an average of nearly 100,000

commercial customers representing over 180 different industry sectors. It is not possible to determine the causes of specific shifts, positively or negatively, in consumption.

These industry sectors and the customers within each have heterogeneous requirements that have various impacts on their individual operations, including their energy uses. While FEI's account managers work with larger commercial customers to understand their needs, the large number of industry sectors and individual heterogeneous requirements included in these rate schedules would require extensive market research to ascertain current and future customer requirements. This level of analysis would be cost prohibitive and FEI is not confident that there would be any additional value (or more accurate forecasts) from such an approach.

FEI expects that its load will continue to be influenced by many factors that may have affected load variances in the past, including customer behavior, economic activity, DSM investments, government policies (such as environmental policy), new technology, housing formations, etc. All of these factors, positively or negatively, would have become intrinsic in the historical data, and the current methods fully account for all these intrinsic factors.



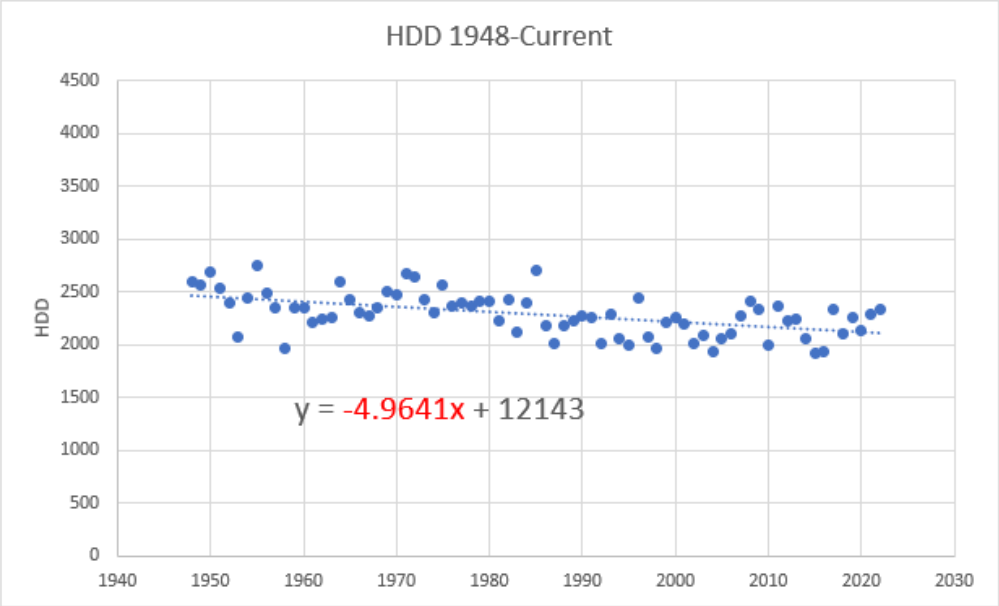
4.11 Please confirm the heating degree day information in the above graphic for Vancouver and the trendline of decreasing heating day requirements.

Response:

Confirmed; however, FEI notes that heating degree days (HDDs) are not an input to FEI's forecasting method.

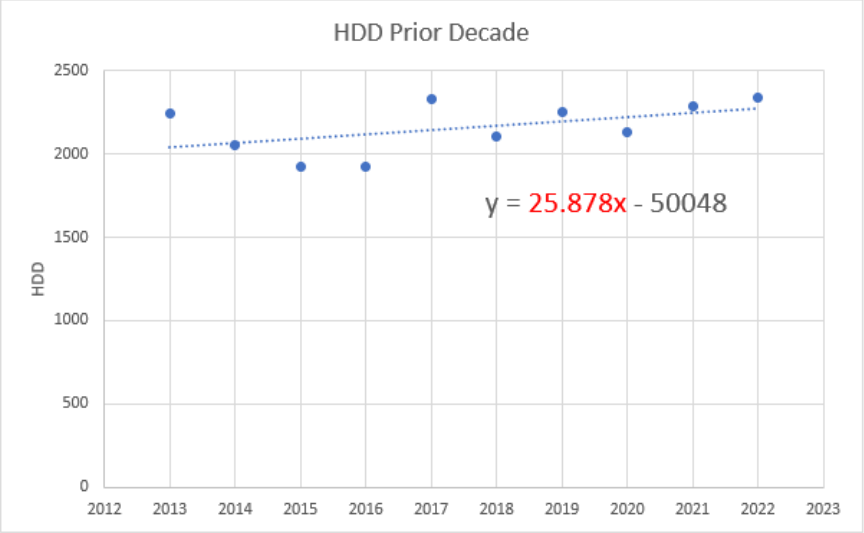
In order to investigate the characteristics of the relation, FEI has reproduced the plot below using the HDDs from the Vancouver International Airport (YVR). FEI notes that in this plot, time

increases from left to right, so the slope is opposite to the chart provided in the preamble where time decreases to the right.



FEI makes the following observations:

- When considering a trend from 1948 to present day, the annual HDD decreases by about 5 HDDs per year;
- In an average year there are approximately 2,290 HDDs, so a decline of 5 HDDs per year represents a decline of 0.2 percent per year;
- FEI does not use data back to 1948 for short-term forecasting. FEI does not consider 75-year-old data to be relevant to forecasting gas demand in 2024; and
- The HDDs trend in the last 10 years has been increasing at the rate of almost 26 HDDs (1.2 percent) per year as shown in the graph below. FEI notes that it uses 10 years of data in the ETS forecasting methods. Such an increased trend would have been reflected in the demand forecasts.



4.12 Please confirm that this graphic would be a representative proxy for the Lower Mainland and Vancouver Island, which would represent a majority of the FEI heating requirements.

Response:

Not confirmed. While this chart does depict the HDD trend since the 1940s, as explained in the response to CEC IR1 4.11, FEI does not consider 75-year-old data to be relevant to an effectively one-year forecast. Furthermore, as noted in the response to CEC IR1 4.11, the HDDs trend has been increasing at a rate of almost 26 HDDs (or 1.2 percent) per year over the last 10 years. As such, FEI does not consider the graph referenced in the preamble to this IR to be representative of current day trends for heating requirements for any of FEI's customers.

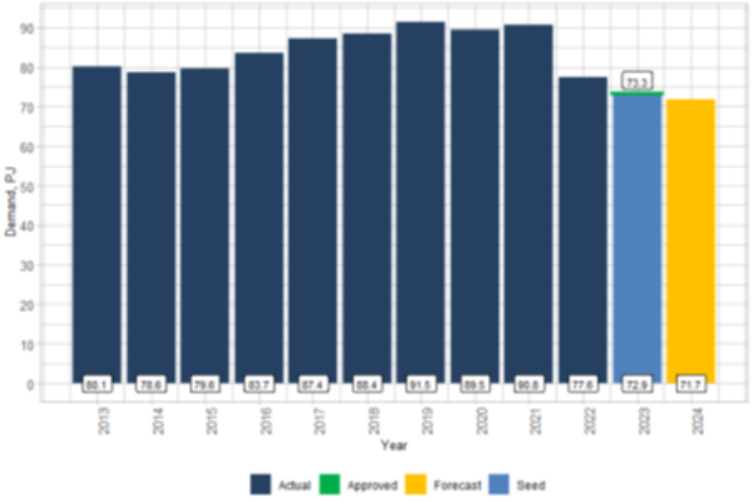
4.13 Please provide any FEI analysis of Heating Degree Days that FEI would prefer to the above heating degree day information.

Response:

FEI does not use HDDs in any part of the forecast and therefore does not have any alternative analysis. As described in Appendix A3 of the Application, FEI normalizes residential and commercial use rates for weather using a sophisticated non-linear set of equations applied to each region and rate class level. FEI uses this method because weather impacts different regions and rate classes differently.

FEI considers HDD analysis is at best, a simplistic way of accounting for weather at a high level that does not account for the different ways weather impacts different classes of customers. Using HDD analysis would mean that the same normalization factors would be applied equally between extremely weather sensitive residential customers and relatively less sensitive large commercial customers. This would lead to poor forecast performance.

Figure 3-10: Industrial Demand[17]



4.14 Please explain the significant drop in Industrial Demand for natural gas supply in 2022 and the anticipated continued loss of that demand.

Response:

FEI explained the drop in industrial demand in 2022 in Footnote 13 on pages 17-18 of the Application. FEI provides that footnote here for ease of reference:

> The primary driver of the 5.5 percent variance between 2022 Forecast and 2022 Actual demand is the impact of the expiry of FEI's contract with BC Hydro Island Generation (IG). The 2022 Forecast was prepared in the spring of 2021. At that time, it was not known that BC Hydro would not renew the IG contract and that the contract would instead expire in April 2022. As a result, the 2022 Forecast included a full year of demand from BC Hydro IG while the actual demand was only from January 2022 to April 2022 (i.e., up to the point of termination). Excluding the impact of BC Hydro IG, the aggregate variance drops to 1.3 percent, consistent with recent years' variance results.

4.15 Please explain whether or not there is a probability of further loss of the industrial demand from similar circumstances to those affecting 2022 demand.

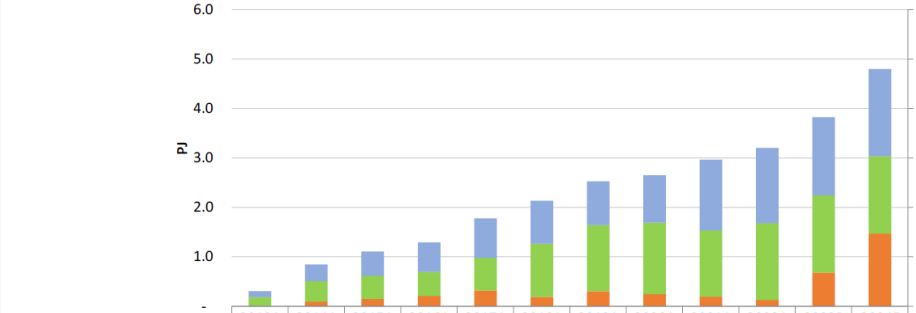
Response:

The loss of industrial load in 2022 was a one-time event from the loss of an exceptionally large customer contract and not indicative of a continuing trend. Please also refer to the response to CEC IR1 4.14.

Table 3-2: FEI Total Natural Gas Demand for NGT and non-NGT LNG (GJ per year)

GJ	2023 Approved	2023 Projected	2024 Forecast
CNG	1,468,479	1,580,569	1,762,069
LNG	1,527,696	1,561,900	1,562,600
Total NGT Demand (GJ)	**2,996,175**	**3,142,469**	**3,324,669**
Non-NGT LNG (export)	3,690,789	682,000	1,471,000
Total NGT and Non-NGT Demand (GJ)	**6,686,964**	**3,824,469**	**4,795,669**

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[18]



	2013A	2014A	2015A	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023P	2024F
RS 3/5/23/25/6P - CNG (NGT)	0.1	0.3	0.5	0.6	0.8	0.9	0.9	1.0	1.4	1.5	1.6	1.8
RS 46 - LNG (NGT)	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.4	1.3	1.6	1.6	1.6
RS 46 - LNG (Non-NGT)	-	0.1	0.1	0.2	0.3	0.2	0.3	0.2	0.2	0.1	0.7	1.5
Total CNG & LNG	0.3	0.8	1.1	1.3	1.8	2.1	2.5	2.7	3.0	3.2	3.8	4.8

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4.16 Please confirm that the ISO container LNG is able to be stored for significant periods of time with minimal loss of product and provide the quantitative storage abilities and loss potentials.

Response:

ISO containers can typically store LNG for 75 to 90 days until there is material warming and pressure increases. When the ISO container pressure becomes too high, the ISO container will either need to be unloaded or in an extreme case, vented (where there may be a loss of product). Determining storage abilities and loss potential is very complicated and depends on many other

factors such as initial temperature of the LNG, the density of the LNG, the tank gross volume, the pressure release value setpoints, and the amount of LNG in the unit as a percentage of total volume.

4.17 Please provide a summary of the Asian markets with anticipated heating requirements and the FEI sales to the specific markets.

Response:

FEI transfers the LNG to its customers at the outlet flange of the Tilbury LNG facility, pursuant to Rate Schedule 46. Because FEI's customers are responsible for the transportation and delivery of LNG past this custody transfer point, including to destinations like Asia, FEI has limited information. However, it is FEI's understanding that the majority of sales are to the interior of China, where the LNG is displacing diesel and coal in heating, electricity, and other industrial usages.

4.18 Please provide any insight FEI has with respect to domestic LNG markets and/or other world export markets that could be open to FEI export potentials.

Response:

FEI believes that the biggest near-term opportunity for LNG sales is in the marine market. FEI's LNG can power domestic and large ocean vessels, which would displace higher-emissions fuels like diesel and heavy oil. Adoption of LNG as a marine fuel for the global marine vessel market is growing as a result of the implementation of global environmental regulations that support a shift away from higher carbon fuels that have traditionally been consumed by the global marine market.

FEI has received many inquiries from customers seeking to export LNG, but believes that the Asian markets, and particularly China, continue to represent the biggest opportunity due to the demand, the higher carbon alternatives LNG is displacing, China's climate policy, and the proximity of Asia to the Tilbury facility.

4.19 Please explain when the LNG is produced for the Asian Markets, when it is shipped, and when it is needed in the Asian Winter.

Response:

FEI includes the forecast of ISO sales in its production planning at the Tilbury facility. The LNG that is sold to customers exporting it to Asian markets is comingled with all the other LNG produced at the plant. When it is loaded onto an ISO container, it is taken from the Tilbury 1A storage tank.

The winter demand and LNG price in Asia is typically highest between October and March. Given the approximate 30-day delivery period for an ISO container, the peak demand for LNG sales at Tilbury is expected to be September to February, to match the peak demand period in Asia. While some customers are mainly looking to take advantage of high demand periods in Asia, FEI is also in discussions with customers who are looking for a steady annual delivery to meet industrial production or other base load requirements.

4.20 Please confirm whether or not this FEI export LNG is displacing higher carbon content heating sources in the Asian markets.

Response:

While FEI cannot confirm the exact fuel types being displaced in each case, as FEI's customers are responsible for LNG transportation and delivery to Asia on their own, it is FEI's understanding that the LNG is displacing higher carbon fuels such as diesel and coal.

4.21 Please explain whether FEI existing customers are curtailed when the LNG is exported or produced for export.

Response:

FEI's Tilbury 1A facilities were built specifically to serve LNG markets. As such, FEI's existing customers (i.e., those customers served by FEI's distribution system) are not curtailed due to LNG being produced for sale.

4.22 Please explain whether or not LNG service is realistic for any remote communities in BC or elsewhere in North America or around the world or if the LNG market is

more realistic for densely-populated communities around the world with more expensive and less climate-friendly fuels.

Response:

FEI believes that LNG can play an important role in displacing diesel fuel presently used for power generation in certain remote communities. However, there are significant barriers, including the delivered cost of LNG to these remote communities due to long transportation distances and low economies of scale as these remote communities often do not use large volumes of energy. While densely-populated communities offer improved economies of scale, delivery costs continue to represent one of the key barriers for capturing this market.

FEI continues to monitor this market as the industry is constantly evolving with new technology, which can help address these issues. FEI will continue to engage with stakeholders in support of displacing diesel fuel to help achieve energy and emissions reduction goals in remote BC communities.

Table 3-3: Forecast Sales Revenue at 2023 Approved Rates (Commodity, Midstream, and Delivery)

Revenue ($ millions)	Approved 2023	Projected 2023	Forecast 2024
Residential[1]	1,257.965	1,111.137	1,040.799
Commercial[2]	697.400	615.794	562.438
Industrial[3]	293.752	233.884	226.655
Total	**2,249.117**	**1,960.815**	**1,829.892**

Table 3-4: Forecast Gross Margin at 2023 Approved Delivery Rates

Margin ($ millions)	Approved 2023	Projected 2023	Forecast 2024
Residential[1]	643.916	642.883	649.096
Commercial[2]	294.040	299.372	300.281
Industrial[3]	140.388	129.823	136.366
Total	**1,078.344**	**1,072.078**	**1,085.743**

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4.23 Please breakout the LNG market revenues and gross margins contained in the above amounts.

Response:

Please refer to Table 1 below for the RS 46 LNG sales revenue and gross margins.

1 **Table 1: Forecast Sales Revenue and Gross Margin at 2023 Approved Rates for RS 46 LNG**

RS 46 LNG ($ millions)	Approved 2023	Projected 2023	Forecast 2024
Revenue	64.059	27.608	35.116
Gross Margin	28.474	17.065	22.729

2
3

YEAR-END AND AVERAGE CUSTOMERS, AND OTHER COST DRIVER INFORMATION INCLUDING INFLATION (SECTION 3)

5. Reference: Exhibit B-2, Page 19, Appendix A1, Page 3, Appendix A2, Table A2-1, Page 2, Page 22, Page 41, Page 44, Page 46, Page 47, Page 51, Page 53, Page 54

Figure 3-2: Residential Net Customer Additions

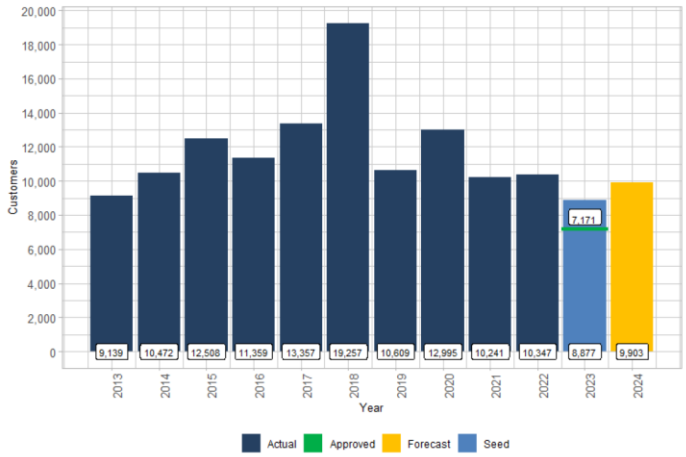

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Table A1-3: Provincial Outlook Long-Term Economic Forecast 2023

BRITISH COLUMBIA	2021	2022	2023	2024
Housing Starts, Singles, British Columbia (Thousands ('000s))	11,025	9,109	7,733	8,483
Forecast Percent Change		**-17.4%**	**-15.1%**	**9.7%**
Housing Starts, Multiples, British Columbia (Thousands ('000s))	36,582	34,752	30,534	34,972
Forecast Percent Change		**-5.0%**	**-12.1%**	**14.5%**
Total	47,607	43,861	38,267	43,455

The Conference Board of Canada. The Growth to Slow as Province Climbs the Population Pyramid: British Columbia's Outlook to 2045. Ottawa: The Conference Board of Canada, 2023

Single and Multi-Family Dwelling Housing Starts respectively can be obtained Via e-data completed in 2022-16-12 and released 2022-22-12 through CBOC subscription

Appendix A1, Page 3

FEI Customer Additions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-S*	2024-F*
RS 1	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995	10,241	10,347	8,877	9,903
RS 2	1,329	1,173	1,450	998	899	1,271	442	677	320	293	425	425
RS 3	-86	35	132	-112	252	587	945	-168	208	211	-2	-2
RS 23	9	-7	202	79	-91	-64	-777	-125	-49	-77	2	2
Industrial	27	-4	-1	-21	21	13	31	3	3	24	-5	0
NGT	5	8	13	11	14	-15	12	16	5	24	8	0
Total	10,423	11,676	14,305	12,314	14,452	21,049	11,262	13,398	10,728	10,822	9,306	10,328

Appendix A2, Table A2-1, Page 2

5.1 Please explain whether or not the A1-3 Provincial Outlook informed the 2023 Seed year forecast or whether the forecast in A2-1 is derived from some other source information.

Response:

The Provincial Outlook of housing starts by CBOC is used as an input for the residential customer forecasts.

5.2 Please explain whether or not the recent significant increase in interest rates accompanied the supporting information used to create the forecasts for customer additions for Rate Schedule 1 & 2.

Response:

Please refer to the response to BCOAPO IR1 3.1.

5.3 Please explain why Rate Schedule 2 customer additions is expected to increase so significantly and stay at that level.

Response:

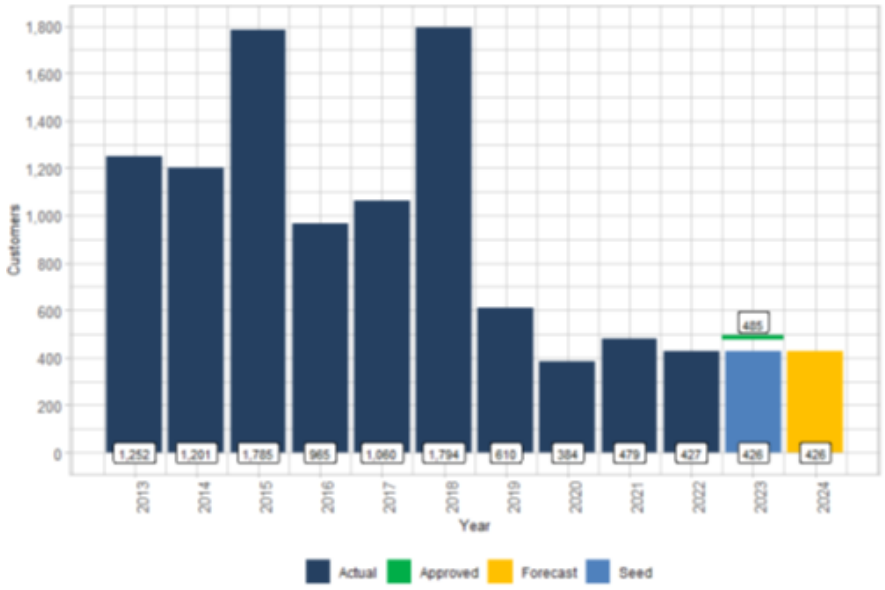
As described in Appendix A3 of the Application, the forecast method for commercial additions considers the most recent three years of customer additions by region and rate class and then holds the resulting forecast fixed for both the seed (2023) and forecast (2024) years. The large increase in Rate Schedule 2 is a result of averaging the large increase in 2020 with smaller increases in 2021 and 2022.

5.4 Please provide a Provincial Outlook Long-term Forecast for Housing Starts for 2024.

Response:

Please see Table A1-3 from Appendix A1 to the Application, as referenced in the preamble. This is the most recent forecast available from the CBOC.

Figure 3-5: Commercial Net Customers Additions (Rate Schedule 2, 3, and 23)



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5.5 Please explain the low level of commercial net customer additions starting in 2019 and continuing through to 2024.

Response:

As discussed in the response to CEC IR1 4.10, FEI cannot definitively explain the trend of commercial customers, including commercial customer additions, as FEI currently has an average of nearly 100,000 commercial customers in RS 2, 3, and 23 representing over 180 different industry sectors. Anecdotally, in addition to the impacts from the COVID-19 pandemic in 2020 through 2022, greenhouse gas intensity metrics and policies directed at new residential and commercial construction projects are likely affecting commercial attachments. Projects that deferred their commencement to 2022 because of the COVID-19 pandemic were also subjected to new policies that made it more challenging to connect to gas service.

5.6 Please provide the total additions and losses of customers that form the net additions for each of the years 2019 through 2024.

Response:

Based on the preamble, FEI assumes this question is related to commercial customers. The following table provides the breakdown of commercial net additions for 2019 to 2022. FEI does not have actual data for 2023 or 2024 at this time.

FEI Commercial Customer Additions	2019	2020	2021	2022
New Additions/Move-ins	11,866	11,162	10,660	10,223
Move-outs/Disconnection (Vacant)	(11,256)	(10,776)	(10,181)	(9,796)
Net Additions	**610**	**386**	**479**	**427**

Net additions are made up of move ins/move outs (and the timing of those activities), disconnections (voluntary and involuntary) and gross additions. Customers join and/or leave the system for many reasons. FEI does not collect or record the reason why a particular customer decides to no longer take gas service in any particular year. As a result, FEI cannot speculate on losses or additions in any given year due to a single driver such as the COVID-19 pandemic.

5.7 Please isolate the loss of customer as a result of COVID during 2020 and 2021 and discuss the rate of return to FEI as customers.

Response:

Please refer to the response to CEC IR1 5.6.

EXPENSES, DETERMINED BY THE INDEXING FORMULA PLUS ITEMS FORECAST ANNUALLY (SECTION 6)

6. Reference: Exhibit B-2, Page 41, Page 44, Page 46

Table 6-1: 2024 O&M Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula O&M	$ 299.302	$ 299.302	$ 312.561	Section 11, Schedule 20, Line 12
2	Forecast O&M	55.345	57.931	57.646	Section 11, Schedule 20, Line 23
3	Total Gross O&M	354.647	357.233	370.207	Line 1 + Line 2
4	Capitalized Overhead (16%)	(56.744)	(56.744)	(59.233)	Section 11, Schedule 20, Line 27
5	Biomethane O&M transferred to BVA	(5.237)	(5.075)	(5.817)	Section 11, Schedule 20, Line 26
6	Net O&M	$ 292.666	$ 295.414	$ 305.157	Line 3 through 5

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Table 6-2: Calculation of 2024 Formula O&M ($ millions)

Line No.	Description	Forecast 2024	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	$ 280	G-352-22 2023 FEI Annual Review Decision
2	I-Factor	3.854%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	$ 291	
4	Average Customer Forecast	1,074,994	Section 2, Table 2-2
5	2024 Inflation-Indexed O&M before 2022 True-up	$ 312.823	Line 3 x Line 4
6	2022 True-up O&M	$ (0.262)	Line 16
7	Inflation-Indexed O&M	$ 312.561	Line 5 + Line 6
8			
9	2022 O&M True-up		
10	2022 Actual 12 month Average Customers	1,067,191	FEI 2022 Annual Report
11	2022 Forecast 12 month Average Customers	1,068,490	G-366-21 2022 FEI Annual Review Decision
12	Difference	(1,299)	Line 10 - Line 11
13	Growth Factor	75%	G-165-20 MRP Decision
14	Change in Customers - True-up	(974)	Line 12 x Line 13
15	2022 Unit Cost ($/customer)	$ 269	G-366-21 2022 FEI Annual Review Decision
16	O&M True-up for 2024	$ (0.262)	Line 14 x Line 15 / 1,000,000

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6.1 Please confirm that if the Average Customer Forecast, which is a count of customers is overly optimistic (because of an overly optimistic housing starts or new net customer additions) such that the Inflation Indexed O&M would also be overly optimistic.

Response:

Not confirmed. There is no indication that FEI's customer forecast is overly optimistic. Table 1 below shows the variances in average customers between forecast and actual over the last five years. They show that the variances are small at less than 1 percent each year.

Further, even when considering the impact of the largest customer count variance in the past five years (i.e., 9,126 customers in 2018) on formula O&M, the impact would only be $2.66 million[8],

[8] 2024 Unit Cost O&M of $291 per customer x 9,126 / 1,000,000 = $2.66 million.

which represents an approximate difference of 0.85 percent from the 2024 inflation- indexed O&M of $312.561 million.

Finally, as demonstrated in Table 6-2 of the Application and referenced in the preamble, there is a true-up mechanism for the average customer forecast in the calculation of the inflation-indexed O&M.

Table 1: Variance of Average Customer Count between Actual and Forecast from 2018 to 2022

Average Customer Count	2018	2019	2020	2021	2022
Forecast	1,007,227	1,024,962	1,043,259	1,053,292	1,068,490
Actual	1,016,353	1,031,862	1,044,623	1,057,086	1,067,190
Variance	9,126	6,900	1,364	3,794	(1,300)
% Variance	0.9%	0.7%	0.1%	0.4%	-0.1%

6.2 Please explain why the true up calculation reduces the average number of customers for 2022 by 25% or takes 75% for true up purposes, while the inflation cost indexing takes the average customer forecast without a 25% reduction or 75% of the growth.

Response:

The CEC's description is incorrect in this question. The average customer forecast of 1,074,994 on Line 4 of Table 6-2 of the Application (referenced in the preamble) used to calculate the inflation-indexed O&M (i.e., Line 7 of Table 6-2) has already included the 75 percent customer growth factor multiplier. This is evident on Line 29 of Table 2-2 of the Application (and this reference to Table 2-2 is provided on Line 4 of Table 6-2). As such, the application of the 75 percent growth factor multiplier is consistent between the inflation-index O&M calculation and the true-up calculation.

> For gas control, FEI spent $0.607 million less than the formula amount in 2022. As explained in the Annual Review for 2023 Delivery Rates,[31] FEI hired one gas controller in 2021 and had intended to hire one net new gas controller per year going forward. However, FEI was unable to hire another net new gas controller in 2022 due to a combination of recruitment challenges, staff turnover, and coordinating the timing of new hires with retirements of existing employees. Hiring gas controllers is challenging as it is difficult to locate candidates with appropriate experience and skills within BC, particularly due to the high-cost housing market in the Lower Mainland and, to varying extents, in FEI's other operating territories. FEI continues to strive to increase its gas control staffing to ensure the utility will be able to meet the requirements of its customers, align with industry standards, and continue to operate in a safe and reliable manner within a progressively complex and demanding operational environment.

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6.3 Please discuss whether FEI has considered moving its gas controller operations and or other related functions to areas in the province with lower housing costs and cost of living contexts.

Response:

FEI has not considered and is not currently considering moving its Gas Control operations or related functions to other areas in the Province.

While there are some advantages to having FEI's Gas Control functions in the Lower Mainland, it would be theoretically possible to relocate to another area within the Province. However, any relocation of these functions would require careful analysis on the space requirements from a facilities perspective, the impact to existing employees and support staff, and the costs and technical challenges associated with relocation of communications and SCADA infrastructure to another location.

Additionally, other communities where FEI has a substantial presence, such as the Okanagan, also have cost-of-living challenges and factors such as space requirements for facilities and infrastructure also create challenges.

6.4 Please explain whether or not FEI's gas controller functions need to be located in its lower mainland offices or whether they can adequately be addressed in lower cost communities where FEI has substantial presence.

Response:

Please refer to the response to CEC IR1 6.3.

Table 6-4: 2024 Forecast O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Pension/OPEB (O&M Portion)	$ 9.577	$ 9.577	$ 2.555
2	Insurance	12.242	12.406	13.328
3	Integrity O&M	8.000	9.000	11.200
4	BCUC Levies	8.493	8.493	9.955
5	**Clean Growth Initiatives:**			
6	Biomethane O&M	5.237	5.075	5.817
7	Renewable Gas Development	2.000	3.069	4.052
8	NGT O&M	1.937	2.412	2.604
9	Variable LNG Production Costs	7.859	7.899	8.135
10	Forecast O&M	$ 55.345	$ 57.931	$ 57.646

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6.5 Please provide the last 5 years of insurance forecasts vs the actual insurance billings for those same years.

Response:

The 2018 through 2022 Approved and Actual insurance amounts are provided in Table 1 below.

Table 1: Approved and Actual Insurance Amounts 2018 to 2022 ($ millions)

Year	Approved	Actual
2022	$11.474	$11.485
2021	$9.908	$10.308
2020	$8.521	$8.457
2019	$5.473	$6.294
2018	$5.360	$5.203

6.6 Please explain why renewable gas development has doubled in the forecast versus 2023 approved.

Response:

FEI has described the activities and drivers of the forecast increase in renewable gas development in Section 6.3.6 (pages 52 - 54) of the Application. As explained in Section 6.3.6, FEI requires increased resources to support the development of renewable energy options such as hydrogen in response to various climate policies being introduced at the provincial and federal levels of government which seek to lower greenhouse gas emissions. Please also refer to the response to BCOAPO IR1 6.1.

Table 6-6: Insurance Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Insurance Premiums	$ 12.242	$ 12.406	$ 13.328

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6.7 Please provide the insurance premium forecasts for the five years 2018, 2019, 2020, 2021, 2022 and the actual insurance premiums for those years.

Response:

Please refer to the response to CEC IR1 6.5. FEI notes the forecast of insurance is the premiums.

6.8 Please provide FEI's claims on insurance for these last five years.

Response:

There are three claims on insurance for the last five years and two claims remain open. Please also refer to the responses to the BCUC IR1 5 series for an explanation of the Tilbury 1A project insurance proceeds.

Date of Loss	Type of Loss	Status of claim	Quantum
October 9, 2018	Property – Contingent Business Interruption	Closed	$0
November 15, 2021	Property – Flood	Open	TBD
December 20, 2022	Liability	Open	TBD

6.9 Please explain whether or not FEI self-insures any amounts and/or items.

Response:

FEI is insured for losses through Fortis Inc.'s insurance program. When losses are below the deductible, FEI self-insures those losses.

6.10 Please provide the deductible amounts for insurance which FEI must cover before insurance is applicable and available.

Response:

FEI declines to provide the details of its insurance claims in this proceeding for the following reasons:

- FEI's insurance policies are complex with numerous deductible and policy details that are not appropriate to examine within the scope of the Annual Review; and
- The information is commercially sensitive and would provide no material value in understanding this Application as FEI has already disclosed the details of its successful insurance claims that are impacting 2024 rates.

6.11 Please provide any information FEI has with respect to seeking self-insurance approval from the Commission in order to lower the costs of insurance.

Response:

FEI has no information with respect to seeking self-insurance approval from the BCUC in order to lower the costs of insurance. FEI is insured under Fortis Inc.'s insurance program, which covers the majority of Fortis Inc.'s Canadian, US and Caribbean operations, and thus leverages economies of scale and its strong corporate reputation amongst insurers to obtain competitive insurance rates and coverage terms. FEI continues to believe this is a prudent approach and has no plans to request any approvals from the BCUC related to a self-insurance approach.

Table 6-7: Integrity Digs – Activities and Expenditures

Line No.	Reason for Digs	Number of Digs per Year					
		2020 Actuals	2021 Actuals	2022 Actuals	2023 Approved	2023 Projected	2024 Forecast
1	**ILI Digs – New Tool(s):** ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment.	27	13	32	50	36	85
2	**ILI Digs – New Practice(s):** ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices.	47	25	15	30	40	30
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices	45	87	68	40	61	35
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys.	27	17	12	20	27	10
5	**Facilities Digs:** Digs identified on piping within facilities (e.g., control stations, regulator stations, compressor stations) through assessment of available design, construction, operations, and maintenance information.	0	0	1	5	2	2
6	**Total Integrity Digs**	**146**	**142**	**129**	**145**	**166**	**162**
7	Total Integrity Dig Expenditures ($ millions)	5.9	7.2	6.2	7.0	8.0	10.2
8	Cost per dig ($000s)	40	51	48	48	48	63

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6.12 Please explain why the number of digs per year increases from the 140s to the 160s, from the point of view that if additional digs are necessary could that be determined based on experience of the first 85% of digs such that the additional digs might be avoided or delayed.

Response:

No, it would not be appropriate to avoid or delay digs. The number and timing of digs projected/forecast for 2023 and 2024 are needed for FEI to maintain compliance with standards, prevent failures, and maintain alignment with industry standard practice. FEI provides further explanation of the increased 2023 Projected and 2024 Forecast digs below.

FEI provides the updated Table 6-7 below (up to the date of this response) to reflect more updated projections for the number of digs in 2023 (i.e., updated numbers are highlighted in RED).

Line No.	Reason for Digs	Number of Digs per Year					
		2020 Actuals	2021 Actuals	2022 Actuals	2023 Approved	2023 Projected	2024 Forecast
1	**ILI Digs – New Tool(s):** ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment.	27	13	32	50	36	85
2	**ILI Digs – New Practice(s):** ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices.	47	25	15	30	**42**	30
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices	45	87	68	40	**63**	35
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys.	27	17	12	20	27	10
5	**Facilities Digs:** Digs identified on piping within facilities (e.g., control stations, regulator stations, compressor stations) through assessment of available design, construction, operations, and maintenance information.	0	0	1	5	2	2
6	**Total Integrity Digs**	**146**	**142**	**129**	**145**	**170**	**162**
7	Total Integrity Dig Expenditures ($ millions)	5.9	7.2	6.2	7.0	**8.2**	10.2
8	Cost per dig ($000s)	40	51	48	48	48	63

The number of digs in 2023 Projected has increased compared to 2023 Approved primarily due to the following reasons:

- **ILI Digs – New Practice(s):** Additional digs are projected in 2023 on the basis of ILI and other data (e.g., integrity digs) that was not available and analyzed at the time of the initial estimate.
- **ILI Digs – Established Tools and Practices:** Additional digs are projected in 2023 based on analysis of information that was not known at the time of the initial estimates, including from ILI data and integrity digs.
- **Non-ILI Digs:** Additional digs are projected in 2023 in response to a December 2022 leak on the Trail Lateral 168, which occurred after the Annual Review for 2023 Delivery Rates proceeding had concluded.

The 2024 Forecast number of digs are higher than past years primarily due to the "New Tool(s)" digs. The increased number of "New Tool(s)" digs is due to the IGU and CTS TIMC Projects which are equipping pipelines to run new ILI tools. The first time a new ILI tool is run through a pipeline, it results in the forecast need for more integrity digs, as the first run can detect many features that need to be investigated through a dig.

FEI could not avoid or delay its forecast digs based on experience of the first 85% of digs, as suggested by the IR. As noted above, FEI's forecast digs are necessary to maintain compliance with standards, prevent failures, and maintain alignment with industry standard practice. FEI does, however, incorporate the findings of previously-completed integrity digs into its forecast of integrity digs. For example, integrity digs may indicate bias in the particular in-line inspection tool-reported data. If integrity digs demonstrate a non-conservative bias (i.e., ILI-reported features are found to be more serious based on the integrity dig inspection), FEI would expect to increase future digs from what would otherwise have been planned. Similarly, if integrity digs demonstrate that a given ILI tool run had a conservative bias (i.e., ILI-reported features are found to be less serious based on the integrity dig inspection), FEI may be able to reduce future digs that would otherwise have been planned.

6.13 Please describe the likely information to cause an interest in doing a dig, and please discuss whether or not there would be a gradation to this information from most concern to least concern such that lesser concern digs might not be necessary until later confirmation of the evidence of a problem getting worse over time and increased concern at a later time.

Response:

FEI could grade integrity digs from "most concern to least concern" based on several factors such as severity of failure mode (i.e., leak vs. rupture), proximity to population, and the time-dependent nature of the potential defect. However, each of the integrity digs that FEI performs are material to FEI's maintenance of its compliance to standards and prevention of failures, as well as enabling FEI to maintain alignment with industry standard practice.

There are a number of reasons why FEI may need to conduct an integrity dig:

- When FEI has specific knowledge of ILI tool-reported features that may require repair, FEI needs to assess the ILI tool-reported data relative to CSA Z662-23 Clause 10.10 defect assessment criteria.
- When FEI's analysis of an ILI tool-reported feature demonstrates the potential for future failure, FEI needs to assess the potential for future rupture or leak.
- When FEI requires dig data to assess ILI tool performance, including the potential for tool reporting bias (i.e., tool uncertainty), FEI needs to have ILI tool validation digs.

- When FEI's assessment of above-ground survey data identifies potential corrosion, it is a regulatory obligation, standard requirement, and industry standard practice to undertake an assessment of non-in-line inspected transmission pipelines.
- For Facilities Digs, it is a regulatory obligation, standard requirement, and industry standard practice to undertake assessment of facilities pipelines.
- The need for an integrity dig may also arise from any other available and relevant technical information, including observations of potential hazards (e.g., unauthorized external loading above a pipeline, visual observation of ground movement).

Table 6-8: Biomethane O&M by Project ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Program Overhead	2.648	3.880	3.986
2	City of Surrey	0.010	0.016	0.017
3	Kelowna	0.512	0.703	0.745
4	Salmon Arm	0.200	0.268	0.283
5	Fraser Valley Biogas	0.012	0.013	0.013
6	Seabreeze Farms	0.012	0.013	0.013
7	Lulu Island WWTP	0.012	0.013	0.013
8	Dickland Farms	0.012	0.013	0.013
9	City of Vancouver	0.340	-	0.572
10	REN Energy	-	0.013	0.013
11	Capital Regional District	0.004	0.013	0.013
12	Net Zero Waste	0.009	-	-
13	Delta RNG (MAS Energy)	1.467	0.133	0.133
14	Total Biomethane O&M	5.237	5.075	5.817

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6.14 Please explain which of the above are established operations and which are new or in the process of being developed.

Response:

The City of Surrey, Kelowna, Salmon Arm, Fraser Valley Biogas, Seabreeze Farms, Lulu Island WWTP and Dickland Farms are all operational. The City of Vancouver, Capital Regional District and Delta RNG are in the construction phase. REN Energy and Net Zero Waste are in the design phase.

6.15 Please explain whether or not overhead for an established operation is required at the same level as for projects being started or being developed.

Response:

Program Overhead costs for an established operation is not required at the same level as projects being started or developed. Program Overhead costs are primarily made up of costs associated with developing new agreements or projects, technical support, and customer education. While some Program Overhead costs are still required for ongoing management of established operations, a majority of the costs are accounted for on a project-by-project basis.

6.16 Please allocate the overhead to the projects based on the need/level for FEI attention to the project.

Response:

Based on the size of the team at FEI and typical day-to-day activities, FEI estimates that approximately $0.5 million can be allocated equally across the list of projects in Table 6-8, with the remainder of the Program Overhead being related to managing the Biomethane portfolio, customer education and developing new projects.

6.17 Please confirm that operating biomethane projects have their own staffing to deliver biogas upgraded to natural gas for the FEI pipeline injection.

Response:

The costs associated with operating biomethane projects include staff and materials costs but there is not necessarily staff dedicated solely to the operation of a single project. The variation in expected operating costs is based upon the fact that for most of the listed projects, FEI only operates an interconnection station which has significantly lower costs.

6.18 Please confirm whether or not each operating project at FEI requires staffing or if FEI is able to rely on the project to deliver to specifications.

Response:

None of the operating projects require full-time staffing to deliver biomethane.

For the Kelowna and Salmon Arm projects, FEI receives raw biogas which it upgrades to the pipeline specifications. In these cases, FEI owns upgrading equipment, which attracts greater costs including staff time, utility costs (electricity) and maintenance costs, which are all categorized as O&M.

In the case of Delta RNG, FEI is anticipating additional costs related to using a virtual pipeline to move biomethane which includes a labour component for trucking.

For the remainder of the operating projects, there are costs associated with maintenance (time), consumable materials and, on occasion, parts. These are all categorized as O&M costs.

Hydrogen Production Supply Opportunities – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Production Project Preliminary Feasibility:

- 2023 – continue feasibility evaluation of various hydrogen production facility development opportunities in FEI's Interior and Lower Mainland service areas. Review potential policy, regulatory and permitting requirements to offtake hydrogen from the production facilities, including distribution in the natural gas distribution system, or supply hydrogen directly to industrial customers other than through the natural gas distribution system to replace natural gas.
- 2024 – continue progress from 2023 with goal to reach Final Investment Decision on a commercial pilot.

Hydrogen Offtake Supply Opportunities – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Procurement Feasibility:

- 2023 – continue evaluation of several potential third-party proposals that are considering developing projects to produce clean hydrogen for supply to offtakes such as FEI. Review regulatory and permitting requirements to offtake hydrogen from third-party production facilities for distribution in the natural gas distribution system, or supply hydrogen directly to industrial customers other than through the natural gas distribution system to replace natural gas.
- 2024 – continue from 2023 with goal to advance one opportunity to definitive agreement.

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6.19 Please advise how long FEI anticipates it will need to reach a Final Investment Decision on a commercial pilot project.

Response:

FEI is currently progressing several early-stage hydrogen production development opportunities and anticipates reaching a final investment decision on one of these opportunities in the 2024 to

2025 timeframe subject to overcoming challenges such as technology de-risking through front-end engineering design, advancing key regulatory approval processes, and securing government funding. Please also refer to the response to BCSEA IR1 7.22.

6.20 Please provide an approximation of the potential cost for a pilot project.

Response:

FEI does not have an approximate cost for a pilot project at this time. Please also refer to the response to CEC IR1 6.19.

6.21 Please provide an approximate target for the timing of having a definitive agreement with a third-party.

Response:

FEI is currently progressing several early-stage hydrogen offtake opportunities and anticipates finalizing terms and potential definitive supply agreement(s) in the 2024 to 2025 timeframe. Please also refer to the response to BCSEA IR1 7.22.

6.22 Please describe and quantify the costs for the FEI hydrogen production and offtake projects.

Response:

The estimated dollar value amount of the 2023 Projected and 2024 Forecast total costs attributable to hydrogen production and offtake projects is detailed below:

Activity	2023 ($ million)	2024 ($ million)
Hydrogen Production Supply Opportunities –2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Production Project Preliminary Feasibility: • 2023 – continue feasibility evaluation of various hydrogen production facility development opportunities in FEI's Interior and Lower Mainland service areas. Review potential policy, regulatory and permitting requirements to offtake hydrogen from the production facilities, including	2.0	1.2

Activity	2023 ($ million)	2024 ($ million)
distribution in the natural gas distribution system, or supply hydrogen directly to industrial customers other than through the natural gas distribution system to replace natural gas. • 2024 – continue progress from 2023 with goal to reach Final Investment Decision on a commercial pilot.		
Hydrogen Offtake Supply Opportunities –2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Procurement Feasibility: • 2023 – continue evaluation of several potential third-party proposals that are considering developing projects to produce clean hydrogen for supply to offtakes such as FEI. Review regulatory and permitting requirements to offtake hydrogen from third-party production facilities for distribution in the natural gas distribution system, or supply hydrogen directly to industrial customers other than through the natural gas distribution system to replace natural gas. • 2024 – continue from 2023 with goal to advance one opportunity to definitive agreement.	0.1	0.1
Total	**2.1**	**1.3**

1
2

3

Hydrogen Distribution and Customer End-Use Service – 2023 Projected and 2024 Forecast Non-Labour Activities to Progress Gas System Hydrogen Readiness Assessment and Conversion:

- 2023 – FEI intends to select a preferred vendor and negotiate a contract to award the project to determine the overall requirements to distribute hydrogen in the gas system, address any end-use impacts, and customer and stakeholder education that will enable the safe distribution and customer end-use of hydrogen. The intent of the project is to enable hydrogen blending initially at relatively low percentage blend levels and increase the blend percentage over time in line with the provincial regulatory approval requirements.
- 2024 – FEI expects to commence the project in the first half of 2024 and it will run for a number of years.

Concurrent Hydrogen Development Enabling Initiatives – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Achieve Progress:

- 2023 and 2024 – continue progressing various concurrent activities including workforce education and training initiatives, engaging with technical regulators in BC, Canadian Standards Association (CSA), Canadian Gas Association, NRCan, and various other authorities having jurisdiction regarding various initiatives on hydrogen safety, codes and standards.

Hydrogen Demonstration Pilot Projects – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Preliminary Feasibility:

- 2023 and 2024 – continue to progress from preliminary feasibility to more detailed feasibility and project development for hydrogen blending projects that would blend hydrogen into a relatively small, isolated section of FEI's distribution system in the Interior and the Lower Mainland. Also continue engaging with multiple collaborators to advance preliminary feasibility and project definition for a hydrogen blending project that would blend hydrogen to replace natural gas use at an industrial site on Vancouver Island.

4

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6.23 Please provide an approximation of the number of years that hydrogen distribution and end use activities may require before they stabilize.

Response:

FEI expects that by 2030, BC, other provinces throughout Canada, North America, and the global gas industry will have achieved significant progress integrating hydrogen for mass market distribution and end-use applications in gas systems. At that point FEI considers it possible that research, feasibility work, testing, and a critical mass of successful pilot demonstration projects across the hydrogen value chain will have established the necessary codes, standards, and regulations to "stabilize" hydrogen distribution and end-use activities.

6.24 Please describe how blending hydrogen into the system would enable FEI to focus delivery to a specific industrial site.

Response:

Industrial blending refers to blending hydrogen and natural gas at a specific site. The hydrogen would be produced at the industrial site and, via a short hydrogen interconnect pipeline, the hydrogen would be injected and blended into the natural gas supply to the industrial site/customer.

6.25 Please describe why FEI is selecting to deliver hydrogen to an industrial site on Vancouver Island versus some other area served by its natural gas and hydrogen delivery system.

Response:

Please refer to the response to BCSEA IR1 7.20.

6.26 Please discuss in quantitative cost terms the costs of natural gas and the anticipated cost of hydrogen delivered by the FEI gas distribution system.

Response:

The cost difference between delivering natural gas and hydrogen on FEI's gas distribution system cannot be definitively quantified at this time. However, FEI expects that the major cost difference in the delivered cost between natural gas and hydrogen will relate to the evolving cost structure of the respective commodities over time. FEI currently acquires RNG (biomethane) supply and expects to acquire low-carbon intensity hydrogen supply that will compete with RNG and could ultimately reduce FEI's renewable gas supply portfolio long-run average price below $20 per GJ. Furthermore, carbon tax policy will increase the cost of conventional gas over time and it is possible that in the future the delivered cost of conventional gas including carbon tax could exceed the delivered cost of renewable gas (including hydrogen).

6.27 Please provide FEI's estimate of the energy in GJs delivered by natural gas at the pipeline distribution pressures per unit volume of delivered natural gas.

Response:

The energy in GJ delivered by natural gas at the pipeline distribution pressures per unit volume of delivered natural gas is approximately 0.036 MJ per standard cubic meter based on the lower heating value of natural gas and approximately 0.040 GJ per standard cubic meter based on the higher heating value of natural gas[9].

The volumetric energy density of delivering 100 percent hydrogen gas is approximately 0.013 GJ per standard cubic meter at the higher heating value of hydrogen and approximately 0.011 GJ per standard cubic meter at the lower heating value of hydrogen. Therefore, the energy content of a cubic meter of hydrogen is about 3 times lower compared to the energy content for natural gas at standard conditions (0 degree Celsius and 1 bar atmospheric pressure).

In theory, if FEI delivered 100 percent hydrogen at the existing gas distribution pressure, then the volume of hydrogen gas delivered per unit time (standard cubic meters per hour) would increase by a factor of three to account for the lower energy density of hydrogen gas compared to conventional gas. If FEI were to deliver hydrogen as a blend with conventional gas, the required increase in volumetric flowrate to deliver the necessary energy to meet customers' needs would be significantly lower compared to a conversion to 100 percent hydrogen gas.

An outcome from the increase in the volumetric flowrate with the introduction of hydrogen will be an increase in the pipeline velocity of the gas stream throughout the hydrogen-natural gas blended gas distribution system, a corresponding increase in the pressure drop across the hydrogen-natural gas blended gas distribution system, and a potential reduction in the ability of the gas distribution system to meet peak demand requirements. Previous analysis by FEI on

[9] https://www.fortisbc.com/services/commercial-industrial-services/natural-gas-price-market-curtailment-information.

select parts of the gas system indicated that the peak demand requirements of customers could likely be met without additional capacity upgrades required for relatively high blends of up to potentially nearly 50 percent by volume hydrogen blended with natural gas.[10] The previous analysis completed by FEI also indicated that, for higher percent blends up to 100 percent hydrogen, FEI may need to install some distribution system upgrades that would typically consist of installing short sections of distribution main looping that would reduce the pressure drop incurred as the gas flows through the system. FEI is planning to complete a system wide blending study for hydrogen in the gas system which will include a comprehensive examination of system capacity planning for the gas distribution system and identify any upgrades required to enable the introduction and increase of hydrogen as a blend with natural gas in the gas distribution system.

6.28 Please provide FEI's estimate of the energy in GJs delivered by hydrogen gas at the pipeline distribution pressures per unit volume of delivered hydrogen gas.

Response:

Please refer to the response to CEC IR1 6.27.

Table 6-11: Variable LNG Production O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Tilbury Plant:			
2	Labour	1.775	2.253	2.339
3	Materials	0.794	0.600	0.623
4	Contractor	0.637	0.230	0.239
5	Power	3.634	3.826	3.909
6	Fees and Employee Expenses	0.332	0.186	0.193
7	Sub-total	7.172	7.095	7.304
8	Mt. Hayes Plant			
9	Labour	0.339	0.360	0.374
10	Materials	0.028	0.025	0.026
11	Contractor	0.060	0.183	0.190
12	Power	0.261	0.236	0.241
13	Fees and Employee Expenses	0.000	0.000	0.000
14	Sub-total	0.687	0.804	0.831
15	Total O&M	7.859	7.899	8.135

[10] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/220509-fei-2022-ltgrp-ff.pdf?sfvrsn=cbf19584_0

6.29 Please provide the above data for projected 2023 and forecast 2024 divided by the anticipated volumes of LNG production and delivery, so that the costs per unit volume are clear.

Response:

Please refer to the following table for the requested information.

Table 1: Updated Table 6-11 with Anticipated Volumes of LNG and O&M per GJ of LNG ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Tilbury Plant:			
2	Labour	1.775	2.253	2.339
3	Materials	0.794	0.600	0.623
4	Contractor	0.637	0.230	0.239
5	Power	3.634	3.826	3.909
6	Fees and Employee Expenses	0.332	0.186	0.193
7	Sub-total	7.172	7.095	7.304
8	Mt. Hayes Plant			
9	Labour	0.339	0.360	0.374
10	Materials	0.028	0.025	0.026
11	Contractor	0.060	0.183	0.190
12	Power	0.261	0.236	0.241
13	Fees and Employee Expenses	0.000	0.000	0.000
14	Sub-total	0.687	0.804	0.831
15	Total O&M	7.859	7.899	8.135
16	Anticipated volumes of LNG production		2,700,000	2,700,000
17	Variable LNG Production O&M per gigajoule of LNG production		$ 2.93	$ 3.01

The anticipated volume of 2,700,000 GJ per year includes both LNG for sales and for storage and peak shaving. Fluctuations in unit costs may occur from year to year as the LNG sales business grows in volume and depending on how much LNG is used to support energy supply requirements in a given year. The unit cost may also fluctuate depending on changing resource requirements and cost inputs.

6.30 Please confirm that the power costs are for the production of LNG.

Response:

The power costs (i.e., electricity) are for the production of LNG and to operate the LNG facility, consistent with the treatment described (and approved) in the 2020-2024 MRP proceeding and Decision.

6.31 Please advise whether or not these costs are FEI forecasts or part of O&M formula.

Response:

As explained in Section 6.3 in the Application, all the O&M items included in Table 6-4, which includes Variable LNG Production O&M, are treated as Flow-through expenses under the approved MRP and are thus not part of the formula O&M.

6.32 Please confirm that FEI forecast costs incorporate FEI's inflation estimates but do not incorporate any expected productivity factor.

Response:

Generally speaking, FEI will incorporate into its forecasts any known or estimated impacts of inflation and any known or estimated savings due to increased productivity or other factors that may be applicable. However, as FEI's forecast costs are not subject to the I-X formula, they do not incorporate a "productivity factor" per se.

CAPITAL EXPENDITURES (AS PROVIDED FOR BY THE CAPITAL FORECAST WITH FEI'S GROWTH CAPITAL DETERMINED BY THE INDEXING FORMULA), PLUS OTHER ITEMS FORECAST ANNUALLY (SECTION 7)

7. Reference: Exhibit B-2, Page 59, Page 60, Page 61, Page 63, Page 67

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula Growth Capex	87.531	87.531	54.639	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	183.850	183.850	181.880	Section 11, Schedule 4, Lines 16 + 17
3	Flow through Capex	64.992	31.117	48.939	Section 11, Schedule 4, Sum of Lines 13 to 15
4	Total Gross Regular Capex	336.373	302.498	285.458	Sum of Line 1 to 3; Section 11, Schedule 4, Line 20
5	Less: Formula CIAC	(2.453)	(2.453)	(2.388)	Section 11, Schedule 9, Line 2
6	Less: Forecast CIAC	(4.342)	(4.342)	(12.542)	Section 11, Schedule 9, Line 3 to 5
7	Net Regular Capex	329.578	295.703	270.528	Sum of Line 4 to 6

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Table 7-2: Calculation of 2024 Formula Growth Capital ($ millions)

Line No.	Description	Forecast 2024	Reference
1	Prior Year Base Unit Cost Growth Capital	4,205	G-352-22 and Section 11, Schedule 4, Line 2
2	Net Inflation Factor	3.854%	Section 11, Schedule 3, Line 9, Column 7
3	Current Year Unit Cost Growth Capital	4,367	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast	15,000	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	65.505	Line 3 x Line 4 / 1,000,000
6	2022 Growth Capital True-up	(14.254)	Line 16
7	Formulaic CIAC	2.388	Section 11, Schedule 9, Line 2, Column 5
8	System Extension Fund	1.000	G-338-20 SEF Decision
9	Gross Formula Growth Capex	54.639	Sum of Line 5 to Line 8
10			
11	2022 Growth Capital True-up		
12	2022 Actual Gross Customer Addition	16,477	Section 2, Table 2-3
13	2022 Forecast Gross Customer Addition	20,000	G-366-21 2022 FEI Annual Review Decision
14	Difference	(3,523)	Line 12 - Line 13
15	2022 Unit Cost Growth Capital ($/customer)	4,046	G-366-21 2022 FEI Annual Review Decision
16	Growth Capital True-up in 2023	(14.254)	Line 14 x Line 15 / 1,000,000

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7.1 Please confirm that the Prior Year Base Unit Cost Growth Capital $4,205 is for 2023 and the Unit Cost growth Capital $/customer is for 2022, meaning that true up is occurring over a two-year period.

Response:

Confirmed. The Prior Year Base Unit Cost Growth Capital of $4,205 (i.e., Line 1 of Table 7-2 in the Application) is the unit cost for 2023, which is inflated by the net inflection factor of 3.854 percent to calculate the unit cost growth capital for 2024 (i.e., $4,367 on Line 3 of Table 7-2).

FEI also confirms the Unit Cost Growth Capital ($/customer) of $4,046 (i.e., Line 15 of Table 7-2) is the unit cost for 2022. FEI notes that the true-up of formula growth capital can only be calculated once the *actual* gross customer additions are known, which at the time of the Application, is the 2022 actual gross customer additions (i.e., from two years prior).

7.2 Please confirm that true up returns growth overestimates in 2022 to the benefit, impacting rates, of customers 2 years after the over estimating took place.

Response:

As noted in the response to CEC IR1 7.1, the true-up can only be calculated once the actual gross customer additions are known. The true-up is based on actual customers compared to forecast customers and may create either a delivery rate surplus or deficiency for customers, depending on the direction of the true-up. In the case of the 2022 true-up provided in this Application, the true-up resulted in a decrease to the overall revenue deficiency required to be collected in 2024 delivery rates.

7.3 Please confirm that during this time FEI had the use of the capital represented by the gross customer additions not realized $14,254,000.

Response:

Not confirmed. FEI collected the cost of service amounts (i.e., earned return and taxes) related to the $14.254 million in its 2022 delivery rates, not the $14.254 million itself. Variances between the actual and forecast cost of service amounts related to Growth Capital for 2022 and 2023 (which would also include depreciation related to the 2022 capital additions) are then recorded in the earnings sharing deferral account and returned to or recovered from customers in subsequent years. Once the true-up occurs in 2024 delivery rates, it would be expected that no cost of service variances related to the 2022 customer variance would remain and customers would be paying for the actual cost of service, at the approved unit cost, from 2024 onwards until actuals are re-based within the forecast.

7.4 Please confirm that at a 5.5% weighted cost of capital this would have a time value of approximately $1,500,000, which is a utility cost of capital benefit over time and at a customer cost of capital it would likely be a higher value.

Response:

FEI is unable to confirm the calculation by the CEC on time value.

FEI does not include the time value of funds as part of the growth capital true-up calculation. FEI notes that the true-up is symmetrical and FEI also does not consider the time value of the funds when the forecast of gross customer additions is less than actuals. While the true-up for the 2022 growth capital is for an over-forecast of gross customer additions in 2022, the true-up of the 2021 growth capital included in the Annual Review for 2023 Delivery Rates was in the opposite direction and resulted in an additional $16.798 million of growth capital in 2023.

7.5 Please confirm that the formula process does not recognize the time value of funds where true ups are being made.

Response:

Please refer to the response to CEC IR1 7.4.

Table 7-3: Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Sustainment Capital	129.336	129.336	130.628	Section 11, Schedule 4, Line 16
2	Other Capital	54.514	54.514	51.252	Section 11, Schedule 4, Line 17
3	Total	183.850	183.850	181.880	Line 1 + Line 2

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7.6 Please confirm that the forecast capital (sustainment and other) is stable from 2023 to 2024.

Response:

FEI interprets “stable” to mean the change between the 2023 Approved and 2024 Forecast sustainment and other capital is small, and agrees with the CEC’s characterization on this basis.

7.7 Please provide the last 5 years 2018, 2019, 2020, 2021, 2022 for this forecast and the actuals.

Response:

Please refer to Table 1 below for the actual and forecast Sustainment and Other capital expenditures. For 2018 and 2019, FEI's overall amount of Sustainment and Other capital was determined annually by formula as part of the 2014-2019 PBR Plan. Therefore, FEI did not distinguish the formula amount between the two categories.

Table 1: Summary of FEI's Sustainment and Other Capital from 2018 to 2022

	2018		2019		2020		2021		2022	
$ millions	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**
Sustainment Capital	N/A	115.210	N/A	109.187	111.530	112.405	112.944	115.763	117.106	124.653
Other Capital	N/A	43.997	N/A	44.693	49.770	50.745	49.916	50.246	46.474	46.560
Total	114.597	159.207	117.109	153.880	161.300	163.150	162.860	166.009	163.580	171.213

Table 7-4: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Pension/OPEB (Growth Capital Portion)	1.034	1.034	0.871	Section 11, Schedule 4, Line 13
2	Biomethane Assets	58.571	29.583	43.068	Section 11, Schedule 4, Line 14
3	NGT Assets	5.387	0.500	5.000	Section 11, Schedule 4, Line 15
4	Forecast Regular Capex	64.992	31.117	48.939	Sum of Lines 1 through 3

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7.8 Please explain why the projected for 2023 for NGT Assets is so much lower than the approved amount.

Response:

As explained on page 62 of the Application, the lower 2023 Projected NGT capital expenditures compared to 2023 Approved is due to the delay of the Tilbury T1A truck load-out project.

7.9 Please confirm that there is no true-up process for flow through capital overestimates but that rates would have been set in 2023 on the basis of the approved flow through forecast for capital expenditures.

Response:

Not confirmed. The approved Flow-through deferral account captures, among other things, the revenue requirement impact of the variances between approved and actual flow-through capital expenditures. These variances are then recovered from or returned to customers in the following

year through amortization of the Flow-through deferral account. Please refer to Section 12.4.2.2 of the Application for further information on the Flow-through deferral account.

7.10 Please confirm that capital expenditures forecast which are not made would not be in the rate base and would be replaced by actuals when the actuals are realized.

Response:

Confirmed. However, FEI notes that for capital expenditures that are approved to be treated as flow-through as well as CPCN and Major Projects, the cost of service impact due to the variances between actual and forecast expenditures will be captured by the Flow-through deferral account and recovered from or returned to customers through amortization in the following year. For FEI's regular capital (i.e., growth, sustainment, and other capital), the cost of service impacts of variances between formula/forecast and actual capital expenditures are subject to the earnings sharing mechanism.

Table 7-5: Biomethane Capital Expenditures ($ millions)

Line No.	Description	BCUC Order	Approved 2023	Projected 2023	Forecast 2024
1	Kelowna	E-19-12	-	0.250	0.500
2	REN Energy	G-60-20	-	-	0.500
3	Foothill LF (RDFFG)	E-2-22	10.000	2.000	2.000
4	Dickland Farms	E-13-20	-	0.700	-
5	Capital Regional District	E-15-21	3.000	7.000	3.000
6	City of Vancouver	G-235-19	21.771	17.533	16.613
7	Net Zero Waste	E-21-21	1.000	-	5.000
8	Delta RNG	E-3-22	6.000	1.500	4.205
9	Comox Valley LF	To be filed	10.800	0.500	2.000
10	Andion - Semiahmoo	To be filed	2.000	0.100	2.000
11	Vernon LF	To be filed	4.000	-	2.000
12	Fraser Valley Biogas Expansion	To be filed	-	-	4.250
13	Ecowaste	To be filed	-	-	1.000
14	**Total Biomethane CAPEX**		**58.571**	**29.583**	**43.068**

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7.11 Please confirm that the approved capital expenditures for biomethane are used in the setting of rates for 2023 and whatever the actuals are (anticipated to be more in line with the projected expenditures) will be in the rate based as actual spend occurs.

Response:

Confirmed. However, all biomethane related costs and revenues, including the cost of service impact due to the biomethane projects, are transferred to the Biomethane Variance Account (BVA) with the balance recovered from customers through the BERC and the BVA rate rider. Additionally, FEI notes the variance between forecast and actual amounts will be captured in the BVA and will be recovered from or returned to customers through the BVA rate rider.

> 2024. FEI notes the Tilbury T1A truck load-out is a Prescribed Undertaking under the GGRR;[41] as such, the capital estimates provided here are not being requested for approval as part of the annual review process, but are provided to include the current estimates for NGT Assets capital expenditures in customer rates.

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7.12 Please confirm that the bankruptcy would not be part of a Prescribed Undertaking and the cost of delay and the potential recoveries under the bankruptcy would be FEI responsibilities and hence customer costs and benefits, if any.

Response:

The prescribed undertaking set out in section (3)(a)(ii) of the GGRR is as follows:

> The public utility, before March 31, 2022, enters into a binding commitment to construct and operate, or purchase and operate, one or more tanker truck load-outs for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas or to owners or operators of marine vehicles that operate on liquefied natural gas.

FEI entered into a binding contract for the Tilbury T1A truck load-out project prior to March 31, 2022, and the project is thus a prescribed undertaking. The bankruptcy of the contractor is not relevant to the project being a prescribed undertaking.

The contract is a binding “lump-sum” contract, which includes a labour and materials bond, and a performance bond. FEI expects that these bonds will cover any incremental capital costs due to the bankruptcy, and that the bankruptcy will not have any impact on the capital costs of the Tilbury T1A truck load-out.

Table 7-7: Reconciliation of 2024 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	2024 Forecast	Reference
1	Formula Growth Capex	54.639	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	181.880	Section 11, Schedule 4, Line 16 + Line 17
3	Flow through Capex	48.939	Section 11, Schedule 4, Sum of Line 13 to Line 15
4	Total Gross Regular Capex	285.458	Sum of Line 1 to 3
5	Capitalized Overheads	59.233	Section 11, Schedule 5, Line 21
6	AFUDC	9.526	Section 11, Schedule 5, Line 22
7	Change in Work in Progress	20.404	Section 11, Schedule 5, Line 24
8	Total Regular Additions to Plant	**374.621**	Sum of Line 4 to 7
9			
10	Special Projects and CPCN Capex		
11	Tilbury Expansion Project	3.959	Section 11, Schedule 5, Line 7
12	IGU Project	20.721	Section 11, Schedule 5, Line 9
13	CTS-TIMC Project	63.107	Section 11, Schedule 5, Line 10
14	AMI Project	55.000	Section 11, Schedule 5, Line 12
15	LMIPSU	0.006	Section 11, Schedule 5, Line 8
16	PGR	0.153	Section 11, Schedule 5, Line 11
17	AFUDC	7.166	Section 11, Schedule 5, Line 28
18	Change in Special Projects and CPCN Work in Progress	(87.927)	Section 11, Schedule 5, Line 30
19	Total Special Projects and CPCN Additions to Plant	**62.185**	Sum of Line 11 to 18
20			
21	Total Plant Additions	**436.806**	

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7.13 Please confirm that changes for the work in progress are adjustments to previously forecast capital expenditures for formula capital and special projects and CPCN expenditures.

Response:

Not confirmed.

To clarify, the change in work in progress is calculated as the difference between the forecast 2024 ending work in progress balance and the projected 2024 opening work in progress balance. The 2024 opening work in progress balance includes actuals and newly projected amounts up until December 31, 2023 for flow-through items only. Non-flow-through amounts are not trued-up for actuals and are based on original forecasts.

The Change in Work in Progress amount shown on Line 7 in Table 7-7 of the Application is calculated as the change between the regular capital expenditures work in progress, which includes both formula and forecast capital.

The Change in Work in Progress amount shown on Line 18 in Table 7-7 is a similar calculation, but for Major/Special Projects and CPCNs only.

7.14 Please confirm that these adjustments are reflecting the actual expenditures for the prior year.

Response:

Please refer to the response to CEC IR1 7.13.

FINANCING AND RETURN ON EQUITY (SECTION 8)

8. Reference: Exhibit B-2. Page 77

> The 3-month T-Bill forecast for 2024 is 4.27 percent, which is an increase from the 3.14 percent approved in 2023. FEI continues to face a rising interest rate environment due to high inflation and the Bank of Canada continuing to raise its policy interest rate in an attempt to slow economic growth and reduce core inflation. While the inflation in Canada eased to 3.40 percent in May 2023 from a high of 8.10 percent from a year ago, the downward movement was driven largely by lower energy prices rather than easing underlying inflation. The Bank of Canada's

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8.1 Please confirm that as the interest rates rise and underlying inflation continues to be an issue that FEI might expect this to have a continuing impact on new housing starts and commercial customer starts, which may have impacts of new gross customers and on net customer additions.

Response:

Higher financing costs all things equal can negatively affect housing starts as fewer buyers would be able to afford a home. All things equal, builders would then build fewer homes resulting in a smaller pool of potential customer attachments which would translate in a reduction in gross and net customer additions in the future. However, other factors, such as immigration, can have an opposite effect on housing starts and the Lower Mainland has experienced significant immigration over the last few years.

PLANT BALANCES, DEFERRAL ACCOUNT BALANCES AND OTHER RATE BASE INFORMATION AND DEPRECIATION AND AMORTIZATION TO BE INCLUDED IN RATES. (SECTION 7 & 12)

9. Reference: Exhibit B-2, Page 67

> Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance net of CIAC, the 2024 depreciation expense is calculated as $219.593 million.[47]
>
> [47] $228.416 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $8.823 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

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FORTISBC ENERGY INC. — FEI Annual Review for 2024 Rates - July 28, 2023 — Section 11

DEPRECIATION AND AMORTIZATION EXPENSE FOR THE YEAR ENDING DECEMBER 31, 2024 ($000s) — Schedule 21

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 223,974	$ 232,095	$ 8,121	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(821)	(793)	28	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(2,540)	(2,886)	(346)	Schedule 7.2, Line 37, Column 7
5		220,613	228,416	7,803	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 95,782	$ 125,283	$ 29,501	Schedule 11.1, Line 29, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(55)	(54)	1	Schedule 11.1, Line 30, Column 6
10	Non-Rate Base Deferrals	19,237	8,783	(10,454)	Schedule 12, Line 30, Column 6
11	CIAC	(8,753)	(8,851)	(98)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		106,239	125,189	18,950	
14					
15	Total	$ 326,852	$ 353,605	$ 26,753	

9.1 Please provide the deferral amortization periods for each of the deferral accounts in Schedules 11 and 11.1. set out beside the name of the deferral account.

Response:

Please refer to the table below for the amortization periods for each of the deferral accounts in Schedules 11 and 11.1.

Deferral Account	Approved Deferral Amortization Period (Years)
Forecasting Variance Accounts	
Midstream Cost Reconciliation Account (MCRA)	2 (MCRA Rate)
Commodity Cost Reconciliation Account (CCRA)	1 (CCRA Rate)
Revenue Stabilization Adjustment Mechanism (RSAM)	2 (Rider 5)
Interest on CCRA	2 (MCRA Rate)
Interest on MCRA	1 (CCRA Rate)
Interest on RSAM	2 (Rider 5)
Interest on Gas Storage	3
SCP Mitigation Revenues Variance Account	2
Pension & OPEB Variance	3
BCUC Levies Variance	1
Rate Smoothing Accounts	
Benefits Matching Accounts	
Demand-Side Management (DSM)	10
NGV Conversion Grants	5
Emissions Regulations	1
Greenhouse Gas Reduction Regulation Incentives	10
CNG and LNG Recoveries	1
2025 Multi-year Rate Plan Application	TBD
BCUC Initiated Inquiry Costs	1
PGR Application and Preliminary Stage Development Costs	3
Transportation Service Report	TBD
2021 Generic Cost of Capital Proceeding	TBD
2023 DSM Expenditures Schedule Application	1
City of Coquitlam Application Proceeding	1
2024-2027 DSM Expenditures Schedule Application	4 (Requested)
2023 Cost of Service Allocation Study	TBD
AMI Application and Feasibility Costs	3
Whistler Pipeline Conversion	20
Gas Asset Records Project	5
Gains and Losses on Asset Disposition	10
Net Salvage Provision/Cost	Based on the removal provision each year
PCEC Start Up Costs	40
2022 Long Term Gas Resource Plan Application	TBD
2020–2024 MRP Application	5
2021 Renewable Gas Program Comprehensive Review	TBD
GCU Preliminary Stage Development Costs	3
Transmission Integrity Management Capabilities	5
Annual Review of 2020-2024 Rates	1
FEFN - Common Rates and 2022 Revenue Requirement Application Costs	1
Retroactive Expense Accounts	
Other Accounts	
Pension & OPEB Funding	N/A
US GAAP Pension & OPEB Funded Status	N/A
BVA Balance Transfer	1 (Rider 3)
COVID-19 Customer Recovery Fund	3
Stargas Assets Acquisition Deferral Account	1
PST Rebate on Select Machinery and Equipment	1 (Requested)
Residual Delivery Rate Riders	1
FEFN - Transitional Balance	1

1

PROJECTED EARNINGS SHARING FOR THE CURRENT YEAR AND TRUE-UP TO ACTUAL EARNINGS FOR THE PRIOR YEAR AND RATE RIDERS (SECTION 10)

10. Reference: Exhibit B-2, Page 85, Page 88, Page 90 and Page 92

> FEI proposes to distribute $6.989 million to customers in 2024 as a reduction in 2024 revenue requirements through amortization of the projected 2024 opening after-tax balance and 2024 financing of $5.102 million in the MRP Earnings Sharing deferral account.
>
> As part of future rate filings, the actual earnings sharing for 2023 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2023 ROE variance from approved.

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10.1 Please confirm that the earnings sharing FEI is anticipating arises from the 2023 earnings.

Response:

Not confirmed. As stated in Section 10.2 of the Application, the majority of the amount FEI is proposing to distribute to customers in 2024 is related to the true-up between 2022 Actual earnings sharing of $4.579 million and the 2022 Projected earnings sharing of zero. The remaining amounts to be returned to customers in 2024 relate to financing costs on the deferral.

FEI is projecting 2023 earnings sharing of zero in this Application. The actual 2023 earnings sharing will be calculated and proposed to be returned to customers in a future rate filing. This approach is consistent with the treatment in the previous years of the MRP term.

10.2 Please confirm that this distribution is awaiting a Commission decision on the Generic Cost of Capital hearing, which may impact the FEI earnings for that period.

Response:

Not confirmed. The impacts of the BCUC's decision on Stage 1 of the Generic Cost of Capital proceeding do not impact the earnings sharing calculation.

Table 10-2: 2022 BVA Rate Rider Calculation

Line No	Particulars	BVA Rider Projected 2023 ($000s) Net of Tax	BVA Rider Projected 2023 ($000s) Grossed Up	Non-Bypass Forecast 2024 Vol (TJ)
1	**BVA Rider Account Balance**			
2	**BVA Balance Transfer Deferral Account Balance Dec 31, 2022 - Actual**	18,355.0	$ 25,143.8	
3	Less Projected 2023 BVA Rider recoveries for 2022 using 2023 Projected Non-bypass volumes	(19,228.7)	(26,340.6)	
4	**2023 projected true up adjustment - 2022 projected recovery variance**	(873.7)	(1,196.8)	
5	BVA Balance transferred to BVA Balance Transfer Deferral Account Dec 31, 2023 - Projected	27,422.2	$ 37,564.7	
6	**BVA Balance Transfer Deferral Account Balance Dec 31, 2023 - Projected**	**26,548.6**	**36,367.9**	**201,033.8**
7				
8	**Residential**			
9	Rate Schedule 1		$ 15,083.5	83,378.5
10	**Commercial**			
11	Rate Schedule 2		$ 5,369.0	29,678.8
12	Rate Schedule 3		$ 4,884.8	27,002.0
13	Rate Schedule 23		$ 658.0	3,637.1
14	**Industrial**			
15	Rate Schedule 4		$ 32.1	177.7
16	Rate Schedule 5		$ 2,147.4	11,870.1
17	Rate Schedule 6		$ 3.3	18.1
18	Rate Schedule 7		$ 1,230.0	6,799.4
19	Rate Schedule 22- Firm Service		$ 1,889.5	10,444.7
20	Rate Schedule 22- Interruptible Service		$ 2,962.1	16,373.7
21	Rate Schedule 25		$ 1,406.9	7,777.0
22	Rate Schedule 27		$ 701.3	3,876.7
23				
24	**Total BVA Rider (Non-Bypass)**		**$ 36,367.9**	**201,033.8**
25				
26	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.181**	

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10.3 Please provide the BVA rate rider as a percent of the rates per GJ for each customer rate schedule.

Response:

Please refer to Table 1 below for the BVA rate rider as a percent of the total effective rate per GJ (including delivery, commodity, midstream, and rate riders) by sales customer rate schedule (i.e., RS 1 to 7). FEI has excluded transportation customers as FEI does not have insight into the commodity charge portion of their total bills.

Table 1: BVA Rate Rider as a Percent of the Total Effective Rate per GJ by Rate Schedule

	2024 Proposed BVA Rider ($/GJ)	2024 Total Proposed Effective Rate ($/GJ)	% of BVA Rider over Total Effective Rate
Rate Schedule 1	0.181	12.908	1.40%
Rate Schedule 2	0.181	10.697	1.69%
Rate Schedule 3	0.181	9.128	1.98%
Rate Schedule 4	0.181	6.838	2.65%
Rate Schedule 5	0.181	7.478	2.42%
Rate Schedule 6	0.181	7.640	2.37%
Rate Schedule 7	0.181	6.166	2.94%

Table 10-4: RNG Customers by Rate Schedule

2023 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short Term	
Rate Schedule 1B	11,586
Rate Schedule 2B	297
Rate Schedule 3B	57
Rate Schedule 11B	2
Rate Schedule 5B	18
Rate Schedule 30 Off System	-
Long Term	
Rate Schedule 11B	4
Total	**11,964**

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10.4 Please show for each rate schedule the total customers for the rate schedule and the percentage of customer enrollment for the rate class.

Response:

Please refer to Table 1 below for the percentage of customer enrollments by rate class. FEI notes that the 11,964 customer enrollments shown in Table 10-4 of the Application was the projection from Q1 2023. As noted in the response to BCSEA IR1 10.1, FEI is now projecting (as of August 2023) approximately 12,500 customer enrollments to the end of 2023.

Table 1: Percent of RNG Customer Enrollment by Rate Class

	2023 Projected Customer Enrollment	Average Customer Count	% of Enrollment
Short Term			
Rate Schedule 1B	11,586	989,825	1.2%
Rate Schedule 2B	297	90,551	0.3%
Rate Schedule 3B	57	7,234	0.8%
Rate Schedule 11B	2	971	0.2%
Rate Schedule 5B	18	677	2.7%
Rate Schedule 30 Off System	-	-	0.0%
Long Term			
Rate Schedule 11B	4	971	0.4%

The collection of the $0.40 per month innovation rider commenced on August 1, 2020 and is forecast to collect approximately $5.229 million in 2024 based on the forecast average non-bypass customer count for 2024.

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10.5 Please confirm that the $.40 per month is collected from customers on the basis of a per customer rider.

Response:

Confirmed.

REVIEW OF EXOGENOUS EVENTS THAT THE COMPANY OR STAKEHOLDERS HAVE IDENTIFIED THAT SHOULD BE PUT FORWARD TO THE BCUC FOR REVIEW

11. Reference: Exhibit B-2, Page 136, Page 142 and Page 143

Table 12-1: Breakdown of Flooding Repair Costs Insurance Claim

Zone/Department	City/Region		Damage/Loss Claim
Zone 3	Abbotsford	$	772,804
Zone 4	Merritt	$	745,888
Zone 5	Princeton	$	667,513
Zone 6	Roberts Creek	$	431,147
Engineering	Across all regions above	$	111,951
Transmission	Across all regions above	$	178,218
Customer Service	Across all regions above	$	826,139
Total Claim Submission		**$**	**3,733,660**

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11.1 Please confirm that Table 12-1 above does not show the deductible which FEI would be seeking to recover from customers.

Response:

FEI confirms the table does not include the $1 million insurance deductible.

FEI clarifies that if its insurance claim is successful, the net incremental costs would be limited to the $1 million insurance deductible. However, until the insurance claim has been settled, FEI will not know the total cost related to the flooding, as FEI may receive all, partial or no reimbursement. When the insurance claim has been settled, FEI will determine if exogenous factor treatment is warranted and will file for approval of exogenous factor treatment.

11.2 Please confirm that the balance of the claim for insurance over and above the deductible would only become an exogenous issue if the insurance does not cover all of the cost claim submission above the deductible.

Response:

Please refer to the response to CEC IR1 11.1.

11.3 Please discuss whether or not in providing the damage/loss claim FEI has added appropriate overheads to its costs for repair and recovery.

Response:

FEI interprets the reference to appropriate overheads in the question to mean fully loaded labour rates. FEI has included all applicable flood damage repair costs, including fully loaded labour rates, in its claim submission to its insurers. FEI's claim submission is based on its interpretation of the terms of the insurance policy which covers recoverable costs in the event of flood damage to FEI's assets. Actual amounts recoverable from the insurers continues to be in negotiation.

Table 12-4: 2023 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars (1)	2023 Approved (2)	2023 Projected (3)	After-Tax Flow-Through Variance (4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (643.916)	$ (645.472)	$ (1.556)
3	Commercial (Rate 2, 3, 23)	(294.040)	(301.191)	(7.151)
4	Industrial (All Others)	(140.388)	(133.738)	6.650
5				
6	**Net O&M Expense**			
7	Pension & OPEB	9.577	9.577	-
8	Insurance	12.242	12.406	0.164
9	Biomethane	5.237	5.075	(0.162)
10	NGT	1.937	2.412	0.475
11	Variable LNG Production Costs	7.859	7.899	0.040
12	Integrity O&M	8.000	9.000	1.000
13	Renewable Gas Development	2.000	3.069	1.069
14	BCUC Levies	8.493	8.493	-
15	Biomethane O&M transferred to BVA	(5.237)	(5.075)	0.162
16	Capitalized Overhead	(56.744)	(56.744)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	114.964	114.964	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	79.144	77.785	(1.359)
24				
25	**Other Revenues**			
26	Tilbury insurance proceeds	-	(6.135)	(6.135)
27	SCP Third Party Revenue	(13.286)	(13.286)	-
28	NGT Tanker Rental Revenue	(0.926)	(1.008)	(0.082)
29	Biomethane Other Revenue	(0.512)	(1.069)	(0.557)
30	LNG Capacity Assignment	(18.039)	(18.039)	-
31	CNG & LNG Service Revenues	(3.261)	(3.215)	0.046
32				
33	**Interest Expense**			
34	Long-term debt interest expense variance	159.754	153.500	(6.254)
35	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Short-term debt rate variance	-	6.644	6.644
37	Short-term debt volume variance from long-term debt issue variance	-	8.266	8.266
38	Short-term debt timing variance from long-term debt issue timing	-	-	-
39				
40	**Income Tax Expense**			
41	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
42	Income tax/CCA rate changes	-	-	-
43	Income tax on taxable flow-through variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(0.340)	(0.340)
44				
45	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**0.920**
46				
47	2022 Ending Deferral Account Balance True-up			11.837
48	2023 Financing True-up			0.670
49	2024 Financing Addition to Deferral Account			0.357
50				
51	**2024 After-Tax Amortization**			**13.784**

11.4 Please confirm that the true up of $11,837,000 is the final adjustment from 2022 and no other items from 2022 are outstanding to be resolved by flow through to customers.

Response:

Confirmed.

REVIEW OF THE UTILITY PERFORMANCE WITH RESPECT TO SQIS THAT SHOULD BE REVIEWED IN FUTURE ANNUAL REVIEWS (SECTION 13)

12. Reference: Exhibit B-2, Page 146

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2022 Results	2023 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	97.7%	97.6%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	97.1%	97.7%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<= 2.08	2.95	1.59	1.72
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 8	12	6	4
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	78%	77%
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	1.0	0.63
Meter Reading Accuracy	Number of scheduled meters that were read	>= 95%	92%	88%	95%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	62%	67%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	98.5%	98.9%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.6	8.5
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	106	88
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	3	0
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0058	0.0034

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12.1 Please explain what caused the scheduled meters reading accuracy to dip to 88% in 2022.

Response:

Please refer to the response to BCUC IR1 19.2.

12.2 Please advise if FEI would consider developing a cost-effectiveness SQI measuring the percentage improvement in the cost effectiveness of FEI some specific functions FEI would choose to monitor.

Response:

FEI does not consider that developing a cost-effectiveness SQI would be appropriate.

The purpose of SQIs under the 2020-2024 MRP framework is to monitor the quality of service provided across a broad range of business processes in areas important to the customer experience. Further, the SQIs are used to monitor FEI's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

Measurement of cost-effectiveness is inherently built into the MRP through the approved inflation-index unit cost approach to determining formula O&M funding which incorporates an annual 0.5 percent Productivity Improvement Factor (PIF) as approved by the BCUC in the MRP Decision and Order G-165-20. In the MRP Decision (page 62), the BCUC stated the following:

> The Panel finds that a 0.5 percent X-Factor recognizes the Utilities' efficiency efforts over the past six years and also considers the interests of ratepayers by providing a reasonable challenge to the Utilities to continue to identify efficiency opportunities which benefit all parties.

FEI considers this high-level approach to encouraging cost efficiency and effectiveness and where FEI is provided the flexibility to work within an overall O&M spending envelope (i.e., indexed based formula O&M funding) has worked well for both the Company and its customers in the current MRP and in the prior 2014-2019 PBR Plan.