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July 24, 2026

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Dear Registrar:

Re: FortisBC Energy Inc. (FEI)

Rate Setting Framework for the Years 2025 to 2027 approved by British Columbia Utilities Commission (BCUC) Order G-69-25 (Rate Framework)

Annual Review for 2027 Delivery Rates

In accordance with the Rate Framework and BCUC Order G-150-26 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2027 Delivery Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FEI 2025 and 2026 Annual Review of Delivery Rates proceeding

FortisBC Energy Inc.

Rate Setting Framework for 2025 through 2027

Annual Review for 2027 Delivery Rates

July 24, 2026

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Energy Inc. (FEI or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Decision and Order G-69-25, which approved a Rate Setting Framework (RSF or Rate Framework) for FEI for the years 2025 to 2027 (RSF Decision). In accordance with the RSF Decision, an Annual Review process is required to set rates for each year of the RSF. With the filing of this Application, FEI seeks to commence the Annual Review process to set permanent delivery rates for 2027.

The proposed delivery rates for 2027 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2025 earnings sharing to customers, result in a 3.43 percent delivery rate increase from 2026 delivery rates. For an average residential customer,[1] the increase in the delivery component of the total bill will result in an annual bill impact of approximately $31.32 or 2.44 percent. After consideration of the delivery rate riders, the annual bill impact is an increase of approximately $48.78 or 3.80 percent.

In the subsections below, FEI sets out its approvals sought and provides an overview of the requirements for the Annual Review process. This is followed by a summary of FEI's proposed revenue requirements and delivery rate changes for 2027 as well as a summary of the service quality indicator (SQI) results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

FEI requests BCUC approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2027 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2027, as filed in the Application and subject to any adjustments identified by FEI during the regulatory process and any directives or determinations made by the BCUC in its decision on the Application.
2. Approval to establish the following rate base deferral accounts to capture the costs associated with regulatory processes, as described in Section 7.6.1:
    - 2028+ Rate Setting Application deferral account, with the amortization period to be determined in a future proceeding;

[1] Based on consuming approximately 90 gigajoules (GJ) per year.

- 2026 Long-Term Gas Resource Plan (LTGRP) deferral account, with a 3-year amortization period commencing January 1, 2027; and
- 2026 Main Extensions (MX) Policies Review deferral account, with a 1-year amortization period commencing January 1, 2027.

3. Approval to record the actual after-tax costs of the 2026 equity issuance in the Flotation Costs deferral account.
4. Approval to set the 2027 Revenue Stabilization Adjustment Mechanism (RSAM) rate rider at $0.406 per GJ, as set out in Table 10-1 of Section 10.3.1.

A draft order is included in Appendix C.

1.3 *Requirements for the Annual Review*

On page 73 of the RSF Decision, the BCUC Panel stated that the Annual Review process should continue in the Rate Framework and that the content (list of items) set out in the 2020-2024 MRP Decision (page 167) remains appropriate. For reference, the table below sets out each requirement and FEI's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	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
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10.2
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	N/A. For the term of the RSF, the BCUC approved FEI's request to remove the Efficiency Carryover Mechanism (ECM).

Item	Description	Response or Reference
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FEI does not have any recommendations at this time.
6	Reporting on the Innovation Fund status.	Section 10.3.3
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FEI does not have any recommendations at this time.

1.4 *REVENUE REQUIREMENT AND DELIVERY RATE CHANGE FOR 2027*

FEI has calculated the 2027 revenue requirement using a combination of the approved formulas for O&M and Growth capital, the approved forecasts for Sustainment/Other capital from the RSF Decision, and the 2027 Forecast amounts for items that are forecast annually.

The revenue requirement components for 2027 set out in the Application result in a revenue deficiency of $45.920 million which is equivalent to an effective delivery rate increase of 3.43 percent from the 2026 Approved delivery rates.

The following chart summarizes the items that contribute to the 2027 revenue deficiency. The chart shows the items that increase the deficiency in yellow and the items that decrease the deficiency in green. The 2027 deficiency of $45.920 million is then the sum of all the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2027 Delivery Revenue Deficiency ($ millions)

Each of the categories is discussed briefly below.

1.4.1 Demand Forecast (Section 3)

For 2027, FEI is forecasting total demand to be approximately 218.2 PJ, which is a reduction of approximately 4.0 PJ (or 1.8 percent) from the 2026 Approved level. The decrease is primarily due to forecast decreases from residential customers in Rate Schedule (RS) 1, large commercial customers in RS 3, and large volume transportation customers in RS 22. These decreases are partially offset by significant growth in liquefied natural gas (LNG) demand under RS 46, which increased by approximately 2.4 PJ (or 69.5 percent) from the 2026 Approved level. Overall, the decrease in 2027 Forecast demand contributes approximately $6.406 million to the 2027 revenue deficiency when calculated based on the 2026 Approved rates.

1.4.2 Other Revenue (Section 5)

Other Revenue is forecast to decrease by approximately $0.292 million which has a small contribution to the 2027 deficiency. The decrease is primarily due to a forecast reduction in natural gas for transportation (NGT) related recoveries.

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

FEI establishes the majority of its O&M costs by formula during the RSF term. The 2027 Formula O&M is $329.218 million, which incorporates a net inflation factor of 1.901 percent, and the 2027 forecast average customer count of 1,113,600. The 2027 Formula O&M is approximately $5.113 million[2] or 1.6 percent higher than the approved 2026 Formula O&M of $324.105 million.

For the 2027 O&M forecast outside of the formula, FEI is forecasting an amount of $94.180 million, which is approximately $2.859 million[3] or 3.1 percent higher than the 2026 Approved level. The drivers of the increase are pension and other post-employment benefits (OPEB) expense, integrity O&M and increased expenditures for Clean Growth Initiatives, which are partially offset by decreases in insurance expense, the Advanced Metering Infrastructure (AMI) flow-through O&M, and BCUC levies.

Overall, the increase in 2027 O&M is approximately $5.784 million, net of capitalized overhead and RNG O&M transferred to the RNG Account.

1.4.4 Rate Base Growth (Section 7)

The 2027 rate base is forecast to increase by approximately $700.927 million compared to the 2026 Approved rate base, which results in an increase to the 2027 Forecast earned return and the 2027 deficiency of approximately $48.538 million. The increase is primarily due to capital additions related to a number of major projects, including the Interior Transmission System (ITS) Transmission Integrity Management Capabilities (TIMC) CPCN Project, the AMI CPCN Project, the Okanagan Capacity Mitigation Plan (OCMP) CPCN Project, and the Order in Council (OIC)-approved Tilbury 1A/1B Expansion Project as well as the Eagle Mountain-Woodfibre Gas Pipeline (EGP) Project. These additions are contributing $32.650 million of the $48.538 million rate base growth-related deficiency in 2027.

1.4.5 Depreciation (Section 7)

Depreciation expense in 2027 is forecast to increase the 2027 deficiency by $15.586 million. This increase is primarily due to the additions from the major projects noted in Section 1.4.4 above. The increase in depreciation expense is partially offset by approximately $0.175 million of contributions in aid of construction (CIAC), resulting in a net increase of $15.411 million in depreciation expense.

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

Amortization of deferral accounts in 2027 is forecast to decrease by $9.008 million, primarily resulting from a credit amortization of approximately $19.185 million from the Emissions Regulation deferral account for the monetization of carbon credits through Canada's Clean Fuel Regulations (CFR) in 2026, and a credit amortization of approximately $26.929 million from the non-rate base Flow-through deferral account, as discussed in Section 12.4.2.2. The credit amortization is partially offset by the amortization of the 2023-2025 Revenue Deficiency deferral account, which begins on January 1, 2027, as well as increased amortization from the DSM

[2] Increase in formula O&M of $4.372 million net of capitalized overhead.
[3] Increase in forecast O&M of $1.412 million net of capitalized overhead and RNG O&M transferred to the RNG Account.

deferral account due to increased DSM expenditures, the Existing Meter Cost Recovery deferral account and the Previously Retired Meter Cost Recovery deferral account (both of which are related to the AMI Project), and from the Net Salvage Provision/Cost deferral account which is a result of rate base growth.

1.4.7 Financing and Return on Equity (Section 8)

Financing impacts FEI's deficiency through changes in financing rates, as well as changes in the ratio of long-term debt versus short-term debt.

For 2027, FEI is forecasting a mid-year long-term debt issue of $600 million at a rate of 4.90 percent. This results in an average long-term rate of 4.74 percent embedded in the 2027 Forecast revenue requirement, which is 0.01 percent higher than the average long-term debt rate of 4.73 percent embedded in the 2026 Approved revenue requirement. FEI is forecasting a short-term debt rate of 3.72 percent, which is an increase from the 3.38 percent short-term debt rate embedded in the 2026 Approved revenue requirement. Overall, the 2027 deficiency is forecast to increase by $0.769 million due to the changes in financing rates (primarily due to the increase in the short-term debt rate) and by $0.019 million due to the changes in the financing ratio between long-term and short-term debt. Combining the impacts of the financing rate changes and ratio changes, the 2027 deficiency is forecast to increase by $0.788 million.

FEI utilizes the approved capital structure and return on equity (ROE) of 45.0 percent and 9.65 percent, respectively, to develop the 2027 revenue requirement.

1.4.8 Taxes (Section 9)

FEI's 2027 property taxes are forecast to increase by $11.813 million or 13.2 percent from 2026 Approved. The increase is primarily driven by higher assessed values.

There has been no change in the income tax rate of 27 percent from 2026. Income taxes are projected to decrease in 2027 by $34.104 million or 30.3 percent from 2026 Approved. The decrease in income tax in 2027 is primarily related to higher income tax deductions through Capital Cost Allowance (CCA). The drivers of the higher deductions are higher undepreciated capital cost (UCC) additions in 2027, the new legislation introduced by the Federal government for productivity-enhancing assets eligible for 100 percent CCA deduction, and the reinstatement of the Accelerated Investment Incentive rules enabling additional CCA deductions for qualifying expenditures made after January 1, 2025 and before 2034. The decrease from additional CCA deductions is partially offset by a higher rate base and higher depreciation of property, plant and equipment in 2027.

Overall, FEI is forecasting a decrease in tax expenses in 2027 of approximately $22.291 million.

1.5 SERVICE QUALITY INDICATORS (SECTION 13)

FEI reports on its 2025 and June 2026 year-to-date (YTD) SQI results in Section 13. Pursuant to the RSF Decision, eight of the SQIs have benchmarks and performance ranges set by a threshold level while 10 of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In 2025, for the eight SQIs with benchmarks, six performed at or better than the approved benchmarks, with two SQIs (Emergency Response Time and First Contact Resolution) below their respective benchmarks but above the thresholds. Regarding the informational indicators, the performance generally remains at a level consistent with prior years. In 2026 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2027 O&M and Growth capital amounts according to the RSF formula.

In the RSF Decision and Order G-69-25, the BCUC approved an I-Factor which includes a fixed labour weighting of 50 percent and fixed non-labour weighting of 50 percent for FEI during the RSF term and uses the actual CPI-BC and BC-AWE indices from the previous year.

The RSF Decision approved the use of a forecast of growth[4] to determine formula O&M and formula Growth capital. Further, the RSF Decision approved the elimination of a growth factor multiplier for formula O&M.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. FEI has used July 2024 through June 2026 inflation data for the 2027 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FEI determined the 2027 Inflation Factor based on prior years' BC-CPI and BC-AWE that are used to calculate the formula O&M discussed in Section 6 and the formula Growth capital discussed in Section 7. Section 2.3 below explains how FEI determined the average customer count that is used to calculate the formula O&M discussed in Section 6 and provides the gross customer additions forecast that is used to calculate the formula Growth capital discussed in Section 7.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the RSF Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and using a fixed 50 percent weighting for each index. FEI uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2026 for AWE-BC has been used as a placeholder, as results for May and June 2026 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in the compliance filing to the BCUC's decision on this Application.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the fixed labour weighting of 50 percent, the calculation of the 2027 I-Factor is (2.134 percent x 50 percent) + (2.767 percent x 50 percent) = 2.451 percent.

[4] Forecast of average customers for formula O&M and a forecast of gross customer additions for formula Growth capital, both including a true-up to actuals in the following years.

Table 2-1: I-Factor Calculation

		Table: 18-10-0004-01	*Table: 14-10-0223-01*	12 Mth Average				Last Completed Year			
Line No.	Date	BC CPI index	BC AWE $	CPI index	AWE $	CPI %	AWE %	Non Labour %	Labour %	I-Factor %	RSF Year
1	Jul-2024	156.4	1,280.92								
2	Aug-2024	156.2	1,284.97								
3	Sep-2024	155.8	1,285.71								
4	Oct-2024	156.2	1,289.28								
5	Nov-2024	156.3	1,290.96								
6	Dec-2024	156.1	1,292.51								
7	Jan-2025	156.0	1,298.71								
8	Feb-2025	157.6	1,299.76								
9	Mar-2025	157.8	1,302.42								
10	Apr-2025	157.8	1,308.50								
11	May-2025	159.0	1,294.59								
12	Jun-2025	158.8	1,302.31	157.0	1,294.22	2.397%	4.010%	50%	50%	3.204%	2026
13	Jul-2025	159.1	1,299.03								
14	Aug-2025	159.0	1,302.02								
15	Sep-2025	158.8	1,309.68								
16	Oct-2025	159.4	1,310.70								
17	Nov-2025	159.5	1,320.73								
18	Dec-2025	158.7	1,315.46								
19	Jan-2026	159.1	1,331.01								
20	Feb-2026	160.3	1,349.12								
21	Mar-2026	161.7	1,349.57								
22	Apr-2026	161.7	1,357.68								
23	May-2026	163.6	1,357.68								
24	Jun-2026	163.3	1,357.68	160.4	1,330.03	2.134%	2.767%	50%	50%	2.451%	2027

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the BCUC approved the use of a forecast of average customers, without discount, to determine formula O&M, and a forecast of gross customer additions (GCA) to determine formula Growth capital.

Table 2-2 below provides the 12-month customer counts and the average customer counts for 2026 Projected and 2027 Forecast. The 2027 Forecast average customer count (shown on Line 22 of Table 2-2 below) is 1,113,600, which is used to determine FEI's 2027 Formula O&M. Table 2-2 below also shows the 2025 true-up of the average customer count of negative 1,437, which is reflected in the 2027 Formula O&M, as discussed in Section 6.

Table 2-2: Calculation of 2027 Average Customer (AC) Growth Factor

Line No.	Date	2026 Projected	2027 Forecast	Reference
1	Prior Year Ending Customer Count	1,104,549	1,110,770	Appendix A2 Table A2-1 FEI Customers
2				
3	Projected/Forecast Monthly Ending Customer Count			
4	January	1,105,986	1,112,111	
5	February	1,106,749	1,112,827	
6	March	1,106,882	1,112,938	
7	April	1,107,008	1,113,047	
8	May	1,107,345	1,113,376	
9	June	1,107,365	1,113,394	
10	July	1,106,924	1,112,970	
11	August	1,106,769	1,112,819	
12	September	1,107,049	1,113,084	
13	October	1,108,406	1,114,375	
14	November	1,109,721	1,115,627	
15	December	1,110,770	1,116,626	
16	Total Projected/Forecast Additions for the Year	6,221	5,856	Line 15 - Line 1; Appendix A2 Table A2-1
17				
18	Actual/Projected Prior Year Average Customers	1,101,521	1,107,581	2025: Sch 3, Line 13; 2026 & 2027: Prior Year, Line 19
19	Average Customers for the Year	1,107,581	1,113,600	Average of Line 4 to Line 15
20	Change in Average Customers	6,061	6,018	Line 19 - Line 18
21				
22	**Average Customer Forecast for Rate Setting**	**1,107,581**	**1,113,600**	Line 19
23				
24	2025 Approved Average Customers		1,102,958	G-287-25 (Schedule 19)
25	2025 Actual Average Customers		1,101,521	2025 Annual Report
26	**2025 True Up**		**(1,437)**	(Line 25 - Line 24)

The forecast for FEI's gross customer additions which is used to determine the formula Growth capital is provided in the table below. As explained in Section 7.2.1, the calculation of formula Growth capital includes the true-up of gross customer additions from two years prior (i.e., 2025 for the 2027 revenue requirement).

Table 2-3: Forecast Gross Customer Additions (GCA)

Line	Gross Customer Additions		Reference
1	2025 Approved	10,000	
2	2025 Actual	11,364	
3	2025 True-up	1,364	Section 7, Table 7-2, line 14
4			
5	2026 Approved	8,000	
6	2026 Projected	9,300	
7	2027 Forecast	8,800	Schedule 4, line 5

Gross customer additions is a forecast of new customers attaching to the gas distribution system. It comprises both new construction activity and conversions from other fuels to natural gas. In developing the 2027 GCA forecast, FEI has reviewed information contained in FEI's customer relationship management system (leads, connection requests, timing of connection requests, etc.) along with interactions with builders, developers, and contractors. FEI also uses market information such as building permits, forecast housing starts and completions, and knowledge of any policy or building code changes that may affect specific municipalities.

FEI is forecasting gross customer additions of 8,800 for 2027, which is higher than the 2026 Approved amount of 8,000 but lower than FEI's 2025 Actual and 2026 Projected GCAs of 11,364 and 9,300, respectively.

While the 2025 Actual and 2026 Projected GCAs are higher than the approved amounts, the overall trend is declining, and FEI's 2027 Forecast GCA is in line with this trajectory. FEI expects the growth in new customer attachments will continue to soften compared to previous years given the current and expected market conditions for new construction and due to the continued impact of building codes, government policies, and strong incentives supporting home electrification. In addition, conversion activity is expected to remain below historical levels due to higher financing costs and competing electrification incentives.

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M and formula Growth capital for 2027 is provided in Table 2-4 below, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.55 percent, and the forecasts of average customers and gross customer additions determined in Section 2.3.

Table 2-4: Summary of Formula Drivers

Line	Particulars	2027	Reference
1	CPI	2.134%	Table 2-1, Line 24
2	AWE	2.767%	Table 2-1, Line 24
3			
4	Non Labour	50%	Table 2-1, Line 24
5	Labour	50%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	2.451%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.550%	Order G-69-25
10			
11	Net Inflation Factor	1.901%	Line 7 + Line 9
12			
13	Average Customers for 2027 Formula O&M purposes	1,113,600	Table 2-2, Line 22
14			
15	Gross Customer Additions for 2027 Formula Growth Capital purposes	8,800	Table 2-3, Line 7

In summary, the Net Inflation Factor for 2027 is 1.901 percent. FEI's formula O&M for 2027 is determined using average customers of 1,113,600, and the formula Growth capital is determined using gross customer additions of 8,800.

3. DEMAND FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FEI's forecast of gas sales and transportation volumes. FEI's demand forecasts have been developed in accordance with the methods approved by the BCUC in the RSF Decision[5]. As determined in the RSF Decision, the merits of the approved demand forecasting methods are outside the scope of the Annual Reviews during the RSF term.

For 2027, FEI is forecasting normalized demand (2027F) of approximately 218.2 PJ, which is a reduction of approximately 4.0 PJ (or 1.8 percent) compared to the 2026 Approved level. The forecast decrease is primarily from residential, large commercial, and large volume transportation customers, but is partially offset by significant growth in LNG demand under RS 46, which is forecast to increase by approximately 2.4 PJ (or 69.5 percent) from the 2026 Approved level.

At the 2026 Approved rates for each customer class, FEI's 2027 Forecast revenue and delivery margin are $1,861 million and $1,381 million, respectively.

The following sections set out the results of the demand forecasts. In the figures provided in the demand forecast sections, the following time periods are shown:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year. For this Annual Review, the latest calendar year for which full actual data exists is the 2025 calendar year.
- **Seed Year:** The year prior to the first forecast year, which is 2026 for this Application (2026S). The Seed Year is forecast based on the latest years of actual data available (through 2025).
- **Forecast Year:** This is the year or years for which the forecast is being developed. For this Application, the forecast year is 2027 (2027F).

Please refer to Appendix A2 of the Application for the historical actual and forecast demand over the past 10 years.

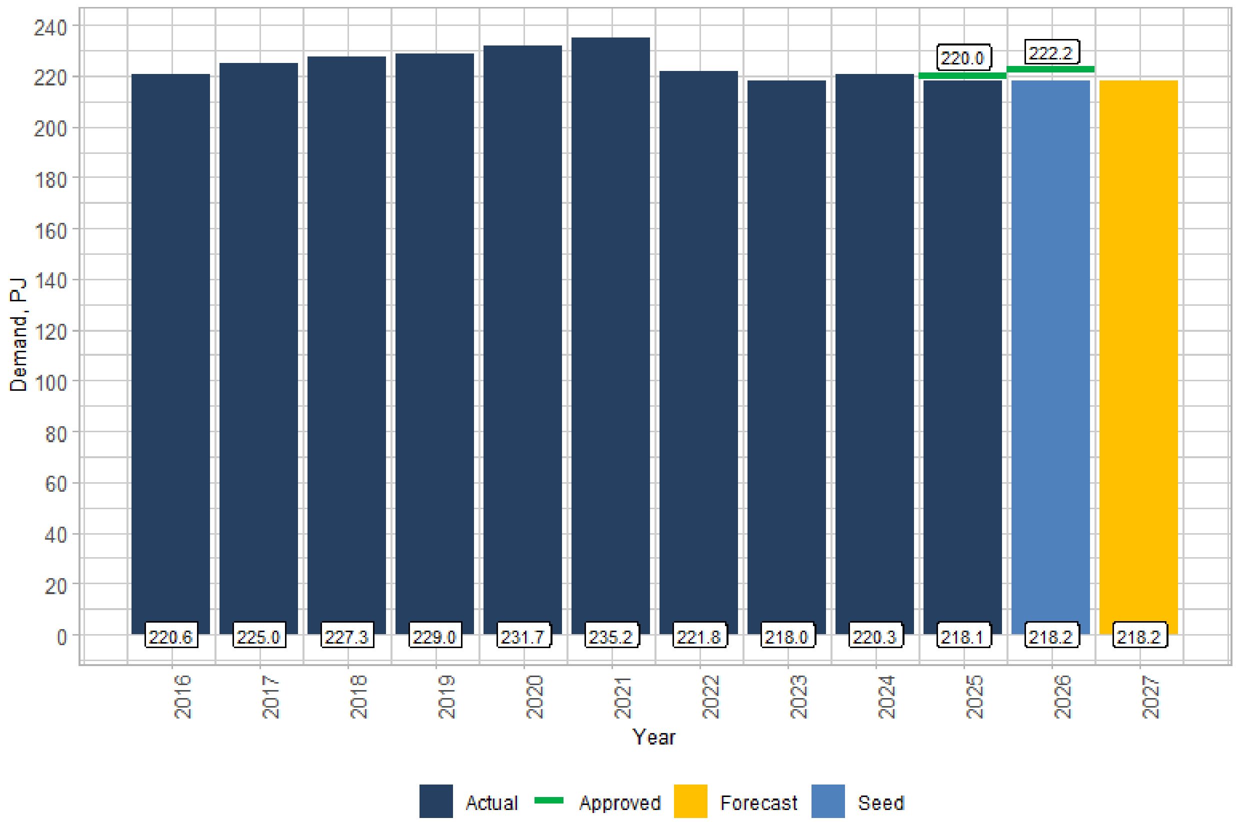
3.2 *DEMAND FORECAST*

FEI's total energy demand consists of the weather normalized residential and commercial demand, and the customer-specific industrial, NGT and non-NGT LNG demand.

As shown in Figure 3-1 below, the demand forecast variance in 2025 was approximately 1.9 PJ or 0.9 percent. For 2027, FEI is forecasting a total load of 218.2 PJ, which is a decrease of approximately 4.0 PJ (or 1.8 percent) from 2026 Approved.

[5] RSF Decision and Order G-69-25, pp. 73-74.

Figure 3-1: Total Energy Demand



The residential, commercial, industrial, and NGT and non-NGT (LNG) demand forecasts are provided separately in the following subsections.

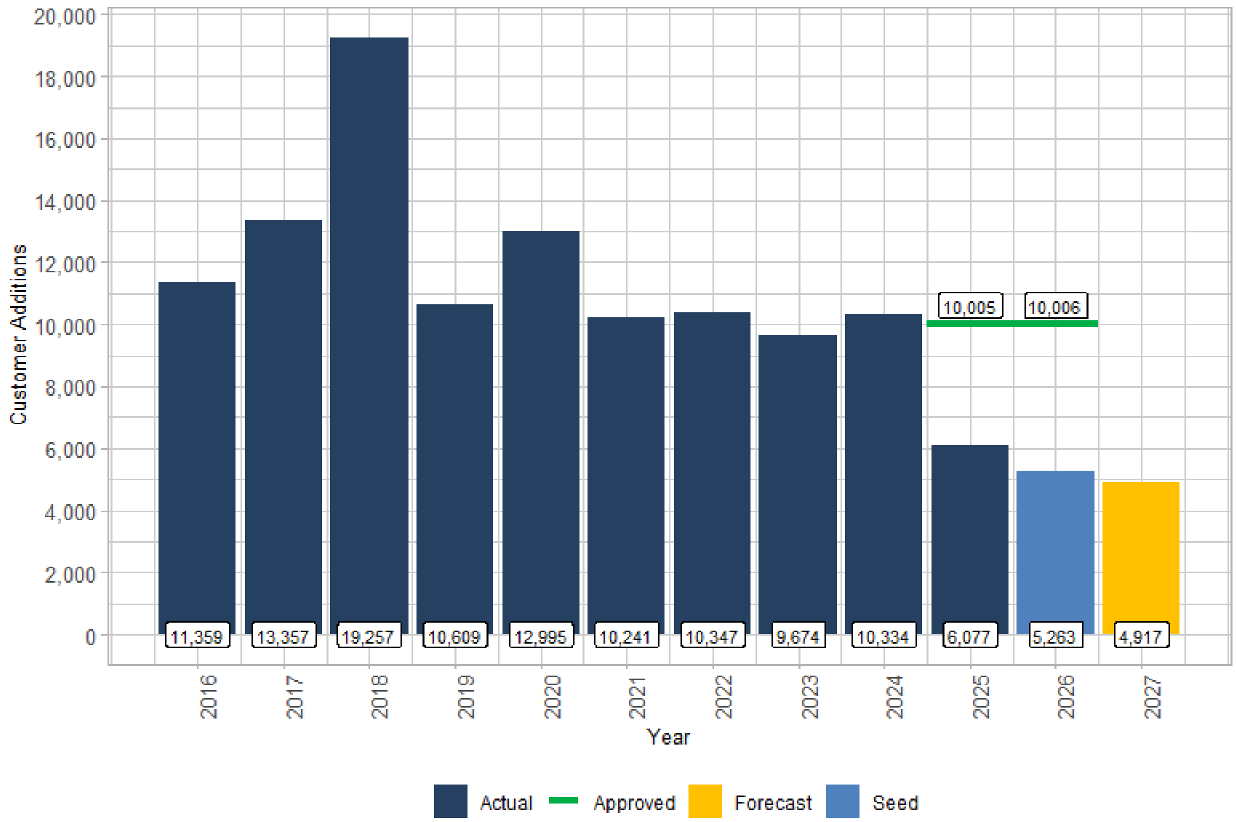
3.2.1 Residential

3.2.1.1 Residential Net Customer Additions

Consistent with the forecasting methodology approved in the RSF Decision, the residential net customer additions are forecast based on applying the 2026 and 2027 growth rates of single-family dwellings and multi-family dwellings from the Conference Board of Canada (CBOC) housing starts forecast, which was issued on March 27, 2026, to the 2025 actual net additions. The CBOC data is provided in Appendix A1 and is forecasting a general slow down of new housing starts, with the growth rates for single-family dwellings declining by 13.5 percent and 6.8 percent for 2026 and 2027, respectively, and the growth rates for multi-family dwellings declining by 13.3 percent and 6.4 percent for 2026 and 2027, respectively.

Due to the declining growth rates in the housing starts forecasts, combined with the low 2025 Actual residential net customer additions, FEI is forecasting a decline in residential net customer additions in 2027, as shown in Figure 3-2 below.

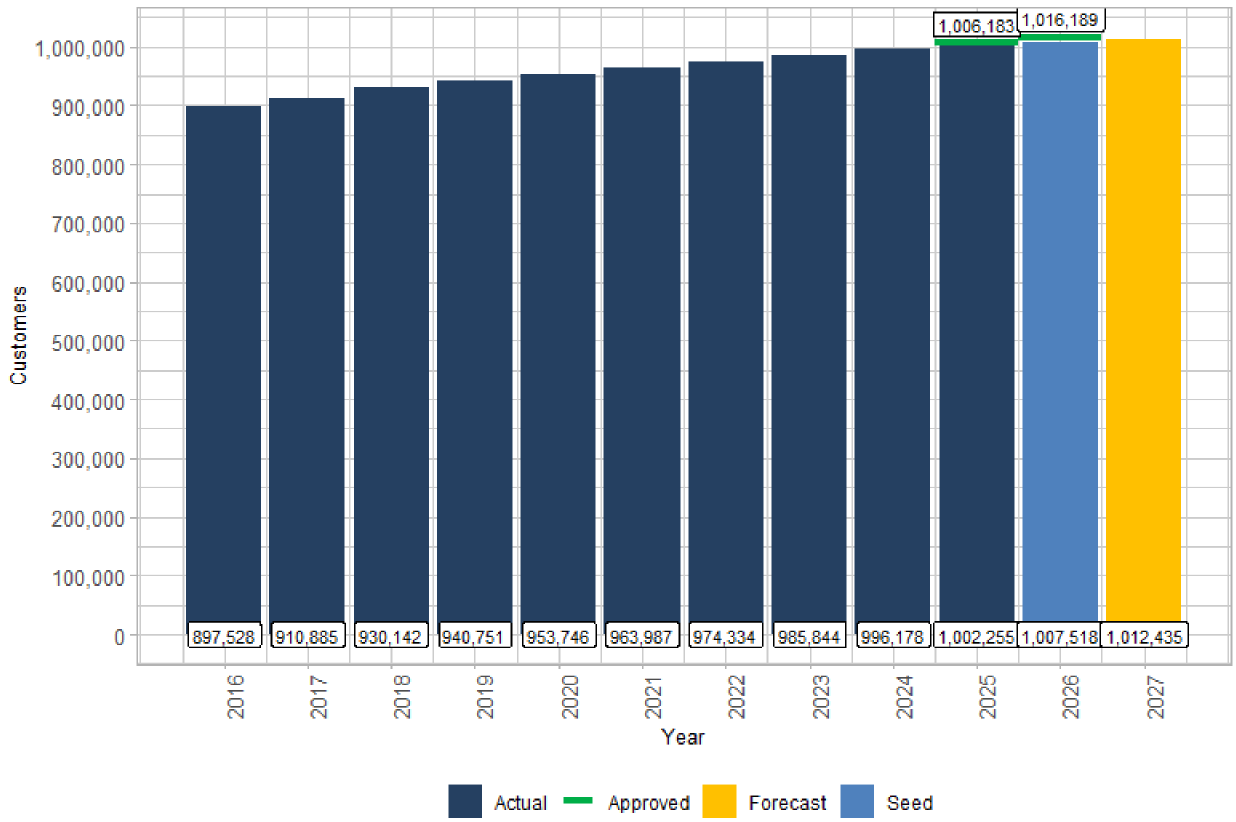
Figure 3-2: Residential Net Customer Additions



As shown in Figure 3-2 above, the 2025 Actual residential net customer additions were 3,928 lower than forecast. A variety of factors likely contributed to this result, including the timing between move-ins and move-outs (e.g., the time lag between a customer moving out and a new customer moving in), and the recent trend of declining new customer attachments driven by the slow-down in the housing market.

Figure 3-3 below provides the actual total net residential customers for 2016 to 2025 and the forecasts for 2026S and 2027F. Based on the residential net customer additions forecast discussed above, FEI is forecasting the 2027 year-end net residential customer count to be approximately 1.012 million, which is a small increase of 4,917 (or 0.5 percent) from 2026S but is a small decrease of 3,754 (0.4 percent) when compared to 2026 Approved.

Figure 3-3: Net Residential Customers

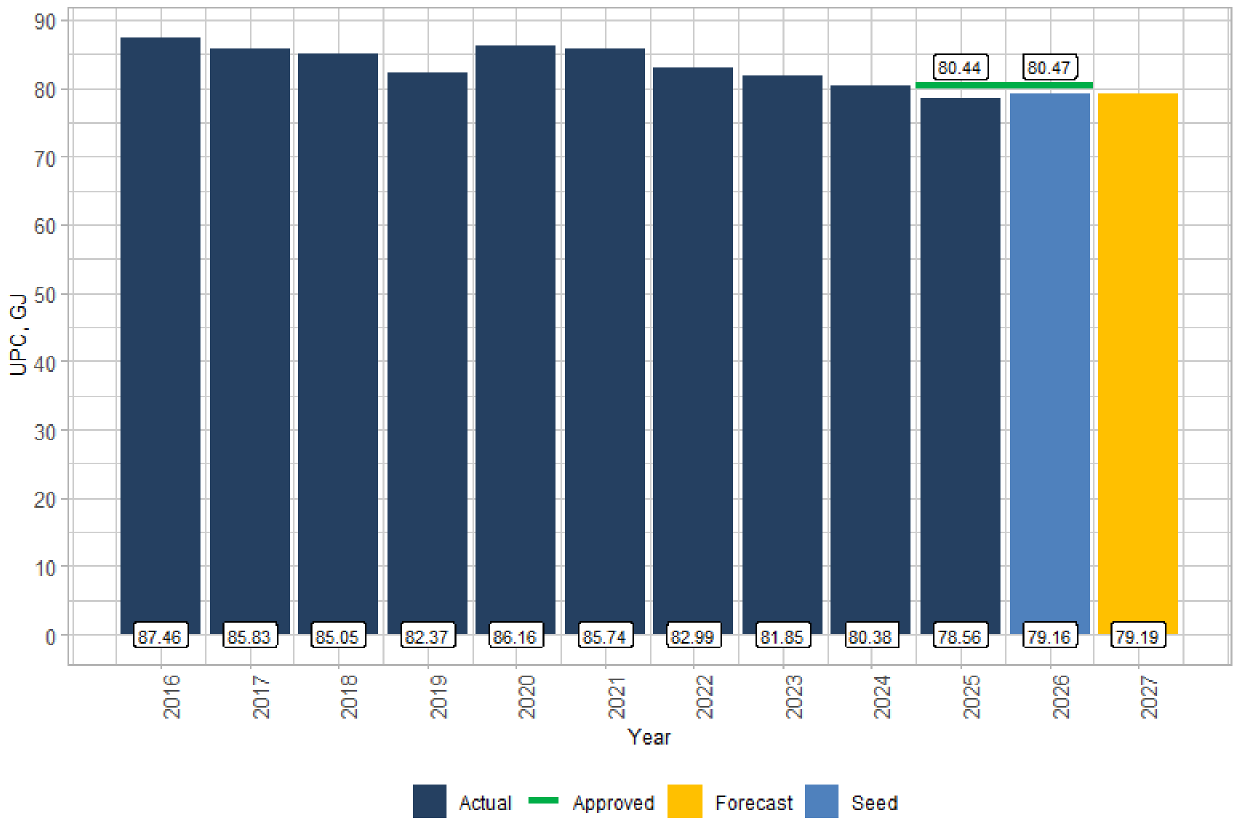


Given the total number of residential customers of approximately 1 million, a variance of 3,928 net residential customers in 2025 is equivalent to only approximately 0.4 percent of FEI's total residential customers. As such, the variance in 2025 net residential customer additions has a minimal impact on the overall accuracy of the residential customer forecast (i.e., a percent error of 0.4 percent for 2025 as shown in Section 3.1 of Appendix A2).

3.2.1.2 Residential UPC

As shown in Figure 3-4 below, the residential UPC is forecast to increase by approximately 0.03 GJ in 2027 compared to 2026S.

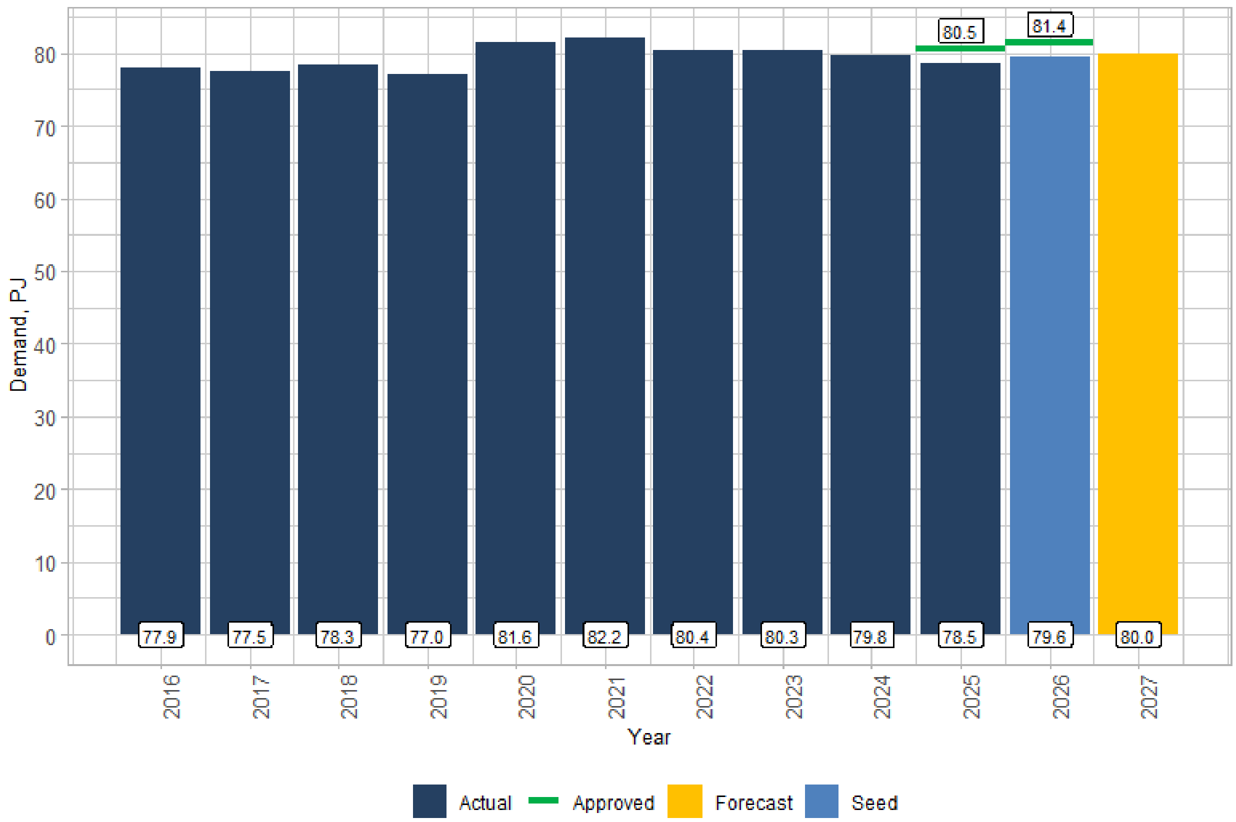
Figure 3-4: Residential UPC



3.2.1.3 Residential Demand

Taking into account the customer additions and UPC forecasts described above, and as shown in Figure 3-5 below, residential demand is forecast to increase by 0.4 PJ in 2027 compared to 2026S.

Figure 3-5: Normalized Residential Demand



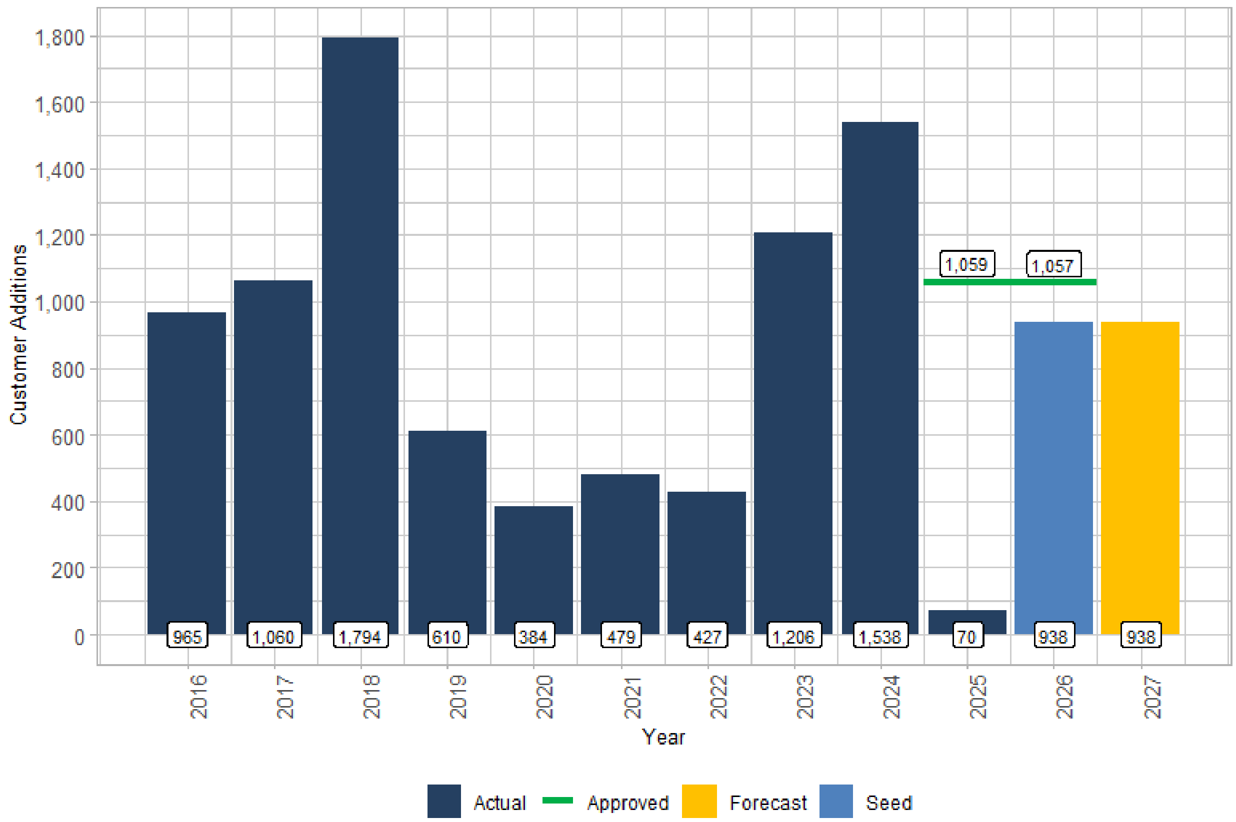
3.2.2 Commercial

3.2.2.1 Commercial Net Customer Additions

Consistent with the forecasting methodology approved in the RSF Decision, the commercial net customer additions are forecast based on the most recent three-year average of actual net commercial customer additions (by region and by rate schedule).

As shown in Figure 3-6 below, the 2026S and 2027F commercial net customer additions are 938.

Figure 3-6: Commercial Net Customer Additions



As shown in Figure 3-6 above, the 2025 Actual commercial net customer additions were 70 (compared to a 2025 Approved amount of 1,059). While a variety of factors likely contributed to this result, the relatively larger reduction in 2025 compared to previous years appears to coincide with the general economic downturn in BC and Canada, with reports indicating that BC small businesses have faced significant sales declines[6] and that more businesses have been closing than opening in Canada.[7]

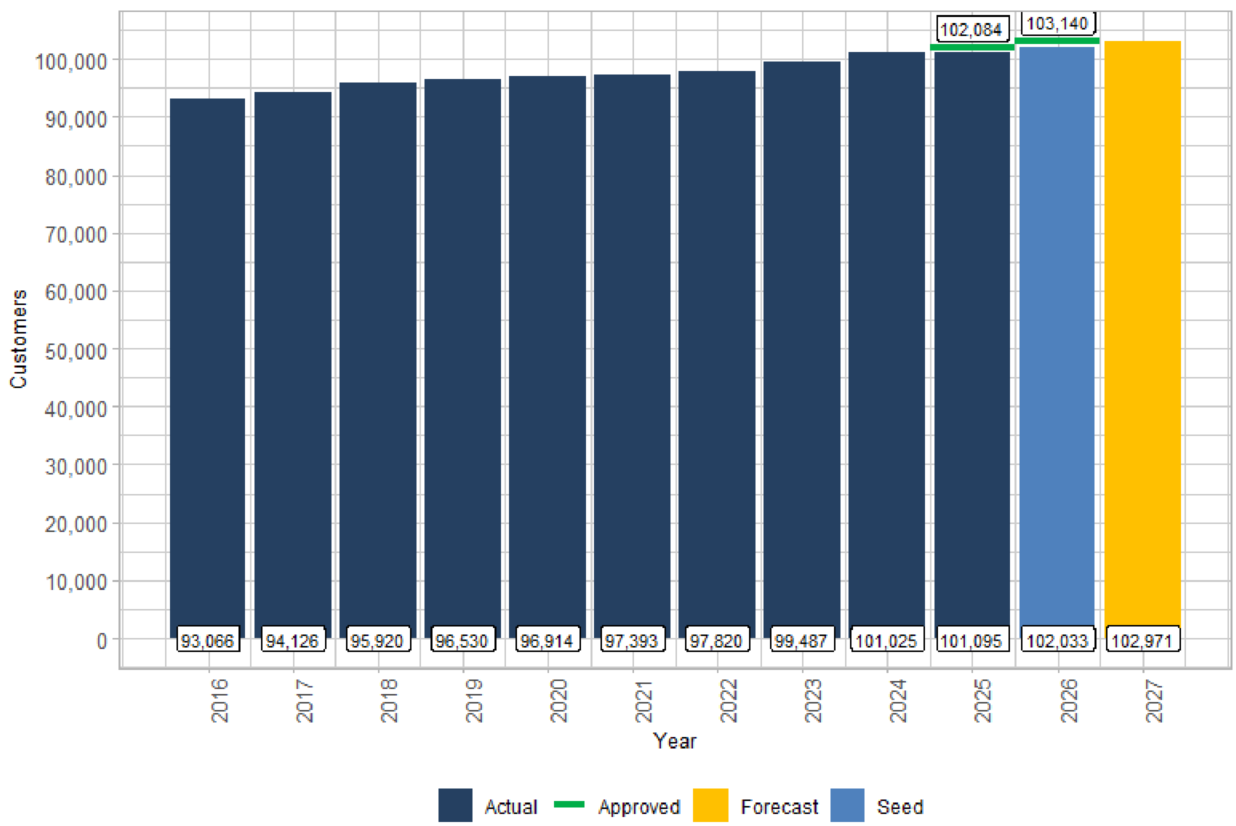
Figure 3-7 below provides the actual total net commercial customers for 2016 to 2025 and the forecasts for 2026S and 2027F. Based on the 2025 year-end actual customer counts and the net commercial customer additions forecast discussed above, FEI is forecasting the 2027 year-end commercial customer count (comprised of RS 2 Small Commercial, RS 3 Large Commercial, and RS 23 Large Commercial Transportation) to be 102,971, which is an increase of 938 (or 0.9

[6] BC small businesses suffered worst sales decline in Canada, report states, March 4, 2026. (https://globalnews.ca/news/11717108/bc-small-businesses-worst-sales-decline-canada-report/).

[7] https://www.cfib-fcei.ca/en/media/more-businesses-have-been-closing-than-opening-in-canada.-its-time-to-admit-it-were-in-an-entrepreneurial-drought and https://www.biv.com/news/commentary/opinion-why-bc-may-already-be-in-a-recession-12115475.

percent) from 2026S but is a small decrease of 169 (or 0.2 percent) when compared to 2026 Approved.

Figure 3-7: Net Commercial Customers



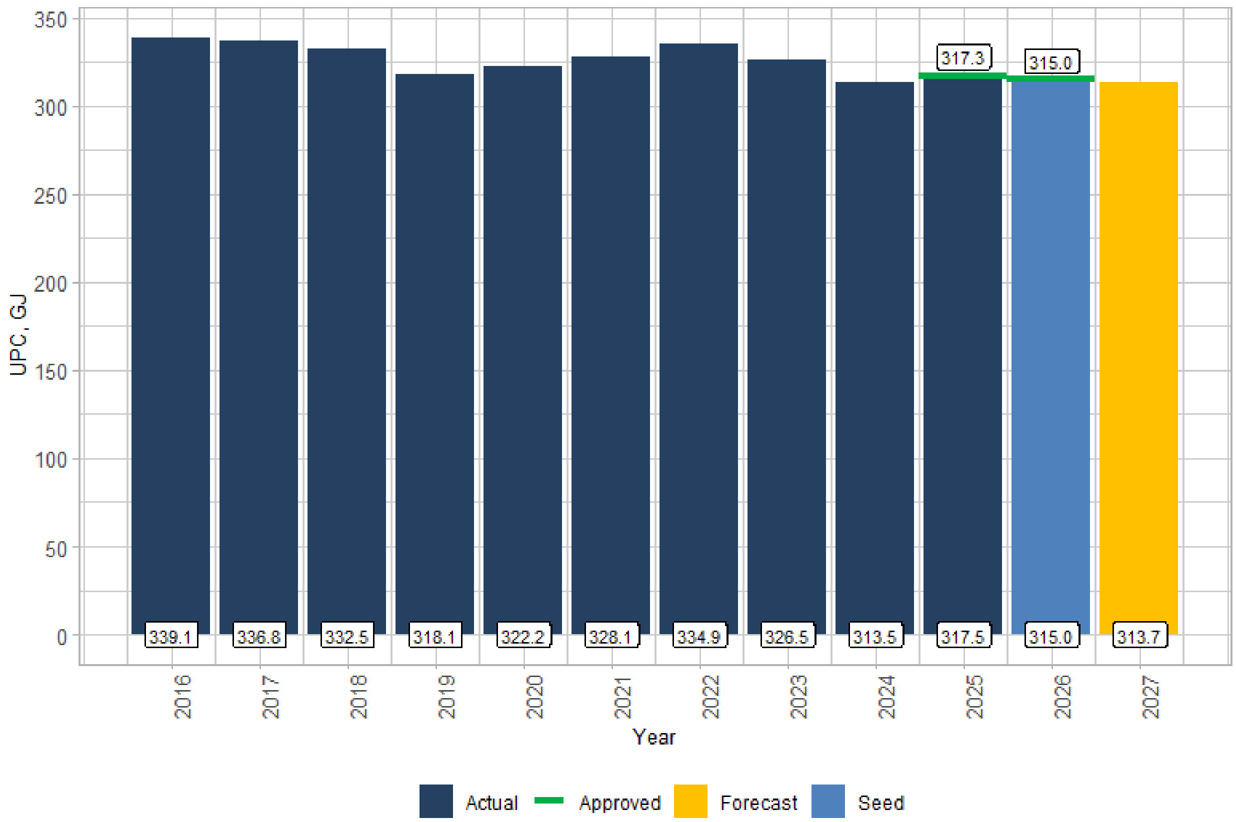
At 2025 year-end, there were a total of 101,095 commercial customers, as shown in Figure 3-7 above. The variance between 2025 Approved and 2025 Actual commercial customers of 989 is equivalent to less than 1.0 percent of FEI's total commercial customer count in 2025. As such, the variance in 2025 net commercial customer additions has a minimal impact on the overall accuracy of the commercial customer forecast (i.e., a percent error of approximately 1.0 percent for 2025 as shown in Section 3.1 of Appendix A2[8]).

3.2.2.2 Commercial UPC

As shown in Figure 3-8 below, the RS 2 UPC is forecast to decrease by 1.3 GJ in 2027 compared to 2026S.

[8] Including RS 2, RS 3, and RS 23.

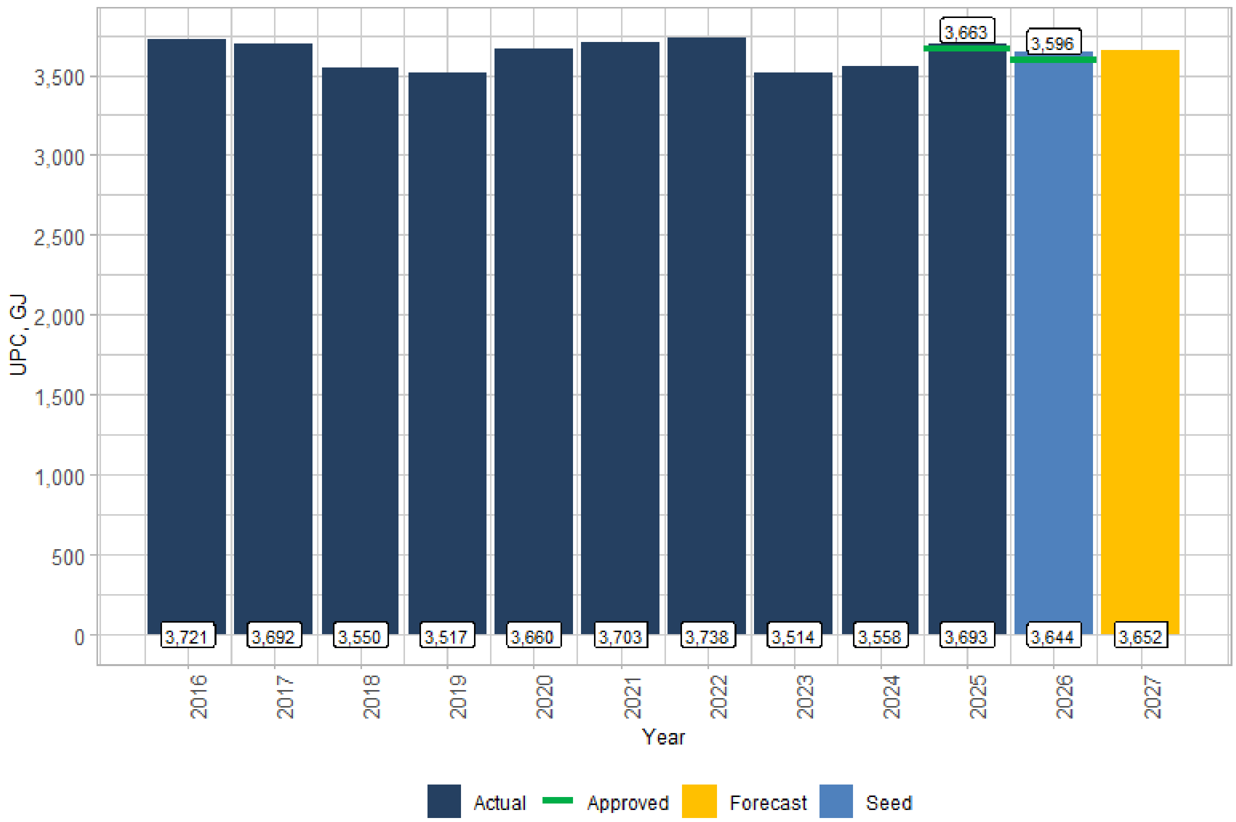
1 **Figure 3-8: Rate Schedule 2 UPC**



2

3 As shown in Figure 3-9 below, the RS 3 UPC is forecast to increase by approximately 8 GJ in
4 2027 compared to 2026S.

1 **Figure 3-9: Rate Schedule 3 UPC[9]**

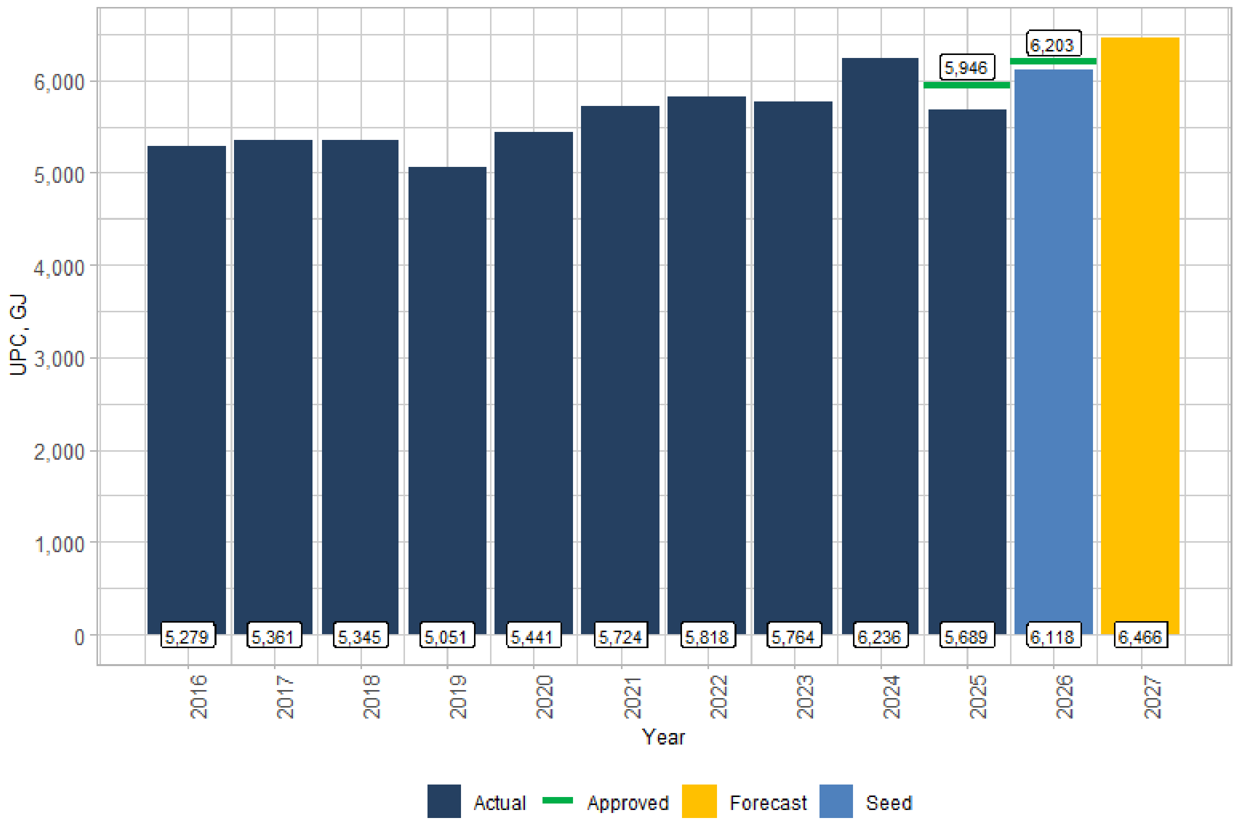


2

3 As shown in Figure 3-10 below, the RS 23 UPC is forecast to increase by approximately 348 GJ
4 in 2027 compared to 2026S.

9 Excludes NGT customers under RS 3.

1 **Figure 3-10: Rate Schedule 23 UPC[10]**



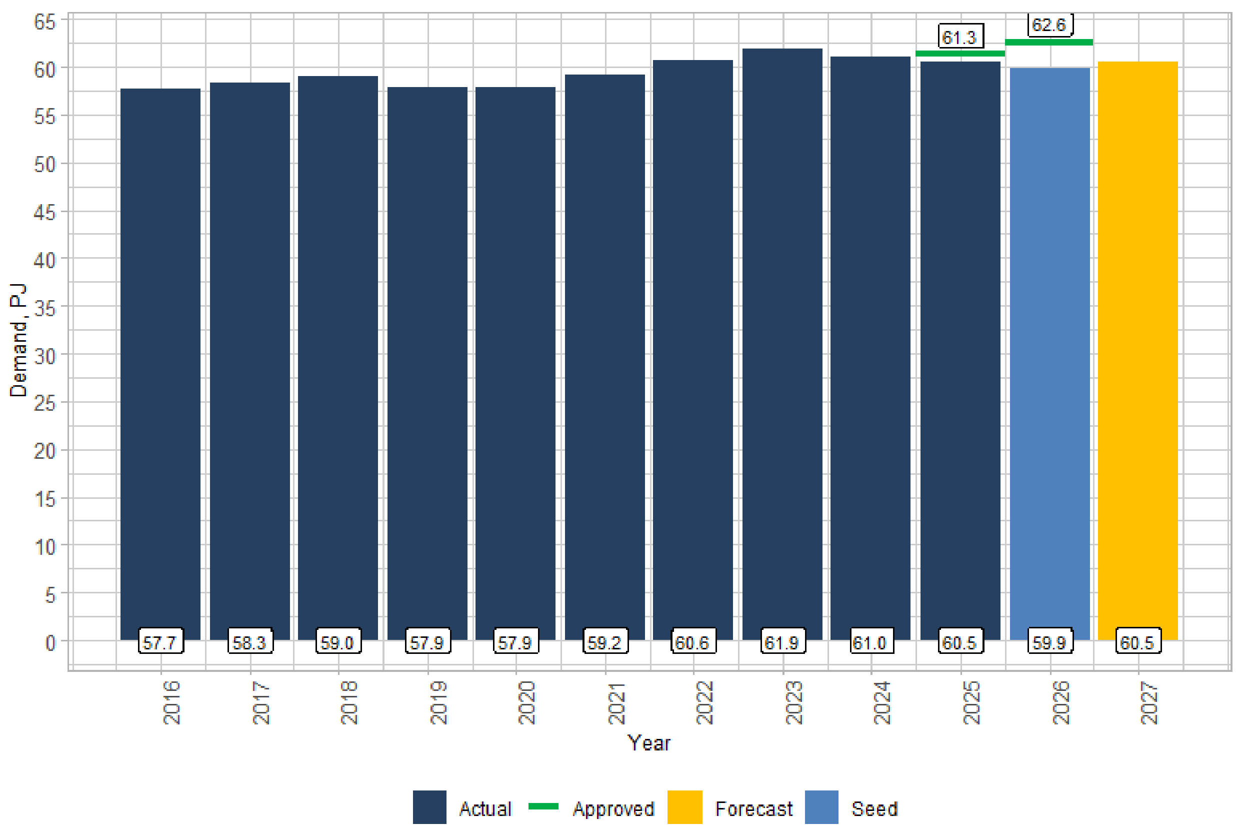
2

3 ***3.2.2.3 Commercial Demand***

4 Taking into account the commercial customer additions and UPC forecasts described above, and
5 as shown in Figure 3-11 below, commercial demand is forecast to increase by 0.6 PJ in 2027
6 compared to 2026S.

[10] Excludes NGT customers under RS 23.

Figure 3-11: Commercial Demand[11]



3.2.3 Industrial Demand

Consistent with the forecasting methodology approved in the RSF Decision, the industrial demand is forecast based on a survey completed by individual industrial customers.

For the 2027 Forecast, customers responded to the survey from May through July of 2026. The survey was launched as close as possible to the filing date to mitigate potential variances in the forecast.

As shown in Table 3-1 below, the response rate achieved in 2026 was 36 percent of industrial customers, representing approximately 86 percent of industrial volumes. There was no reply from 63.8 percent of industrial customers who received the survey after three reminder notifications; this group represents approximately 13.9 percent of the industrial demand. Surveys could not be delivered to 0.2 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 0.1 percent of the total industrial demand.

[11] Excludes NGT customers under RS 3 and 23.

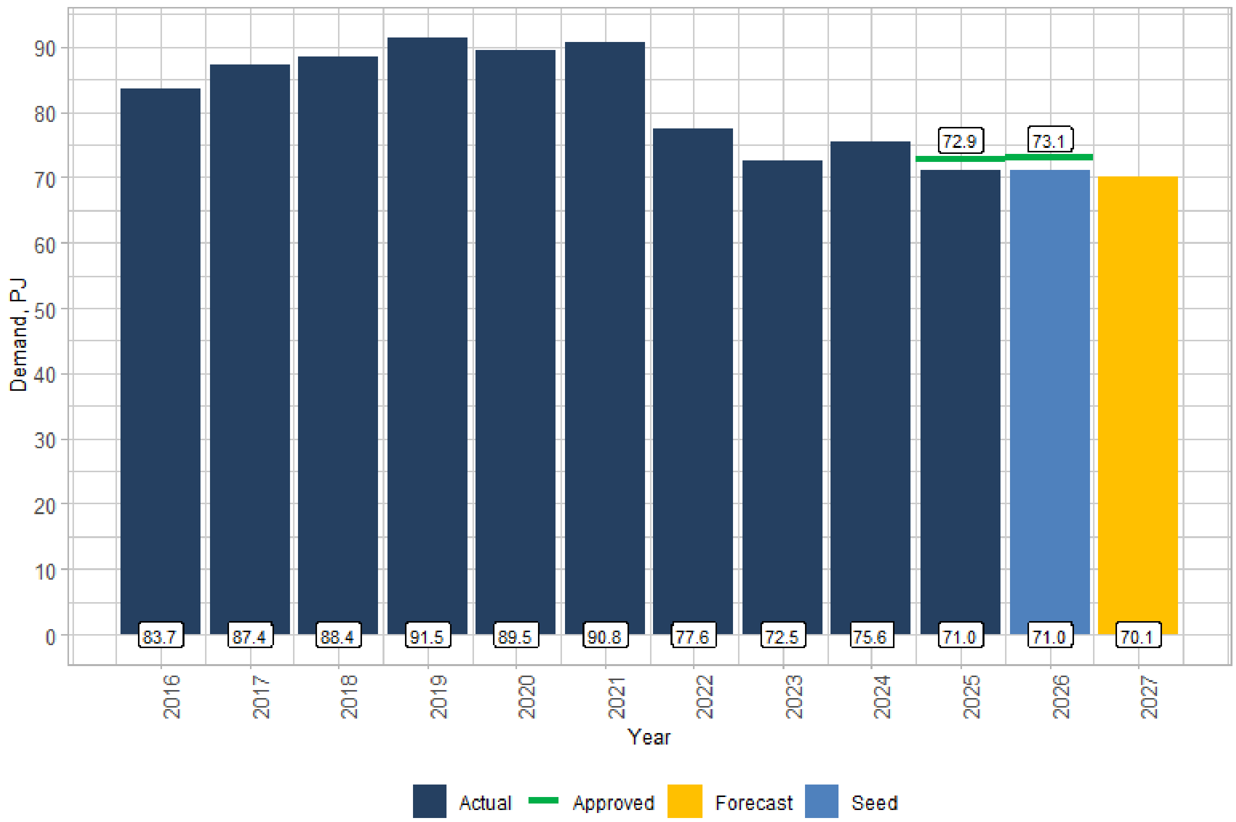
Table 3-1: Industrial Survey Response Rates

Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	36.0%	86.0%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	63.8%	13.9%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	0.2%	0.1%
Total		100.0%	100.0%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 14 percent of the total industrial demand) was set to equal 2025 Actual consumption.

As shown in Figure 3-12 below, the demand from industrial rate schedules is forecast to decrease by 0.9 PJ in 2027 compared to 2026S. Figure 3-12 provides the industrial demand for 2016 through 2027.

Figure 3-12: Industrial Demand[12]



3.2.4 NGT and LNG Demand

This section summarizes the compressed natural gas (CNG) and LNG demand forecasts from FEI's NGT services as well as non-NGT related demand for LNG supplied under RS 46. Table 3-2 below provides the 2026 Approved, 2026 Projected, and 2027 Forecast of total NGT (CNG and LNG) and non-NGT LNG demand. The forecast of the total NGT and non-NGT LNG demand includes only actual volumes taken by customers under spot purchase agreements up to May 31, 2026, to align with the forecasting approach discussed in the RSF Application.

[12] Excludes NGT and non-NGT LNG customers under RS 5, 25, and 46.

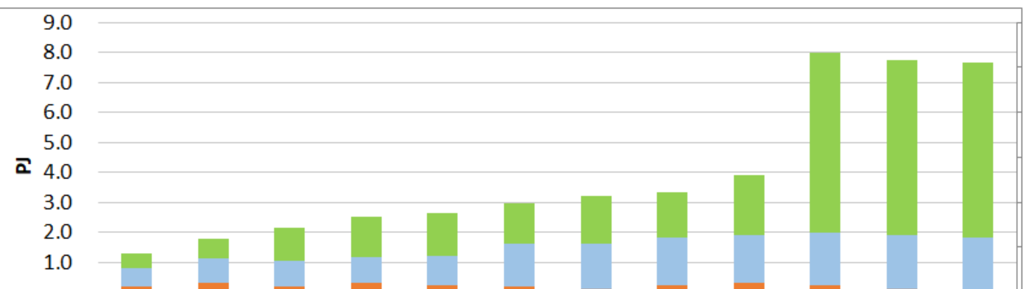
Table 3-2: FEI Total Natural Gas Demand for NGT and non-NGT LNG (TJ)

	2026 Approved	2026 Projected	2027 Forecast
CNG	1,730.5	1,771.0	1,806.4
LNG	3,321.4	5,833.2	5,862.9
Total NGT Demand (TJ)	**5,051.9**	**7,604.2**	**7,669.3**
Non-NGT LNG	138.0	118.7	-
Total NGT and Non-NGT Demand (TJ)	**5,189.9**	**7,722.9**	**7,669.3**

The 2026 Projected demand of 7.7 PJ is approximately 2.5 PJ higher than 2026 Approved, which is equivalent to an increase of 48.8 percent. The increase is primarily related to the significant growth in LNG demand for marine bunkering since 2025 (as shown in Figure 3-13 below).

For 2027, consistent with the forecasting approach discussed in the RSF Application, FEI is forecasting a similar level of LNG demand for NGT, a small increase in CNG demand, and reduced demand for non-NGT LNG. The small increase in CNG demand for 2027 is primarily due to increasing demand by customers taking service at the existing CNG stations owned by FEI. As shown in Figure 3-13 below, the CNG demand has shown a steady and gradual increase since 2016. For non-NGT LNG demand, consistent with the forecasting approach discussed in the RSF Application, the forecast is based only on signed contract demand associated with ISO containers. As the current ISO exporting contracts expire in 2026, FEI is forecasting no demand for 2027.

Figure 3-13: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG (PJ)[13]



	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023A	2024A	2025A	2026P	2027F
RS 46 - LNG (NGT)	0.5	0.7	1.1	1.3	1.4	1.3	1.6	1.5	2.0	6.0	5.8	5.9
RS 3/5/23/25/6P - CNG (NGT)	0.6	0.8	0.9	0.9	1.0	1.4	1.5	1.6	1.6	1.7	1.8	1.8
RS 46 - LNG (Non-NGT)	0.2	0.3	0.2	0.3	0.2	0.2	0.1	0.2	0.3	0.2	0.1	-
Total CNG & LNG	1.3	1.8	2.1	2.5	2.7	3.0	3.2	3.3	3.9	8.0	7.7	7.7

13 Forecast includes all NGT-related CNG and LNG demand and Other LNG demand, inclusive of contract and excess demand flowing through stations and third-party station CNG/LNG volumes.

3.3 *REVENUE AND MARGIN FORECAST*

The forecasts of revenues and delivery margins have been developed by considering the total forecast of energy demand in GJ at the approved delivery, commodity, and storage and transport rates.

3.3.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEI has developed its forecast of revenues by multiplying the energy forecast by the approved rates for each customer class.

Table 3-3 below summarizes the 2026 Approved, 2026 Projected, and 2027 Forecast revenue, by customer segment, at currently approved 2026 rates.

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

Revenue ($ millions)	2026 Approved	2026 Projected	2027 Forecast
Residential[1]	$ 1,101.141	$ 1,059.418	$ 1,046.814
Commercial[2]	601.780	563.764	555.459
Industrial[3]	249.057	268.146	258.911
Total	**$ 1,951.978**	**$ 1,891.328**	**$ 1,861.184**

<u>Notes to table:</u>

1 Rate Schedule 1.

2 Rate Schedules 2, 3, 23.

3 Rate Schedules 4, 5, 6, 6P, 7, 22, 25, 27, 46, Byron Creek, and Joint Venture.

3.3.2 Delivery Margin

Delivery margins are calculated by subtracting the cost of gas (discussed in Section 4) from the total revenues set out in Table 3-3 above.

Table 3-4 below summarizes the 2026 Approved, 2026 Projected, and 2027 Forecast margin, by customer segment, at currently approved 2026 delivery rates.

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

Delivery Margin ($ millions)	2026 Approved	2026 Projected	2027 Forecast
Residential[1]	$ 822.807	$ 806.918	$ 811.191
Commercial[2]	400.404	385.534	388.990
Industrial[3]	164.508	183.934	181.132
Total	**$ 1,387.719**	**$ 1,376.386**	**$ 1,381.313**

Notes to table:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

[3] Rate Schedules 4, 5, 6, 6P, 7, 22, 25, 27, 46, Byron Creek, and Joint Venture.

Variances between the delivery margin forecast in this section and the actual delivery margin are captured in either the RSAM deferral account if they relate to use rate variances for residential and commercial customers, or the Flow-through deferral account for all other variances.

3.4 *SUMMARY*

FEI's forecast of demand for natural gas is based upon methods approved in the RSF Decision. FEI is forecasting a small decrease in consumption in 2027 of 4.0 PJ or 1.8 percent compared to the 2026 Approved level. Based on the 2026 Approved rates for each customer class, FEI's 2027 Forecast gross margin is approximately $1,381 million, which is a decrease of approximately $6.4 million from the 2026 Approved amount.

4. COST OF GAS

The cost of gas includes the cost of the gas commodity, the cost of midstream resources (storage and transportation), and the Core Market Administration Expense (CMAE) costs associated with providing the gas supply function. FEI is not requesting approval of forecast gas costs within this Application. Instead, any rate changes related to the flow through of gas costs and the CMAE[14] are dealt with in separate applications to the BCUC. Any variations between forecast and actual gas costs will continue to be returned to, or recovered from, customers through the existing deferral account mechanisms.

While FEI is not requesting approval of forecast gas costs in this Application, the forecast cost of gas is required in the determination of a number of revenue requirement line items that form part of the forecasts included in this Application. The total cost of gas for the purposes of this Application has been determined by multiplying forecast sales volumes using the demand forecasts described in Section 3 by the current commodity gas recovery charge and the Storage and Transport (S&T) charge for each rate schedule.

Table 4-1 below summarizes, by customer segment, the 2026 Approved cost of gas that was forecast as part of the Annual Review for 2025 and 2026 Delivery Rates, the 2026 Projected, and 2027 Forecast cost of gas for the purposes of determining the total revenue requirements for 2027. The cost of gas shown in Table 4-1 does not include the Renewable Natural Gas (RNG) supply costs associated with FEI's RNG Blend service and Voluntary RNG service. Pursuant to Decision and Order G-77-24,[15] RNG supply costs are now captured in the RNG Account and recovered from customers under RS 1 to 7 and 46 through the S&T RNG Rider 8, and from customers under the Voluntary RNG service[16] through the RNG Charge. Similar to the commodity gas recovery charge and S&T charges, FEI seeks approval of the RNG Blend percentage, the S&T RNG Rider 8 and the RNG Charge in separate applications to the BCUC.

Table 4-1: Forecast Cost of Gas at Existing Rates[17]

Cost of Gas ($ millions)	2026 Approved	2026 Projected	2027 Forecast
Residential[1]	$ 278.334	$ 252.500	$ 235.623
Commercial[2]	201.376	178.230	166.469
Industrial[3]	84.549	84.212	77.779
Total	**$ 564.259**	**$ 514.942**	**$ 479.871**

[14] Pursuant to Directive 4.c. of Order G-69-25, FEI is directed to "Submit the CMAE budget for approval, as well as review of prior year's forecast to actuals, as a separate application at or near the same time as FEI's third quarter gas cost report and remove these items from the Annual Reviews".

[15] Page 81.

[16] Voluntary RNG service under RS 1RNG, 2RNG, 3RNG, 3VRNG, 5RNG, 5VRNG, 7RNG, 7VRNG, 11RNG, and RS 46.

[17] Cost of gas from transportation customers (i.e., RS 22, 23, 25 and 27) is resulting from unaccounted for gas (UAF).

Notes to table:

[1] Includes Rate Schedule 1.

[2] Includes Rate Schedules 2, 3, and 23.

[3] Includes Rate Schedules 4, 5, 6, 6P, 7, 22, 25, 27, and 46.

The 2026 Approved, 2026 Projected, and 2027 Forecast cost of gas amounts shown in Table 4-1 above are based on the following:

- The 2026 Approved cost of gas was included as part of the Annual Review for 2025 and 2026 Delivery Rates which was filed with the BCUC in July 2025. It was calculated based on:
  - The 2026 Approved demand, less the volume associated with the RNG Blend, which was approved at 3 percent effective July 1, 2025;[18]
  - The approved commodity cost recovery charge of $2.230 per GJ effective July 1, 2025[19]; and
  - The approved S&T charges applicable to RS 1 to 7 and 46 effective January 1, 2025.[20]
- The 2026 Projected cost of gas is calculated based on:
  - The 2026 Projected demand described in Section 3 of the Application, less the volume associated with the RNG Blend, which was approved to be set at 3 percent effective July 1, 2025 and at 3.5 percent effective July 1, 2026;[21]
  - The approved commodity cost recovery charges of $2.230 per GJ, effective January 1, 2026[22] and $1.660 per GJ, effective April 1, 2026;[23] and
  - The approved S&T charges applicable to RS 1 to 7 and 46 by Order G-285-25, effective January 1, 2026.[24]
- The 2027 Forecast cost of gas is calculated based on:
  - The 2027 Forecast demand described in Section 3 of the Application, less the volume associated with the RNG Blend, which is currently set at 3.5 percent, as discussed above;

[18] Order G-181-25.

[19] By Letter L-9-25, FEI was approved to maintain the commodity cost recovery charge at the existing rate of $2.230 per GJ, effective July 1, 2025.

[20] Order G-88-25.

[21] Order G-131-26 approved a 3.5 percent RNG Blend, effective July 1, 2026.

[22] Order G-285-25.

[23] Order G-50-26. By Order G-130-26, FEI was approved to maintain the commodity cost recovery charge of $1.660 per GJ, effective July 1, 2026.

[24] E.g., the approved S&T charge applicable to RS 1, effective January 1, 2026, is $1.347 per GJ.

- The currently approved commodity cost recovery charge of $1.660 per GJ effective April 1, 2026, as discussed above; and
- The currently approved S&T charge applicable to RS 1 to 7 and 46, effective January 1, 2026, as discussed above.

The cost of gas shown in Table 4-1 above also includes the costs related to unaccounted for gas (UAF), which refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. Sources of UAF comprise, but are not limited to, system leakage, lost gas (i.e., gas lost as a result of utility and third-party activities, including gas theft), and measurement inaccuracies. The cost of UAF related to the Sales rate classes is recovered from Core customers[25] (i.e., RS 1 to 7 and 46) via the S&T charges. The cost of UAF related to the Transportation Service rate classes (i.e., RS 22, 23, 25, and 27) is included in the determination of their delivery rates to facilitate recovery of UAF costs as they do not pay S&T charges.

[25] Core customers are those for whom FEI is obligated to ensure the purchase, transportation, and uninterrupted delivery of natural gas to their premises.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FEI's forecasts of Other Revenue. In the RSF Decision (page 18), the BCUC approved that forecast variances in certain components of Other Revenue were to be subject to earnings sharing. These components include Late Payment Charges, Application Charges, NSF Returned Cheque Charges, Other Recoveries, and NGT Overhead and Marketing Recoveries. The remaining components of Other Revenue continue to receive flow-through treatment of variances between forecast and actual results, consistent with the treatment during the 2020-2024 MRP term.

As shown in Table 5-1 below, FEI is forecasting a slight decrease in Other Revenue for 2027 of approximately $0.292 million compared to 2026 Approved, primarily due to lower forecast NGT related recoveries.

Table 5-1: Other Revenue Components ($ millions)

	2026 Approved	2026 Projected	2027 Forecast
Late Payment Charge	$ 3.511	$ 3.447	$ 3.474
Application Charge	1.533	1.533	1.480
NSF Returned Cheque Charges	0.028	0.028	0.028
Other Recoveries	0.288	0.300	0.300
NGT Related Recoveries	3.738	3.416	3.429
RNG Other Revenue	7.592	7.358	7.687
SCP Third Party Revenue	13.284	13.284	13.284
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**$ 48.013**	**$ 47.405**	**$ 47.721**

In the following sections, FEI summarizes the methods used to forecast the line items included in the table above.

5.2 OTHER REVENUE COMPONENTS

5.2.1 Late Payment Charge

The 2026 Projected Late Payment Charges are lower than 2026 Approved. The 2026 Projected Late Payment Charges are calculated based on the average of the 2024 and 2025 Actual amounts, which are $3.393 million and $3.501 million, respectively.

Consistent with the method approved in the RSF Decision,[26] the 2027 Forecast for Late Payment Charges is calculated based on the average of the 2025 Actual Late Payment Charges of $3.501 million and the 2026 Projected amount of $3.447 million. This results in a forecast increase in Late Payment Charges of $0.027 million compared to 2026 Projected.

5.2.2 Application Charge

Application Charges are calculated based on the application fees specified in FEI's rate schedules applied to new customer connections or current customer reconnections. The 2026 Projected amount is consistent with 2026 Approved. The 2027 Forecast is slightly less than 2026 Projected (i.e., a decrease of $0.053 million).

5.2.3 NSF Returned Cheque Charges and Other Recoveries

The 2026 Projected and 2027 Forecast amounts for NSF Returned Cheque Charges are consistent with 2026 Approved levels. For the Other Recoveries, FEI is projecting/forecasting a small increase (approximately $0.012 million) for 2026 and 2027 related to the inclusion of the AMI radio-off meter read fees. These fees were implemented effective February 1, 2025, pursuant to Order G-330-24.

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing (OH&M) charge that is applied to FEI fuelling station customers, tanker rentals from LNG customers, and CNG and LNG fuelling stations (CNG & LNG Service Revenues) as shown in Table 5-2 below. Variances between forecast and actual NGT Overhead and Marketing Recoveries are subject to earnings sharing. Variances in the NGT Tanker Rental Revenue and CNG & LNG Service Revenues are treated as flow-through, with the variances captured in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2026 and 2027 NGT Related Recoveries ($ millions)

	2026 Approved	2026 Projected	2027 Forecast
NGT Overhead and Marketing Recovery	$ 0.228	$ 0.220	$ 0.203
NGT Tanker Rental Revenue	1.067	0.970	1.089
CNG & LNG Service Revenues	2.443	2.226	2.137
Total NGT Related Recoveries ($ millions)	**$ 3.738**	**$ 3.416**	**$ 3.429**

The following subsections discuss each of the NGT related recoveries.

[26] RSF Decision and Order G-69-25, p. 56.

5.2.4.1 NGT Overhead and Marketing Recovery

Pursuant to Order G-78-13, FEI has included a forecast of OH&M recoveries from FEI's NGT fuelling station customers. As shown in Table 5-3 below, the 2026 Projected NGT OH&M revenue is $0.220 million and the 2027 Forecast NGT OH&M revenue is $0.203 million. This revenue is calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[27] 2026 Projected and 2027 Forecast sales volumes of CNG and LNG stations.

The decrease in both 2026 Projected and 2027 Forecast reflects the buy-out of two CNG stations during 2026. For Less Disposal Inc. (For Less) and GFL Environmental Inc. (GFL) bought out their CNG Fuelling Stations in March and July 2026, respectively. While both For Less and GFL continue to operate at these stations under RS 5, FEI is no longer recording recoveries under the stations' capital and O&M rates.

Table 5-3: NGT Overhead and Marketing Revenue Forecast ($ millions)

	2026 Approved	2026 Projected	2027 Forecast
Applicable Volume (GJ)	439,392	423,747	391,089
Rate ($/GJ)	0.520	0.520	0.520
Total NGT OH&M Revenue ($ millions)	**$ 0.228**	**$ 0.220**	**$ 0.203**

5.2.4.2 NGT Tanker Rental Revenue

Table 5-4 below shows the tanker rental revenue for each type of FEI-owned tanker based on the currently approved RS 46 tanker rental rates.

Table 5-4: LNG Tanker Rental Revenue ($ millions)

	2026 Approved	2026 Projected	2027 Forecast
Standard Tanker Rental Deliveries	12	14	9
Rate ($/Delivery)	$ 352	$ 353	$ 360
Sub Total ($ millions)	**$ 0.004**	**$ 0.005**	**$ 0.003**
Tridem Tanker Rental Deliveries	-	-	-
Rate ($/Delivery)	$ n/a	$ n/a	$ n/a
Sub Total ($ millions)	**$ n/a**	**$ n/a**	**$ n/a**
Marine Equipped Tridem Tanker Rental Deliveries	1,792	1,624	1,792
Rate ($/Delivery)	$ 593	$ 594	$ 606
Sub Total ($ millions)	**$ 1.063**	**$ 0.965**	**$ 1.086**
Total Tanker Rental Revenue ($ millions)	**$ 1.067**	**$ 0.970**	**$ 1.089**

Consistent with prior years, FEI is forecasting minimal standard tanker rental revenue for 2027. The decrease in the 2027 Forecast deliveries is due to anticipated maintenance activities, which

[27] For host customers with CNG or LNG delivered through an FEI-owned CNG or LNG fueling station, the applicable volume for OH&M is limited to the contract minimum volume. For third-party fueling customers, all volume is applicable for OH&M.

will impact the availability of the standard tanker, as well as a forecast reduction in customer demand.

Regarding the Tridem tankers, as explained in previous Annual Reviews, these tankers are primarily used for long haul deliveries in Canada, such as to the Yukon, and they are not permitted in the US (due to weight restrictions in the US). Given these restrictions and that FEI did not expect Canadian deliveries to occur outside of BC, FEI sold the single Tridem tanker at the end of 2023 and retired it from FEI's rate base, with all gains from the sale returned to FEI's customers.

For the Marine Equipped Tridem tankers, the 2026 Projected revenue is lower than 2026 Approved, primarily due to outages and maintenance associated with marine customers, which reduced their deliveries in 2026. For 2027, FEI is forecasting deliveries to return to 2026 Approved levels.

5.2.4.3 CNG and LNG Service Revenue Forecast

The CNG and LNG Service Other Revenue forecast includes the FEI-owned CNG and LNG fuelling station recoveries (i.e., capital, O&M, and short-term fuelling rates) at the contracted minimum take-or-pay volumes of each station. Table 5-5 below provides a breakdown of the CNG and LNG fuelling station recoveries. The forecast of station recoveries as Other Revenue does not include recoveries from spot volume and excess volume (i.e., a fuelling customer uses more than their contracted minimum take-or-pay volume).[28]

Table 5-5: CNG and LNG Fuelling Service Station Revenue Forecast ($ millions)

	2026 Approved	2026 Projected	2027 Forecast
CNG Station	$ 2.243	$ 2.017	$ 1.924
LNG Station	0.035	0.044	0.045
Subtotal - NGT Stations ($ millions)	**$ 2.278**	**$ 2.061**	**$ 1.969**
Surrey Ops CNG Pump	0.166	0.165	0.168
Total ($ millions)	**$ 2.443**	**$ 2.226**	**$ 2.137**

For CNG stations, both the 2026 Projected and 2027 Forecast station revenues are lower than 2026 Approved, primarily due to the buy-out of the For Less CNG station and the GFL CNG station in 2026, as discussed in Section 5.2.4.1.

For LNG stations, the increase from 2026 Approved to 2026 Projected is primarily due to increased recoveries from the Vedder at Vye Road LNG fuelling station. For the 2027 Forecast, the small increase is due to the approved annual escalation in the fuelling rates at each station (i.e., the capital rate escalates at 2 percent per year, and the O&M rate escalates by BC CPI each year).

[28] Station revenue recoveries from spot and excess volume are recorded in the CNG and LNG Recoveries deferral account. CNG and LNG Station recoveries under minimum take-or-pay contracts are recorded in Other Revenue.

FEI notes that, pursuant to Order G-162-25 which approved the discontinuance of the operation of the Vedder Abbotsford Fuelling Station, FEI was directed to provide an update regarding the recovery of the unrecovered capital cost of the station. FEI and Vedder are at the final stage of negotiating the settlement agreement and FEI expects to finalize and execute the settlement before the end of 2026. Upon executing the settlement agreement, the Vedder Abbotsford Fuelling station will be retired, and FEI will credit the book value of the station to FEI's plant in service, record the removal costs in the Net Salvage Provision/Cost deferral account, and record the remaining balance, including the excess capital credits to Vedder, in the CNG & LNG Recoveries deferral account.

5.2.5 RNG Other Revenue

In accordance with Order G-210-13, which approved the RNG Program (formerly referred to as the Biomethane Program) on a permanent basis, the following delivery margin related costs are recorded in the RNG account:[29]

- Upgrading plant cost of service; [30]
- Interconnection cost of service; and
- Program overhead costs.[31]

The RNG Other Revenue represents the transfer of the earned return and income tax components of the cost of service of FEI's RNG capital assets from the delivery margin to the RNG Account.

The 2026 Projected RNG Other Revenue is $0.234 million less than 2026 Approved. The primary drivers of the variance are higher actual capital additions related to the Capital Regional District RNG Project in 2025 and increased projected capital additions for the Kelowna Upgrader RNG Project in 2026. These higher capital expenditures result in greater CCA deductions in 2026, which generate higher income tax credits. The income tax credits offset the income tax associated with RNG capital assets, thereby reducing overall RNG Other Revenue that is transferred to the RNG Account. The 2026 Projected amount of $7.358 million consists of $6.568 million related to earned return and $0.790 million related to income tax.

The 2027 Forecast of $7.687 million consists of $6.533 million in earned return and $1.154 million in total income tax expense to be transferred to the RNG Account. The increase from the 2026 Projected amount is mainly due to the City of Vancouver (COV) Landfill RNG project, which will no longer benefit from the enhanced first-year allowance under Canada's Accelerated Investment Incentive Program (AIIP)[32], as the project will be in its third year of operation in 2027. As a result,

[29] Renamed from the Biomethane Variance Account (BVA) to the RNG Account pursuant to Order G-77-24.
[30] The cost of procuring RNG supply does not need to be transferred because it is accounted for directly in the RNG Account.
[31] Program costs as defined in Order G-210-13 include education, marketing, direct administration, cost of enrollment and the cost of IT upgrades.
[32] For 2025, the enhanced first-year allowance is 75 percent for clean energy equipment: https://www.canada.ca/en/revenue-agency.

the CCA deductions are expected to decline in 2027, leading to higher income tax associated with these RNG capital assets. This increase in income tax expense, in turn, results in higher overall RNG Other Revenue.

5.3 SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE

The SCP Third Party Revenue includes the items shown in the table below.

Table 5-6: SCP Revenue Components ($ millions)

	2026 Approved	2026 Projected	2027 Forecast
MCRA	$ 13.284	$ 13.284	$ 13.284
Net Other Mitigation - West to East Capacity	-	-	-
Total SCP Revenue	**$ 13.284**	**$ 13.284**	**$ 13.284**

The components of the SCP Third Party Revenue shown in Table 5-6 are discussed separately below. Any variances from the forecast SCP Third Party Revenues will continue to be recorded in the SCP Net Mitigation Revenues Variance Account and returned to or recovered from customers over a two-year period.

5.3.1 Midstream Cost Reconciliation Account (MCRA)

The 2026 Projected and 2027 Forecast Other Revenue of $13.284 million is related to the inclusion of the 105 MMcfd of SCP east to west capacity in the MCRA portfolio.

As part of the Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20,[33] FEI was approved, effective November 1, 2020, for the duration of the 2020-2024 MRP term, to debit the MCRA and credit Other Revenue in the amount of $346.617 per MMcfd for the 105 MMcfd of SCP east to west capacity held within the gas supply midstream portfolio.

Pursuant to Order G-287-25,[34] FEI is approved to continue debiting the MCRA and crediting Other Revenue in the amount of $346.617 per MMcfd, effective January 1, 2025, for the duration of the 2025-2027 RSF term.

5.3.2 Net Other Mitigation Revenue

FEI has been seeking, and will continue to seek, opportunities to contract the west to east capacity on the SCP.

Mitigation revenue generated from the SCP west to east capacity ties to market price differentials during the summer months and reflects the existing pipeline capacity within the region. The mitigation revenue forecast is net of the cost of using FEI gas supply resources, such as the

[33] Directive 7 of Order G-319-20.
[34] Directive 4 of Order G-287-25.

Westcoast Energy Limited Partnership Kingsvale South transportation capacity held in the midstream portfolio, to connect with the SCP system. The mitigation revenue net of the gas supply resource costs is allocated to Other Revenue.

The forecast mitigation revenue for the SCP west to east capacity for 2027 is based on the forward market price differentials for summer 2027. Huntingdon remains a higher priced market than Kingsgate, thus supporting east to west movement across SCP during the summer rather than west to east flow. Therefore, FEI forecasts generating no west to east mitigation revenue in 2027.

5.4 LNG CAPACITY ASSIGNMENT

The $18.039 million in LNG capacity assignment Other Revenue shown in Table 5-1 represents a transfer of costs from the delivery margin to gas costs, reflecting the allocation of a portion of the Mt. Hayes LNG facility costs to gas costs.

The Mt. Hayes cost allocations were reviewed during the FEI 2016 Rate Design Application proceeding. The BCUC approved FEI's proposal to continue to allocate costs based on the Mt. Hayes LNG facility having a dual purpose serving as a gas supply storage facility and as a transmission facility providing additional transmission system capacity.[35]

5.5 SUMMARY

FEI has forecast the Other Revenue components for 2027 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue are recorded in the CNG/LNG Recoveries deferral account (for excess revenue from the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4.3), the RNG Account (for variances in the items discussed in Section 5.2.5), the SCP Net Mitigation Revenues Variance Account (for variances in the items discussed in Section 5.3), and the Flow-through deferral account (for all variances from forecast in Sections 5.2.4.2 and 5.4 as well as any remaining variances from forecast in Section 5.2.4.3). All other variances in Other Revenue are shared with customers through the Earnings Sharing Mechanism.

[35] The cost allocation for the Mt. Hayes LNG facility was approved pursuant to Order G-4-18 and the Reasons for Decision attached as Appendix A, both dated January 9, 2018.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the RSF, FEI's O&M expense is primarily determined by formula, with the addition of certain items that are forecast outside the formula on an annual basis.

The 2027 Formula O&M is $329.218 million, representing a 1.6 percent increase from the 2026 Formula O&M, driven by an increase in the 2027 net inflation factor but partially offset by a decrease in the average customer count forecast from 2026 Approved to 2027 Forecast.

For the O&M expenses tracked outside of the formula (i.e., forecast O&M), the 2027 Forecast O&M is $94.180 million, representing a 3.1 percent increase from 2026 Approved. The drivers of the increase are pension and OPEB expense, integrity O&M and increased expenditures for Clean Growth Initiatives, which are partially offset by decreases in insurance expense, the AMI flow-through O&M, and BCUC levies.

Overall, the increase in gross O&M expense from 2026 Approved to 2027 Forecast is 1.9 percent. The components of the 2027 O&M expense are shown in Table 6-1 below.

Table 6-1: 2027 O&M Expense ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast	Reference
1	Formula O&M	$ 324.105	$ 324.105	$ 329.218	Section 11, Schedule 20, Line 12
2	Forecast O&M	91.321	93.788	94.180	Section 11, Schedule 20, Line 24
3	Total Gross O&M	415.426	417.893	423.398	Line 1 + 2
4	Capitalized Overhead	(60.237)	(60.237)	(61.393)	Section 11, Schedule 20, Line 28
5	O&M transferred to RNG Account	(7.946)	(7.777)	(8.978)	Section 11, Schedule 20, Line 27
6	Net O&M	$ 347.243	$ 349.879	$ 353.027	Sum of Lines 3 to 5

In the sections below, FEI provides further details on its formula and forecast O&M expenses for 2027.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M is calculated based on the prior year's Approved Base UCOM, escalated by the inflation factor (I-Factor) less the X-Factor of 0.55 percent, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

For 2027, the formula O&M is calculated as follows:

2026 Base UCOM x [1 + (I Factor – X Factor)] x [2027 Forecast Average Customer Count]
+ 2025 Formula O&M True-up

As discussed in Section 2 of the Application, the 2027 net inflation factor based on prior year's BC-CPI and BC-AWE, less the X-Factor, is 1.901 percent.

Table 6-2 below shows the calculation of the 2027 Formula O&M, including the calculation of the 2025 Formula O&M true-up.

Table 6-2: Calculation of 2027 Formula O&M ($ millions)

Line No.	Description	2027 Forecast	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	$ 290	G-287-25 2025-2026 Annual Review
2	Net Inflation Factor	1.901%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	$ 296	Line 1 x (1 + Line 2)
4	Average Customer Forecast	1,113,600	Sch 3, Line 20
5	Inflation-Indexed O&M before True-up	$ 329.625	Line 3 x Line 4 / 1,000,000
6	2025 True-up O&M	(0.407)	Line 14
7	Inflation-Indexed O&M	$ 329.218	Line 5 + 6
8			
9	2025 O&M True-up		
10	2025 Actual 12 month Average Customers	1,101,521	Table 2-2 Line 25
11	2025 Forecast 12 month Average Customers	1,102,958	Table 2-2 Line 24
12	Difference (True-up)	(1,437)	Line 10 - 11
13	2025 Unit Cost ($/customer)	$ 283	G-287-25 2025-2026 Annual Review
14	O&M True-up for 2027	$ (0.407)	Line 12 x Line 13 / 1,000,000

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

In addition to FEI's formula O&M, FEI forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance, integrity O&M, AMI-related O&M, BCUC levies, and O&M supporting Clean Growth Initiatives, as well as any exogenous factors. These amounts are shown in Table 6-3 below along with a comparison to 2026.

Table 6-3: 2027 Forecast O&M ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Pension/OPEB (O&M Portion)	$ 5.725	$ 5.725	$ 6.598
2	Insurance	12.748	11.816	11.665
3	Integrity O&M	12.000	12.900	15.400
4	AMI Flowthrough O&M	25.578	26.334	21.386
5	BCUC Levies	8.208	7.642	7.453
6	**Clean Growth Initiatives:**			
7	RNG O&M	7.946	7.777	8.978
8	Renewable Gas Development	5.084	5.400	5.510
9	NGT O&M	2.994	2.934	3.221
10	Variable LNG Production	11.038	13.260	13.969
11	Total Forecast O&M	$ 91.321	$ 93.788	$ 94.180

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-138-14. Variances in BCUC fees are captured in the BCUC Levies Variance deferral account and amortized into rates in the subsequent year. Variances in insurance, integrity O&M, AMI-related O&M, Clean Growth Initiatives and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense is based on actuarial estimates using a range of assumptions provided by FEI's actuary. In addition to O&M, pension and OPEB expense is embedded in capital expenditures, asset removal costs, and CMAE categories, as shown in Table 6-4.

Table 6-4: Pension and OPEB Expense ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	O&M	$ 5.725	$ 5.725	$ 6.598
2	Capital - Growth	1.095	1.095	1.012
3	Capital - Other	3.225	3.225	2.981
4	Deferred - Asset Removal Costs	1.272	1.272	1.176
5	Deferred - CMAE	0.384	0.384	0.355
6	Total	$ 11.701	$ 11.701	$ 12.123

The total 2027 Forecast pension and OPEB expense is $0.422 million higher than 2026 Approved. This increase is primarily due to the following:

- An increase in interest costs of $5.226 million, primarily due to an increase in the actuarially determined discount rate from 4.75 percent to 5.00 percent; and
- A decrease in the amortization of actuarial gains and prior year service credits.

These increases are partially offset by:

- A decrease of approximately $1.805 million driven by lower current service costs, which also results from the higher discount rate; and
- A higher expected return on assets of $3.418 million, reflecting continued growth in pension plan asset values.

6.3.2 Insurance Expense

Insurance expense relates to the insurance premium expense allocated to FEI by Fortis Inc. as set out in Table 6-5 below.

Table 6-5: Insurance Expense ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Insurance Premium	$ 12.748	$ 11.816	$ 11.665

FEI's annual insurance renewal occurs in July of each year. The 2026 Projected insurance premium expense of $11.816 million is $0.932 million lower than the 2026 Approved, as it incorporates FEI's actual July 2025 to June 2026 insurance renewals (for the months of January to June 2026) and FEI's actual July 2026 to June 2027 insurance renewals (for the months of July to December 2026).

The 2027 Forecast insurance premium expense is $11.665 million, which is a decrease of $0.151 million from 2026 Projected. The 2027 Forecast is calculated based on the actual insurance renewal from July 2026 to June 2027 plus 5 percent escalation for the insurance renewal from July 2027 to June 2028.[36]

6.3.3 Integrity O&M

As part of the RSF Decision[37], FEI was approved to continue to treat integrity digs as a flow-through item with variances between forecast and actual amounts captured in the Flow-through deferral account.

As shown in Table 6-3 above, the 2026 Projected Integrity O&M is $12.9 million, which is $0.9 million higher than 2026 Approved. The main drivers of the increase in 2026 Projected integrity digs compared to 2026 Approved are:

- Higher site-specific costs associated with digs in city roadways and non-capitalized pipeline repairs;
- Regulatory requirements associated with water management which are increasing costs at a dig site in the vicinity of Burns Bog in Delta. The projection for this dig site is approximately $1 million;
- Helicopter-only access is required for a particular integrity dig site in a remote mountainous area on Vancouver Island, resulting in a projected cost for this site of approximately $1.4 million. To avoid future dig costs at this site, FEI is addressing a total of four features in 2026; and
- FEI is projecting one additional Facilities dig in 2026 compared to 2026 Approved. Compared to typical digs on linear pipeline assets, Facilities digs are more complex and time consuming to complete the excavation and pipe inspection as they typically

[36] 2027 Forecast: $5.691 million (first 6 months in 2027) x 1.05 = $5.975 million. $5.691 million + $5.975 million = $11.665 million.

[37] RSF Decision and Order G-69-25, p. 18.

encompass relatively longer lengths of pipe at a single site and occur in congested fenced facilities. Facilities digs are typically forecast at approximately $0.5 million per dig.

These increases are partially offset by the following:

- FEI is projecting an overall reduced number of integrity digs for 2026, which has contributed to a projected reduction in integrity dig costs of approximately $1.2 million. There are fewer projected digs in the categories of ILI Digs – New Tool(s) and ILI Digs – New Practice(s) than originally forecast, reflecting FEI's analysis of recently received in-line inspection (ILI) data. Also contributing to this reduction was a delayed in-line inspection associated with the Inland Gas Upgrade (IGU) Project. The pipeline was not available ILI as originally expected in 2025 due to archaeological permitting issues. With the inspection moved to 2026, a number of digs on this line have been moved into 2027.

The 2027 Forecast Integrity O&M is $15.4 million, which is an increase of $2.5 million from 2026 Projected. As shown in Table 6-6 below, FEI is forecasting an increase in the number of integrity digs for 2027 (156 digs in 2027 compared to 107 projected for 2026). As further discussed below, these increases are forecast to occur in the categories of New Tools, New Practices, Established Tools and Practices, and Non-ILI.

Table 6-6 below provides the forecast number of integrity digs with Reason for Dig categories as well as the total cost and average cost per dig. The table identifies integrity digs associated with ILI activities (lines 1 to 3), and digs resulting from other reasons (lines 4 and 5). FEI discusses the factors impacting the number of digs below the table.

Table 6-6: Integrity Digs Activities and Expenditures

Line No.	Reason for Digs	2025 Actual	2026 Approved	2026 Projected	2027 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.	56	59	41	53
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.	17	15	3	14
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices	35	36	52	72
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys.	6	6	8	15

Line No.	Reason for Digs	2025 Actual	2026 Approved	2026 Projected	2027 Forecast
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.	2	2	3	2
6	**Total Integrity Digs**	**116**	**118**	**107**	**156**
7	**Total Integrity Dig Expenditures ($ millions)**	**12.0**	**12.0**	**12.9**	**15.4**
8	Average Cost per Dig ($000s)	104	102	121	99

There continues to be significant uncertainty with respect to the number and complexity of integrity digs. FEI provides the following discussion for each Reason for Dig shown in Table 6-6 above.

- **ILI Digs – New Tool(s)** is an estimate of the integrity digs resulting from first-time in-line inspections. FEI is scheduled to complete four baseline in-line inspections (totalling over 320 km of pipe) associated with the Coastal Transmission System (CTS) and Interior Transmission System (ITS) Transmission Integrity Management Capabilities (TIMC) Projects in 2026, with subsequent integrity digs expected to occur in both 2027 and 2028. The 2027 Forecast for ILI Digs – New Tool(s) includes 29 digs to mitigate cracking identified through the first ITS TIMC baseline inspections, with the remainder being primarily associated with the CTS TIMC and IGU baseline inspections. Pipeline condition and inspection success are unknown until after the first-time ILI tool runs are completed and data is analyzed by FEI; as such, FEI has based its forecast on the engineering judgement of qualified staff informed by various information sources including:
    - Knowledge of populations of imperfections from other in-line inspected pipelines;
    - Estimates of pipeline-specific crack susceptibility (e.g., the projected dig rate used for the ITS is approximately twice the rate used for the CTS); and
    - Estimates of timing of ILI activities, with a primary input being the timing of the IGU, CTS TIMC and ITS TIMC Project activities, to prepare pipelines for running ILI tools.
- **ILI Digs – New Practice(s)** continue to be influenced by the adoption of the strain-based criteria for dents as per current industry practice and standards. FEI's 2027 Forecast incorporates the analysis to date. The estimated number of digs in 2027 reflects FEI's forecast on Interior pipelines for which ILI data and/or analysis is not yet available.
- **ILI Digs – Established Tools and Practices** result from FEI's analysis of its existing technology tool runs, which are currently scheduled on a maximum seven-year interval but may vary from year to year depending on pipe condition. As other tool technologies (e.g., EMAT) become established and included in a similar re-run schedule, FEI's estimates of ongoing ILI digs will also include integrity digs identified through those tools.

The 2027 Forecast incorporates FEI's ILI analysis and integrity dig results to date. The 2027 Forecast is higher than past years because approximately 80 percent of the digs forecast in 2027 are on FEI's earliest-constructed transmission pipelines (1956 and 1957) which are requiring more digs.

- **Non-ILI Digs** reflect assessments of transmission pipelines for which ILI tools are not currently proven, commercialized and adopted, and hence are identified through other methods (such as cathodic protection surveys). The number of these digs is expected to vary depending on factors such as survey results from the previous year(s), the timing of surveys and other potential indications of pipeline condition warranting this level of investigation (e.g., leaks). The increased number of digs forecast for 2027 is a result of FEI's ongoing response to six minor leaks since 2022 on the NPS 3 Fernie Lateral. As a BC Energy Regulator (BCER) permit holder, FEI's obligation under section 37(1) of the *BC Energy Resource Activities Act* is to "prevent spillage" associated with its energy resource activities. Integrity digs are necessary for FEI to understand whether it can sufficiently mitigate the potential for future leaks through its ongoing non-ILI program.
- **Facilities Digs** reflect assessments of pipe condition within facility sites such as compressor stations and control stations. Consistent with its current practices for assessing linear pipeline assets, this category of digs includes underground piping within facilities that is capable of failure by rupture but is not capable of ILI. Facilities digs can encompass relatively longer lengths of pipe at a single site (relative to typical digs on linear pipeline assets). FEI is forecasting two Facilities digs in 2027, prioritized on the basis of factors including construction (e.g., age, expected external coating) and operating characteristics (e.g., station criticality, operating stress).

Site-specific and broader factors that impact FEI's average cost per dig include the number and proportion of digs:

- in urban versus rural areas;
- in difficult-to-access areas;
- requiring right-of-way encroachment removal;
- on larger diameter versus smaller diameter pipelines;
- requiring incremental environmental planning and management;
- in proximity to areas of high archaeological potential;
- requiring more complex operating procedures to prepare for the dig;
- requiring incremental in-ditch pipeline assessment; and
- subject to a non-capitalized repair.

Although it is difficult to generalize the above factors between FEI's operating regions, the Interior region tends to have a greater proportion of digs in rural areas, and sites are typically less congested and easier to access, which generally results in a lower average cost per dig. The 2027 Forecast cost per dig is influenced by factors including a greater proportion of digs forecast in the Interior compared to 2026, which means there is a greater likelihood of lower unit costs.

FEI, in alignment with other transmission pipeline operators, continually explores opportunities to optimize lifecycle costs of pipeline operation. FEI has adopted alternate pipeline repair products in recent years that have enabled the avoidance of either a more costly non-capitalized repair or capital pipe replacement, resulting in a lower overall cost.

Integrity digs are not discretionary. FEI meets its obligations by completing digs as follows:

- When FEI has specific knowledge of ILI tool-reported features that may require repair, FEI digs to assess the pipe condition relative to CSA Z662:23 Clause 10.10 defect assessment criteria. FEI is obligated to repair or cut out defects in order to remain compliant with this national consensus standard that is adopted as mandatory through the BC Pipeline Regulation (B.C. Reg. 281/2010).
- When FEI's analysis of an ILI tool-reported feature demonstrates the potential for future failure, FEI digs to assess the potential for future rupture or leak.
- When FEI requires data to assess ILI tool performance, including the potential for tool reporting bias (i.e., tool uncertainty), FEI completes ILI tool validation digs.
- When FEI's assessment of above-ground survey data identifies potential corrosion or other integrity concerns, 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 other available and relevant technical information, including observations of potential hazards (e.g., unauthorized external loading above a pipeline, visual observation of ground movement).

Continued safe operation of FEI's aging transmission system, constructed as early as the 1950s, is supported by FEI's spending in O&M integrity activities.

6.3.4 AMI O&M

For the term of the RSF, FEI is approved to reclassify its O&M costs impacted by the AMI CPCN Project from formula to flow-through. Deployment of new AMI meters began in 2025 and is forecast to complete in 2028.

Table 6-7: AMI O&M Expense ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Meter Installation	$ 1.301	$ 2.066	$ 2.077
2	Meter Reading	16.000	16.640	10.700
3	Operations	2.230	2.547	2.494
4	Customer Service	1.343	1.569	1.394
5	Subtotal	$ 20.874	$ 22.822	$ 16.665
6	New AMI Activities	4.704	3.512	4.721
7	Total AMI O&M	$ 25.578	$ 26.334	$ 21.386

As shown in Table 6-7 above, the 2026 Projected costs are $26.334 million and the 2027 Forecast costs are $21.386 million. FEI provides further discussion of each category below.

- **Meter Installation O&M:** This is the portion of meter installation costs that are being completed by FEI's Operations instead of the AMI Project deployment vendor, as discussed in the AMI Project CPCN application.[38] FEI Operations is on track to complete more meter installations for 2026 Projected than originally anticipated. In 2027, FEI expects to complete a similar level of meter installations as 2026 Projected, resulting in a similar level of meter installation O&M costs. FEI notes that 14 percent of the meter exchange costs completed by FEI Operations are allocated to O&M, with the remaining capitalized.
- **Meter Reading O&M:** This is the primary component of the AMI O&M and consists of the manual costs of reading meters and the cellular costs for current large commercial and industrial meters. The 2026 Projected Meter Reading O&M includes Olameter's cost to perform manual meter reads. As of June 2026, fewer meters than anticipated have been transitioned to automatic reads, resulting in more manual meter reads. As the deployment of new AMI meters being read automatically increases, FEI is forecasting a reduction in meter reading costs in 2027 compared to 2026 Projected.
- **Operations O&M:** This is the cost for activities completed by FEI's field crews that are impacted by the AMI Project, specifically: meter trouble calls, meter reads, meter identifications, disconnects, unlocks, cathodic protection data gathering, and odour measurement. The increase from 2026 Approved to 2026 Projected is due to higher labour rates and increased meter exchange activities associated with the AMI Project. FEI expects that these activities will remain at a similar level in 2027.
- **Customer Service O&M:** This is the cost for the customer service activities impacted, including billing investigation and exceptions, meter reading coordinator workload, vacant premise processing, and meter switching identification and validation. The 2026 Projected O&M is higher than 2026 Approved as a higher volume of these activities has been experienced than expected during the meter switching process. FEI is forecasting a

[38] FEI AMI CPCN Project Application, Exhibit B-1, Section 6.2.2.2, p. 106.

decrease in these costs in 2027 compared to 2026 Projected as the AMI meters are deployed.

- **New AMI Activities:** These are new costs incurred as a result of the AMI Project which include incremental internal labour, network and software costs, as discussed in the AMI Project CPCN application.[39] These new O&M costs will be phased in as the AMI Project is deployed. The 2026 Projected costs are lower than 2026 Approved primarily due to a shift in the deployment timing and ramp up period for the base stations from 2026 to 2027. For 2027, the increase from 2026 Projected is primarily due to the deferred base stations from 2026 being completed in 2027. As the number of base stations being deployed increases in 2027, the FlexNet managed services fees will also increase. Further, the Production Environment SaaS fees and the Sensus Analytics licensing costs will increase in 2027 as more AMI meters will be communicating to the network by the end of 2027.

6.3.5 BCUC Levies

The 2026 Projected BCUC levies are $7.642 million. The 2026 Projected amount is based on the following:

- The levy amount in Order G-117-25 for the fourth quarter (Q4) of the BCUC's Fiscal 2025/26 year (January to March 2026); and
- For the remainder of 2026, the levy amount in Order G-123-26 for Q1 to Q3 of the BCUC's Fiscal 2026/27 year.

The 2027 Forecast for BCUC levies is $7.453 million. The 2027 Forecast is based on the annual levy amount in Order G-123-26, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2027/28 will not be available until early to mid 2027.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.6 Clean Growth Initiative – RNG O&M

A summary of the RNG O&M, by project, is provided in Table 6-8 below:

[39] FEI AMI CPCN Project Application, Exhibit B-1, Section 6.2.2.1, p. 106. Incremental internal labour consists of system engineers as well as network and software support personnel. Network costs consist of managed network services, radio licences, backhaul bandwidth, lease costs and network security. Software costs consist of Software as a Service (SaaS) fees, licence costs and internal software updates needed after the implementation of initial system enhancements.

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

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Program Overhead	$ 5.662	$ 6.266	$ 6.723
2	City of Surrey	0.014	0.014	0.026
3	Kelowna	0.587	0.661	0.694
4	Salmon Arm	0.390	0.144	0.151
5	Fraser Valley Biogas	0.013	0.013	0.026
6	Seabreeze Farms	0.015	0.015	0.026
7	Lulu Island WWTP	0.020	0.020	0.026
8	Dickland Farms	0.014	0.014	0.026
9	City of Vancouver	1.200	0.600	1.200
10	REN Energy	-	-	-
11	Capital Regional District	0.015	0.015	0.026
12	Delta RNG (MAS Energy)	0.015	0.015	0.053
13	Total RNG O&M	$ 7.946	$ 7.777	$ 8.978

The 2026 Projected RNG O&M is lower than 2026 Approved, primarily due to decreases in O&M for the Salmon Arm and City of Vancouver (COV) Landfill RNG projects. These decreases are partially offset by higher projected Program Overhead costs. The primary drivers of the increased Program Overhead costs are incremental labour and external costs (e.g., consulting and legal) related to carbon intensity verification for acquisitions of RNG that must meet carbon intensity verification requirements, including section 8.2 of the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR), and to support the development of the Canadian Low-Emission Energy Registry (CLEER).[40]

The increase in 2027 Forecast compared to 2026 Projected is primarily due to a full year of O&M costs for the COV Landfill RNG project, as the facility is expected to be at, or near capacity, for all of 2027, and an increase in Program Overhead. Similar to 2026 Projected, the primary drivers of the increased Program Overhead costs are incremental labour and external costs related to carbon intensity verification and registration in the CLEER.

Pursuant to Decision and Order G-77-24[41], RNG O&M is transferred to the RNG Account and recovered from customers under RS 1 to 7 and 46 through the S&T RNG Rider 8, which is reviewed by the BCUC in a separate application.

6.3.7 Clean Growth Initiative – Renewable Gas Development

FEI continues to progress various activities to enable the production and use of hydrogen and syngas, and the increased costs for renewable and lower carbon gas development reflect this

[40] CLEER is a centralized system that records production data for low-emission energy in Canada.
[41] Decision and Order G-77-24, p. 81.

increased work. Table 6-9 below provides the 2026 Approved, 2026 Projected, and 2027 Forecast of FEI's Renewable Gas Development O&M expenditures.

Table 6-9: Renewable Gas Development O&M ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Renewable Gas Development	$ 5.084	$ 5.400	$ 5.510

The 2026 Projected O&M is $5.400 million, which is $0.316 million higher than 2026 Approved. The increase in 2026 Projected is primarily due to FEI's plan to undertake a hydrogen development study to assess the practical requirements for deploying hydrogen fuel cell Class 8 trucks with a large fleet partner in BC. For 2027, FEI is forecasting an increase of $0.426 million from 2026 Approved. This increase is mainly related to FEI's plan to undertake a feasibility study to assess hydrogen fuelling options for CPKC[42] Rail.

FEI provides further details on the above studies and the other activities included in the 2026 Projected and 2027 Forecast O&M below.

- **Offtake Supply Opportunities (includes procurement feasibility):**
    - 2026 – continue evaluation of potential third-party proposals that are considering developing projects to produce clean hydrogen and syngas for supply to offtakes such as FEI. Review regulatory and permitting requirements to offtake hydrogen from third-party production facilities for distribution directly to industrial customers other than through the natural gas distribution system to replace natural gas.
    - 2027 – continue from 2026 with the goal to advance one opportunity to definitive agreement.
- **Production Supply Opportunities:**
    - 2026 – continue feasibility evaluation of 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.
    - 2027 – continue progress from 2026 to advance identified project opportunities.

[42] Canadian Pacific (CP) and Kansas City Southern (KC).

- **Hydrogen Distribution and Customer End-Use Service (Gas System Hydrogen Readiness Assessment and Conversion):**
  - 2026 – FEI has been working with a consultant on a study to determine the overall requirements to distribute hydrogen blended into the natural 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. The project will conclude in 2026.
- **Concurrent Hydrogen Development Enabling Initiatives:**
  - 2026 and 2027 – Continue progressing various concurrent activities including workforce education and training initiatives, engaging with technical regulators in BC, Canadian Standards Association (CSA), NRCan, and various other authorities having jurisdiction regarding various initiatives on hydrogen safety, codes and standards.
- **Hydrogen Demonstration Pilot Projects:**
  - 2026 and 2027 – continue detailed feasibility and project development for hydrogen blending projects that would blend hydrogen into a relatively small, isolated section of FEI's distribution system (e.g., FEI's Surrey Education Centre) and within customer sites.
- **Hydrogen Development Study:**
  - 2026 – This study will assess the practical requirements for deploying hydrogen fuel cell Class 8 trucks with a large fleet partner in BC. The work will evaluate suitable deployment lanes and use cases, expected hydrogen demand, vehicle integration requirements, fuelling infrastructure needs, hydrogen supply options, cost competitiveness, reliability risks, and phased rollout requirements. The study will support FEI's assessment of future hydrogen transportation demand, infrastructure requirements, supply planning, and potential implementation pathways.
- **CPKC Rail Feasibility Study:**
  - 2027 – This study will assess hydrogen fuelling options for CPKC's switch locomotive operations yard in Pitt Meadows and define the technical, siting, permitting, infrastructure, and hydrogen supply requirements needed to support a potential pilot or phased deployment. The study will evaluate whether rail operations could provide a high-throughput anchor load to support development of a broader hydrogen hub.

6.3.8 Clean Growth Initiative – NGT O&M

NGT O&M is comprised of O&M expenses related to the operation of the FEI-owned CNG and LNG fuelling stations as well as FEI-owned LNG tankers available for rental to LNG customers. Table 6-10 below summarizes the NGT O&M for 2026 Approved, 2026 Projected, and 2027 Forecast.

Table 6-10: NGT O&M ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	CNG Stations	$ 1.979	$ 1.920	$ 2.141
2	LNG Stations	0.265	0.265	0.260
3	LNG Tankers	0.680	0.680	0.710
4	Emergency Response and Preparedness (ERAP)	0.070	0.070	0.110
5	Total NGT O&M	$ 2.994	$ 2.934	$ 3.221

The 2026 Projected NGT O&M is consistent with the 2026 Approved amount.

The 2027 Forecast NGT O&M is $0.287 million higher than 2026 Projected, mainly due to a $0.221 million increase in CNG Stations O&M costs associated with planned overhauls and rebuilds at several CNG stations. In addition, FEI is forecasting increases in LNG tanker and ERAP O&M costs due to increased maintenance requirements for aging tankers.

6.3.9 Clean Growth Initiative – Variable LNG Production Costs

LNG O&M costs are allocated between formula and forecast (flow-through) O&M based on whether they are fixed or variable costs. Fixed costs represent the costs to operate the LNG plant, regardless of its use (for peak shaving storage, or LNG production for sales) while the variable costs include the liquefaction of natural gas, the dispensing of LNG, and the handling and loading of tankers with LNG which tend to fluctuate and are dependent on sales volumes.

Table 6-11 below summarizes the various components of the Variable LNG Production Costs for 2026 Approved, 2026 Projected, and 2027 Forecast.

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

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Tilbury LNG Facility:			
2	Labour	$ 3.253	$ 4.283	$ 4.455
3	Materials	0.878	1.078	1.121
4	Contractor	0.361	0.361	0.376
5	Power	5.267	6.267	6.518
6	Fees and Employee Expenses	0.212	0.212	0.220
7	Sub-total	$ 9.971	$ 12.201	$ 12.690
8	Mt. Hayes LNG Facility:			
9	Labour	$ 0.409	$ 0.372	$ 0.387
10	Materials	0.199	0.184	0.191
11	Contractor	0.204	0.261	0.450
12	Power	0.244	0.231	0.240
13	Fees and Employee Expenses	0.010	0.010	0.011
14	Sub-total	$ 1.067	$ 1.058	$ 1.279
15	Total O&M	$ 11.038	$ 13.260	$ 13.969

The Variable LNG Production O&M expense required for operation of the expanded Tilbury LNG facility[43] and the Mt. Hayes LNG facility consists of labour (includes LNG operators for truck loading and shunting of LNG, millwrights and electrical and instrumentation technicians to support production-related maintenance activities as well as operations management), materials, contractors (for truck loading and support of production related activities), power (includes electricity costs and consumables), and administration fees and employee expenses.

Tilbury LNG Facility

FEI discusses the 2026 Projected and 2027 Forecast variable costs below.

- **Labour:** 2026 Projected is expected to be higher than 2026 Approved due to increased LNG sales demand under RS 46, as discussed in Section 3.2.4 of the Application, necessitating additional support. The 2027 Forecast is expected to be relatively consistent with 2026 Projected, with an adjustment for inflation, given the relatively consistent forecast of LNG sales as discussed in Section 3.2.4.
- **Materials:** 2026 Projected is expected to be higher than 2026 Approved primarily due to more liquefaction runs requiring additional refrigerants to support the increased LNG sales demand. The 2027 Forecast is expected to be at a level similar to 2026 Projected, with an adjustment for inflation, given the relatively consistent forecast of LNG sales.

[43] The expanded LNG facility includes the Phase 1A facilities defined in Direction No. 5 to the BCUC, B.C. Reg. 245/2013, as amended by B.C. Reg. 265/2014.

- **Contractors:** The 2026 Projected O&M is expected to be consistent with 2026 Approved. For 2027, FEI expects that contractor costs will be consistent with 2026, with a slight increase due to inflation.
- **Power:** 2026 Projected is expected to be higher than 2026 Approved due to increased LNG sales demand under RS 46. The 2027 Forecast is expected to be in line with 2026 Projected, plus an increase of 4 percent to account for increased electricity rates.
- **Fees and Employee Expenses:** The 2026 Projected O&M is expected to be consistent with 2026 Approved. For 2027, FEI is forecasting a slight increase due to inflation.

Mt. Hayes LNG Facility

As shown in Table 6-11 above, the Mt. Hayes LNG Facility's O&M is a small component of the total Variable LNG Production O&M.

The primary drivers of the projected/forecast increases in 2026 and 2027 are inflation, overhaul compressor work (which has resulted in an increase in contractor costs for 2027), annual salary increases, and BC Hydro rate changes.

6.4 *NET O&M EXPENSE*

Net O&M expense is gross O&M less capitalized overhead and RNG O&M transferred to the RNG Account. As approved in the RSF Decision, the capitalized overhead rate is set at 14.5 percent for FEI. After capitalized overhead and the transfer of the RNG O&M to the RNG Account, the net O&M expense for 2027 is $353.027 million.

6.5 *SUMMARY*

Overall, the increase in gross O&M expense from 2026 Approved to 2027 Forecast is 1.9 percent, with approximately 1.2 percent out of the 1.9 percent attributable to the increase in formula O&M and the remaining 0.7 percent attributable to an increase in the O&M forecast outside of the formula.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

Rate base is comprised of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, and deferred income tax.

FEI's 2027 Forecast rate base is $7.539 billion. It includes the full-year impact of the 2026 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $355.126 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $255.666 million;
- Major projects capital additions, net of CIAC, of $1.034 billion as discussed in Section 7.4, which include:
  - Full-year impact of $59.699 million of capital expenditures and related AFUDC for the ITS TIMC CPCN Project;
  - Full-year impact of $221.354 million of capital expenditures and related AFUDC for the AMI CPCN Project;
  - Full-year impact of $0.200 million of capital expenditures and related AFUDC for the Okanagan Capacity Mitigation Plan (OCMP) CPCN Project;
  - Full-year impact of $2.738 million for the Tilbury 1A/1B Expansion Project; and
  - Three-month impact of $750.000 million of capital expenditures, net of CIAC and related AFUDC for the Eagle Mountain – Woodfibre Gas Pipeline (EGP) Project.

In addition, various changes in deferred charges, working capital and other items are forecast to increase rate base by a net amount of $179.706 million in 2027.

Details of the 2027 Forecast plant balances as well as depreciation, retirements, CIAC, working capital, and other rate base items are provided in Section 11.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the RSF Decision, FEI received the following approvals for regular capital expenditures:

- Growth capital to be set annually on a formula basis for the term of the RSF;
- Three-year forecasts of Sustainment and Other capital expenditures; and
- Flow-through capital for several items to be forecast on an annual basis.

The components of FEI's 2027 regular capital expenditures are shown in Table 7-1 below.

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

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast	Reference
1	Formula Growth Capex	$ 71.505	$ 71.505	$ 104.381	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	194.429	194.429	186.697	Section 11, Schedule 4, Line 16 + 17
3	Flow through Capex	5.895	9.885	17.041	Section 11, Schedule 4, Sum of Line 13 to 15
4	Total Gross Regular Capex	$ 271.829	$ 275.819	$ 308.119	Sum of Lines 1 to 3; Section 11, Schedule 4, Line 20
5	Less: Formula CIAC	(2.885)	(2.885)	(1.520)	Section 11, Schedule 9, Line 2
6	Less: Forecast CIAC	(8.443)	(8.443)	(6.067)	Section 11, Schedule 9, Line 3 to 5
7	Net Regular Capex	$ 260.501	$ 264.491	$ 300.532	Sum of Lines 4 to 6

In the subsections below, FEI provides further details on its regular capital expenditures for 2027.

7.2.1 Formula Growth Capital Expenditures

The formula-driven Growth capital expenditures are calculated based on the prior year's approved Unit Cost for Growth Capital (UCGC), escalated by the I-Factor less an X-Factor of 0.55 percent, and multiplied by the forecast Gross Customer Additions (GCA), resulting in the forecast inflation-indexed Growth capital before the true-up of actual GCA from two years prior, the formulaic CIAC, and the forecast for the System Extension Fund (SEF).[44]

The formula Growth capital is calculated as follows:

2026 Base UCGC x [1 + (2027 I-Factor – 2027 X-Factor)] x 2027 Forecast GCA + 2025 Formula Growth Capital True-up + 2027 Formula CIAC + 2027 Forecast SEF

Table 7-2 below shows the calculation of the resulting 2027 Formula Growth capital expenditures.

[44] Pursuant to Order G-338-20, the SEF is approved to be up to $1 million per year.

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

Line No.	Description	2027 Forecast	Reference
1	Prior Year Base Unit Cost Growth Capital	$ 9,893	G-69-25 and Section 11, Sch 4, Line 2
2	Net Inflation Factor	1.901%	Section 11, Schedule 3, Line 9
3	Current Year Unit Cost Growth Capital	$ 10,081	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast	8,800	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	$ 88.713	Line 3 x Line 4 / 1,000,000
6	Gross Capital True-up	13.148	Line 16
7	Formulaic CIAC	1.520	Section 11, Schedule 9, Line 2
8	System Extension Fund	1.000	G-338-20 SEF Decision
9	Gross Formula Growth Capex	$ 104.381	Sum of Lines 5 through 8
10			
11	Gross Capital True-up		
12	2025 Actual Gross Customer Addition	11,364	Section 2, Table 2-3
13	2025 Forecast Gross Customer Addition	10,000	G-287-25 2025-2026 Annual Review
14	Difference	1,364	Line 12 - 13
15	2025 Unit Cost Growth Capital ($/customer)	$ 9,639	G-287-25 2025-2026 Annual Review
16	Growth Capital True-up in 2025	$ 13.148	Line 14 x Line 15 / 1,000,000

The 2027 Gross Formula Growth capital amount is $104.381 million. This amount includes the 2025 Growth capital true-up of $13.148 million, the formulaic CIAC amount of $1.520 million, and the forecast SEF amount of $1.000 million.

7.2.2 Forecast Capital Expenditures

The level of forecast capital expenditures approved for 2027 by the RSF Decision is shown in Table 7-3 below. The 2026 Approved and 2026 Projected are also shown for informational purposes.

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

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast	Reference
1	Sustainment Capital	$ 131.733	$ 131.733	$ 125.484	Section 11, Schedule 4, Line 16
2	Other Capital	62.696	62.696	61.213	Section 11, Schedule 4, Line 17
3	Total	$ 194.429	$ 194.429	$ 186.697	Line 1 + 2

7.2.3 Flow-Through Capital Expenditures

In addition to FEI's formula Growth capital and forecast Sustainment and Other capital, FEI is approved flow-through treatment for a number of capital items, including pension and OPEB expense related to Growth capital, capital expenditures related to Clean Growth Initiatives (which currently include capital expenditures related to RNG and NGT), and exogenous factors (if applicable). These amounts are shown in Table 7-4 below along with a comparison to 2026.

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

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast	Reference
1	Pension/OPEB (Growth Capital Portion)	$ 1.095	$ 1.095	$ 1.012	Section 11, Schedule 4, Line 13
2	RNG Capital Expenditures	4.800	1.149	16.029	Section 11, Schedule 4, Line 14
3	NGT Capital Expenditures	-	7.641	-	Section 11, Schedule 4, Line 15
4	Total	$ 5.895	$ 9.885	$ 17.041	Sum of Lines 1 through 3

Each of these items is discussed further below. The cost of service impact due to variances in pension and OPEB expenditures is captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-138-14. The cost of service impact due to variances in Clean Growth Initiatives and exogenous factors (if applicable) are captured in the Flow-through deferral account.

7.2.3.1 Pension/OPEB (Growth Capital Portion)

The 2027 Forecast Growth capital portion of the total pension and OPEB costs are $1.012 million. Please refer to Section 6.3.1 for details on the pension and OPEB costs.

7.2.3.2 RNG Capital Expenditures

Table 7-5 below provides the 2026 Approved, 2026 Projected and 2027 Forecast for RNG capital expenditures, including references to the BCUC order approving each project.

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

Line No.	Description	BCUC Order	2026 Approved	2026 Projected	2027 Forecast
1	Kelowna	E-19-12	$ -	$ 0.413	$ 0.500
2	REN Energy	G-60-20	-	-	-
3	Foothills LF (RDFFG)	E-2-22	3.000	-	-
4	Dickland Farms	E-13-20	-	0.020	-
5	Capital Regional District	E-15-21	-	0.032	-
6	City of Vancouver	G-235-19	-	-	-
7	Net Zero Waste	E-21-21	-	-	-
8	Delta RNG (MAS Energy)	E-3-22	-	0.027	4.000
9	Seabreeze Farm	E-11-19	0.100	0.085	0.060
10	Lulu Island	E-16-21	0.100	0.038	0.060
11	City of Surrey	E-3-16	0.100	0.020	0.060
12	Fraser Valley Biogas Expansion	E-27-24	0.500	0.289	0.200
13	Salmon Arm Upgrader	G-235-19	-	0.225	0.050
14	Comox Valley LF	Signed, to be filed	1.000	-	11.099
15	Total RNG CAPEX		$ 4.800	$ 1.149	$ 16.029

FEI's applications for each RNG project are filed and accepted individually by the BCUC; therefore, the capital estimates provided in the Annual Review are for information purposes as they reflect the current projected and forecast estimates for RNG capital expenditures in customer rates.

The 2026 Projected capital expenditures are $3.651 million lower than 2026 Approved. The decrease is primarily due to delays in both the Foothills Landfill (RDFFG) project and Comox Valley Landfill (LF) biogas plant project. These decreases are partially offset by the addition of $0.413 million of projected capital expenditures in 2026 for the Kelowna project. FEI is expecting to complete three sustainment projects at the Kelowna facility to improve safety and operational flexibility at the facility and to increase the volatile organic compound storage capacity of the facility.

The 2027 Forecast of $16.029 million is primarily related to capital expenditures for the Comox Valley LF project, the Delta RNG (MAS Energy) project, and the Kelowna project (as described above). The Comox Valley LF project involves constructing a connection to the existing landfill gas collection system. The facilities will include a biogas upgrading plant, an interconnection pipeline, and an interconnection station connecting to FEI's natural gas distribution system. The project is expected to be in-service by 2028. The Delta RNG (MAS Energy) project capital expenditures are related to improvements to the distribution pipeline and control valve.

7.2.3.3 NGT Capital Expenditures

Table 7-6 provides additional details by project for the 2026 and 2027 NGT capital expenditures.

Table 7-6: NGT Capital Expenditures ($ millions)

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Tilbury Truck Load-out Project	$ -	$ 7.641	$ -

The 2026 Projected capital expenditures are all attributable to the Tilbury truck load-out project, as discussed in previous Annual Reviews.

As discussed in the Annual Review for 2025 and 2026 Delivery Rates, the project was delayed as a result of the contractor filing for bankruptcy protection part way through the execution of the project (in April 2023). FEI had anticipated completing the remainder of the project in 2025; however, due to the timing of the insurance claim being settled and recovered, FEI is now expecting to complete the remainder of the project before the end of 2026.

7.3 *MAJOR PROJECTS CAPITAL EXPENDITURES*

Major projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application, or are projects that are proceeding as a result of an Order in Council (OIC). As part of the RSF Decision, the BCUC approved the continuation of the current process of reviewing major projects outside of the RSF and approved the continuation of the existing financial threshold for CPCNs of $15 million for FEI for the RSF term.[45]

[45] RSF Decision and Order G-69-25, pp. 15-18.

In 2027, FEI is forecasting capital expenditures related to the following approved major projects:

- ITS TIMC CPCN Project;
- AMI CPCN Project;
- OCMP CPCN Project;
- Tilbury 1A/1B Expansion Project;
- CTS Expansion Project;
- Tilbury LNG Storage Expansion (TLSE) CPCN Project;
- Enterprise Resource Planning (ERP) Modernization Project; and
- EGP Project.

Each project is discussed below.

7.3.1 ITS TIMC CPCN Project

The ITS TIMC Project CPCN application was filed with the BCUC in September 2022 and approved by Order C-1-24. The project consists of the replacement of three heavy wall pipeline segments on two of the ITS pipelines, and modification to 13 transmission pressure facilities within the ITS that are necessary to ready the pipelines for EMAT ILI tools.

The ITS TIMC Project is scheduled to conclude in-field construction by the end of November 2026, with approximately $59.699 million expected to enter rate base on January 1, 2027.[46] FEI is forecasting to complete the remaining closeout and turnover costs, estimated to be $0.555 million, in Q2 2027.

7.3.2 AMI CPCN Project

The AMI Project CPCN application was filed with the BCUC in May 2021 and was approved by Order C-2-23. The AMI Project involves installation of approximately 1 million residential, commercial, and industrial advanced gas meters and meter retrofits of communication modules capable of remote gas consumption measurement. The project also includes installation of approximately 1,100 communication modules on FEI's gas network as well as installation of the AMI network and infrastructure for communication with the AMI meters.

The network installation is well underway and is expected to be completed in 2026. Mass deployment of meters started in March 2025, utilizing four deployment contractors located across

[46] Approximately $42.341 million already entered rate base on January 1, 2026.

the service territory along with FEI Operations. Mass deployment is progressing as planned and will continue through to Q2 2028.

FEI is forecasting capital expenditures of $207.829 million in 2027 (excluding AFUDC) for the AMI Project, with $221.354 million expected to be added to rate base on January 1, 2027.

7.3.3 OCMP CPCN Project

The OCMP Project CPCN application was filed with the BCUC on July 30, 2024 and approved by Order C-2-25. The project involves a small-scale LNG facility in Kelowna to address the capacity requirements in the Okanagan region. The project will be executed over a three-year period from 2025 to 2027.

FEI is forecasting capital expenditures of $5.523 million in 2027 (excluding AFUDC) related to the engineering and design work as well as installation of the virtual pipeline interfacing equipment. FEI is forecasting approximately $0.200 million including AFUDC to enter rate base on January 1, 2027.

7.3.4 Tilbury 1A/1B Expansion Project

The cost recovery of expenditures associated with the Tilbury 1A/1B Expansion Project is authorized by Direction No. 5 to the BCUC as amended by OIC No. 557 (2013), 749 (2014), and 162 (2017). Under Direction No. 5, FEI can spend up to $425 million and $400 million in capital costs for Tilbury 1A and 1B, respectively, plus AFUDC and feasibility and development costs, to construct storage and liquefaction facilities at Tilbury Island. The Tilbury 1A expansion has been in-service since 2018, while the Tilbury 1B expansion is expected to be completed in multiple stages.

FEI forecasts capital expenditures of $138.738 million in 2027 (excluding AFUDC) related to development and capital costs for Tilbury 1B. Additionally, FEI is forecasting approximately $2.738 million (including AFUDC) of capital additions related to Tilbury 1A which will enter rate base on January 1, 2027.

7.3.5 CTS Expansion Project

The CTS Expansion Project at and between the Tilbury Gate Station and the Tilbury LNG Facility is authorized by Direction No. 5 to the BCUC as amended by OIC No. 557 (2013), 749 (2014), and 162 (2017). The project involves the design and installation of a new 1.5 km bi-directional 30” pipeline to the Tilbury LNG Plant as well as facility modifications to tie-in both ends of the pipeline. FEI is currently advancing engineering and developing an AACE Class 3 cost estimate and schedule for execution. The project will advance into detailed design later this year with construction planned to begin in late 2027.

FEI is forecasting capital expenditures of $20.000 million in 2027 (excluding AFUDC) with no capital additions to rate base forecast until 2029.

7.3.6 TLSE CPCN Project

The TLSE CPCN Project was approved on October 27, 2025 by Order C-6-25. The project entails replacing the 50-year-old Tilbury Base Plant with a new 3 Bcf LNG storage tank and 800 MMcf/day of regasification capacity. The total forecast cost including AFUDC is $1.141 billion, and the project is expected to enter rate base in 2030.

The TLSE Project is part of the Tilbury Phase 2 Expansion, which is currently in the late stages of a joint federal-provincial environmental assessment (EA) process. FEI submitted an Initial Project Description in February 2020, commencing the EA process. The Tilbury Phase 2 Expansion project will be referred to the Ministers for a decision at the end of the effects assessment phase, which is scheduled to conclude in August 2026. FEI expects a ministerial decision to be issued in the fourth quarter of 2026. Subject to the receipt of a positive decision, FEI will proceed with the development of the condition management plans required to satisfy the conditions of the Environmental Assessment Certificate.

FEI forecasts capital expenditures of $28.200 million in 2027 (excluding AFUDC) with no capital additions to rate base forecast until 2030.

7.3.7 ERP Modernization Project

The ERP Modernization Project was approved by Order G-125-26 and involves upgrading the existing core SAP applications to SAP S/4HANA. The total forecast capital cost for the ERP Modernization Project is approximately $92.2 million, including AFUDC.

FEI forecasts capital expenditures of $48.842 million (excluding AFUDC) in 2027. The ERP Modernization Project is expected to be complete in 2028 with no capital additions to rate base until January 1, 2029.

7.3.8 EGP Project

The EGP Project entails extending the existing Vancouver Island Transmission System (VITS) and completing compressor station upgrades, including construction of approximately 47 km of natural gas pipeline and associated infrastructure. The pipeline will generally parallel FEI's existing Vancouver Island pipeline from the existing Eagle Mountain Compressor Station in Coquitlam, BC to the Woodfibre LNG plant site on the northwestern shore of Howe Sound. The pipeline will provide natural gas to the new Woodfibre LNG facility.

FEI is forecasting capital expenditures of $265 million (excluding AFUDC) in 2027. FEI is expecting the EGP Project to complete in Q3 2027, with total capital additions of $750 million, net of CIAC, to be added to rate base on October 1, 2027.

7.4 *2027 PLANT ADDITIONS*

The 2027 plant additions are comprised of: (i) FEI's 2027 regular capital expenditures; (ii) the change in work in progress which adjusts for capital expenditures for projects that are still in progress at year end; (iii) AFUDC; (iv) overhead capitalized for the year; and (v) the additions from major projects on January 1, 2027. A reconciliation of capital expenditures to plant additions is shown in Table 7-7 below and is also provided in Section 11, Schedule 5 (for capital expenditures) and Schedule 9 (for CIAC additions).

Table 7-7: Reconciliation of 2027 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description		2027 Forecast	Reference
1	Formula Growth Capex	$	104.381	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex		186.697	Section 11, Schedule 4, Line 16 + Line 17
3	Flow through Capex		17.041	Section 11, Schedule 4, Sum of Line 13 to 15
4	Total Gross Regular Capex	$	308.119	Sum of Lines 1 to 3
5	Capitalized Overheads		61.393	Section 11, Schedule 5, Line 23
6	AFUDC		4.300	Section 11, Schedule 5, Line 24
7	Change in Work in Progress		(11.099)	Section 11, Schedule 5, Line 26
8	Less CIAC Additions		(7.587)	Section 11, Schedule 9, Line 6, Col. 5
9	Total Regular Additions to Plant, net of CIAC	$	355.127	Sum of Lines 4 to 8
10				
11	Special Projects and CPCN Capex			
12	ITS Transmission Integrity Program	$	0.555	Section 11, Schedule 5, Line 7
13	Advance Metering Infrastructure (AMI)		207.829	Section 11, Schedule 5, Line 8
14	Okanagan Capacity Mitigation Plan (OCMP)		5.523	Section 11, Schedule 5, Line 9
15	Tilbury Expansion Project		138.738	Section 11, Schedule 5, Line 10
16	CTS Expansion Project		20.000	Section 11, Schedule 5, Line 11
17	Tilbury LNG Storage Expansion (TLSE)		28.200	Section 11, Schedule 5, Line 12
18	ERP Modernization Project		48.842	Section 11, Schedule 5, Line 13
19	Eagle Mountain-Woodfibre Gas Pipeline Project (EGP)		264.997	Section 11, Schedule 5, Line 14 - Schedule 9, Line 3, Col. 3
20	Subtotal, net of CIAC	$	714.684	Sum of Lines 12 to 19
21	AFUDC		38.989	Section 11, Schedule 5, Line 30
22	Change in Work in Progress		280.319	Section 11, Schedule 5, Line 32
23	Total Special Projects and CPCN Additions to Plant, net of CIAC	$	1,033.992	Sum of Lines 20 to 22
24				
25	Total Additions to Plant, net of CIAC	$	1,389.119	Sum of Lines 9 and 23

7.5 *ACCUMULATED DEPRECIATION*

FEI's rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

The depreciation rates used for 2027 were approved in the RSF Decision and are based on FEI's most recent depreciation study. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-138-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance net of CIAC, the 2027 depreciation expense is calculated as $249.179 million.[47]

[47] $257.352 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $8.173 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

7.6 DEFERRED CHARGES

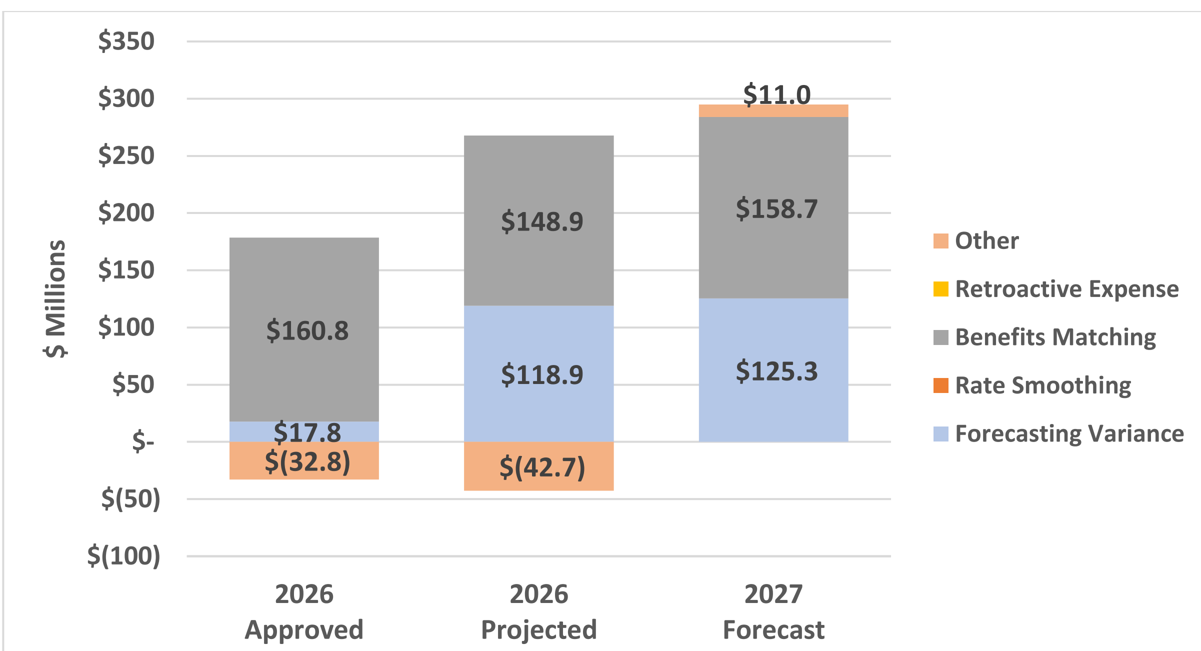
On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[48] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedules 11 and 11.1, FEI has classified its existing rate base deferral accounts in accordance with this classification.

Figure 7-1 below provides the mid-year deferral account balances for 2026 Approved, 2026 Projected and 2027 Forecast summarized by deferral account category.

For 2027, FEI is forecasting a mid-year balance of unamortized deferred charges in rate base to be a debit of $294.969 million, which is an increase of $69.815 million from the 2026 Projected level. The largest driver of the increase in the 2027 Forecast balance is the DSM deferral account. Other deferral accounts contributing to the increase are the Commodity Cost Reconciliation Account (CCRA), as well as the Existing Meter Cost Recovery Account and the Previously Retired Meter Cost Recovery Account, both of which were approved as part of the AMI Project CPCN Decision and Order C-2-23. The increases from these accounts are partially offset by the reduced forecast balance of the RSAM account as well as the Net Salvage Provision deferral account.

Figure 7-1: FEI Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



48 Log No. 53608, Appendix B.

Based on the approved amortization of each deferral account, the amortization expense including both rate base and non-rate base deferral accounts for 2027 to be recovered as part of the proposed delivery margin is $170.848 million.[49] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FEI is seeking approval of three new rate base deferral accounts to capture costs associated with the regulatory processes for the following applications:

- 2028+ Rate Setting Application;
- 2026 Long-Term Gas Resource Plan (2026 LTGRP); and
- 2026 MX Policies Review.

Table 7-8 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to the deferral accounts requested in Section 7.6.1.1 to 7.6.1.3 below.

Table 7-8: Deferral Account Filing Considerations

Item	Consideration	Determination
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	FEI requests the establishment of three new deferral accounts to capture costs related to the regulatory process for the 2028+ Rate Setting Application, 2026 LTGRP and the 2026 MX Policies Review. Please refer to Sections 7.6.1.1 to 7.6.1.3 for additional information.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.
II.	Propose a term (i.e., length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.

[49] Section 11, Schedule 21, Column 3, Sum of Lines 8 to 10.

Item	Consideration	Determination
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the RSF formula O&M since regulatory proceeding costs are not included in Base O&M expense) and trued up annually by way of the Flow-through deferral account. FEI considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the BCUC and the degree of involvement of interveners.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FEI forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the RSF. See Sections 7.6.1.1 to 7.6.1.3.
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. See Sections 7.6.1.1 to 7.6.1.3. There are no intergenerational inequities inherent in this practice.
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 classifies these 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.

Item	Consideration	Determination
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.
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 assistance 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.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally, FEI amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. See Sections 7.6.1.1 to 7.6.1.3.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral accounts can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirements proceedings.

7.6.1.1 2028+ Rate Setting Application

The currently approved rate-setting framework will end in 2027. FEI has commenced development of its next rate setting plan and anticipates filing it with the BCUC in 2027. FEI will incur regulatory costs related to the development of the application and is requesting approval to establish a rate base deferral account to capture these costs, which will include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs.

FEI forecasts costs of $0.020 million ($0.015 million after-tax) in 2026 and $0.540 million ($0.394 million after-tax) in 2027. Actual costs will vary depending on how the application progresses and will be confirmed after the regulatory process is completed.

FEI is only requesting approval to establish this deferral account in this Application. FEI will propose an amortization period for the deferral account in a future rate-setting application.

7.6.1.2 2026 LTGRP

As directed in Order G-78-24, FEI filed its 2026 LTGRP on March 27, 2026. FEI is seeking approval to establish a rate base deferral account to record the regulatory costs associated with the development and regulatory review of the 2026 LTGRP. FEI is also seeking approval to amortize the 2026 LTGRP deferral account over three years, commencing January 1, 2027. FEI believes a three-year amortization period is appropriate as it is consistent with the recovery period approved for past LTGRP proceeding cost deferral accounts (e.g., the 2022 LTGRP deferral account).

The scope, complexity, and analytical depth of the 2026 LTGRP have increased relative to previous filings, particularly in areas such as demand forecasting methodologies, DSM evaluation, greenhouse gas emissions analysis, and long-term energy transition considerations. As a result, additional analytical rigor, modelling enhancements, and engagement activities have been required to support the development of the 2026 LTGRP.

FEI is forecasting total costs for the 2026 LTGRP of $2.900 million. These costs include studies/analysis, multiple external consultants, engagement costs, and regulatory proceeding costs (i.e., external legal fees, participant funding costs, BCUC costs, and public notification costs). Table 7-9 below provides a breakdown of the total estimated costs for the 2026 LTGRP application. Of the total estimate of $2.900 million, approximately $2.268 million ($1.656 million after tax) has been incurred to date, as these costs relate to the studies/analysis performed (including the work performed by external consultants) and the engagement activities undertaken as part of the development of the 2026 LTGRP.

Table 7-9: 2026 LTGRP Estimated Expenditures

Activity	$ millions
Long-term demand forecasting scenario modelling, and DSM analysis	1.650
RPAG, interested parties, and Indigenous communities' engagement	0.250
Dual-Fuel analysis	0.500
Regulatory proceeding costs	0.500
Total	**2.900**

7.6.1.3 2026 MX Policies Review

On May 15, 2016, pursuant to Letters L-11-25 and L-24-25, FEI filed its 2026 Main Extensions and Connection Policies Review, which contains a review of its terms and conditions, extension policies and the parts of the tariff governing customer connections.

As part of this review, FEI expects to incur approximately $0.333 million ($0.243 million after tax) in 2026 for costs related to legal fees, BCUC costs, stakeholder consultation costs, and participant funding costs. FEI is seeking approval to capture these costs in a rate base deferral account and to amortize these costs over a one-year period beginning January 1, 2027. Any variance between the forecast account balances and the actual costs incurred will be amortized into rates in the following year.

7.6.2 Existing Deferral Accounts

FEI is not seeking modification of any existing rate base deferral accounts in this Application.

7.7 *WORKING CAPITAL*

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved by the RSF Decision.

Other working capital includes gas in storage, transmission line pack gas, inventory of materials and supplies, employee loans and withholdings and refundable contributions.

The main components of other working capital are gas in storage and transmission line pack, which are forecast on a 13-month average basis using the approved costs embedded in the Q2 2026 gas cost report and historical volumes. All other 2027 amounts are forecast based on 2025 Actual levels.

7.8 *SUMMARY*

FEI's rate base includes the impact of formula-driven Growth capital expenditures, regular forecast Sustainment and Other capital expenditures, flow-through capital expenditures and major projects, adjusted for work-in-progress, AFUDC and overheads capitalized. FEI has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.6.1, FEI is requesting three new rate base deferral accounts to record the costs associated with regulatory applications. Finally, the rate base includes other working capital, comprised of gas in storage and other smaller components that have been forecast consistent with prior years.

8. FINANCING AND RETURN ON EQUITY

8.1 *INTRODUCTION AND OVERVIEW*

FEI has prepared this Application using the benchmark capital structure of 55 percent debt and 45 percent equity and a Return on Equity (ROE) of 9.65 percent, as approved by Order G-236-23.

The 2027 Forecast for financing costs, including the interest expense on issued long-term and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FEI's AFUDC rate for 2027 (which is equal to FEI's after-tax weighted average cost of capital) is 6.24 percent. Any variances from interest rates used to set delivery rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 *CAPITAL STRUCTURE AND RETURN ON EQUITY*

FEI finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Pursuant to Order G-236-23, the BCUC approved a benchmark capital structure of 55 percent debt and 45 percent equity with an allowed ROE of 9.65 percent, effective January 1, 2023, which have been used to calculate rates in this Application.

8.3 *FINANCING COSTS*

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long-term and short-term debt.

8.3.1 Long-Term Debt

FEI is both a private and public issuer of long-term debt. FEI plans to issue long-term debt of approximately $400 million[50] in 2026 and approximately $600 million in 2027. FEI will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. Both the 2026 and 2027 debt issuances are reflected in the financial schedules at a rate of 4.90 percent.[51] The exact timing, amount and rate of the issuance will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of debt or the rates at which they are issued are captured in the Flow-through deferral account.

[50] Only approximately $392 million of which is financing FEI's rate base in 2026 as the remainder finances the non-rate base Lower Mainland Acquisition Premium.

[51] Section 11, Schedule 27, Lines 20 to 21 (effective rate of 4.964 percent net of amortized debt issue costs).

8.3.2 Short-Term Debt

FEI obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the commercial paper issuances by maintaining a $900 million committed credit facility that matures in July 2031. The credit facility provides FEI with short-term liquidity to fund its capital program and working capital requirements. FEI also maintains a letter of credit facility that matures in March 2027 to support its letters of credit. In 2026, the letter of credit facility was reduced from $55 million to $40 million.

8.3.3 Forecast of Interest Rates

FEI uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FEI are maintained.

FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian benchmark rate and the rate obtained by FEI under its commercial paper program. Canada has now fully discontinued the Canadian Deposit Overnight Rate (CDOR) as a benchmark for financial instruments, with the last publication date being June 28, 2024. The Term Canadian Overnight Repo Rate Average (CORRA) has replaced CDOR as the risk-free interest rate benchmark for one-month and three-month loan terms. For the purposes of forecasting the short-term interest rate for 2027, a 3-year average approach was taken to factor in both CDOR through June 28, 2024, and CORRA post-June 28, 2024.

CORRA (previously CDOR) is used because FEI's short-term borrowings under its credit facility are priced based on CORRA (previously CDOR) and therefore CORRA (previously CDOR) is tracked relative to FEI's commercial paper borrowings. As both CORRA and CDOR are not forecast by economists, FEI must first obtain the 3-month T-Bill rate forecast and then convert it to a CORRA/CDOR forecast. FEI does this by taking the 3-year historical spread between CORRA/CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FEI adjusts the CORRA/CDOR forecast with the 3-year historical spread between CORRA/CDOR and rates of issuances under its commercial paper program.

The short-term borrowing rate forecast for 2027 is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FEI Short Term Interest Rate	2026 Approved	2026 Projected	2027 Forecast
3-Month T-Bill Rate[1]	2.20%	2.30%	2.70%
Spread to CORRA	0.44%	0.39%	0.39%
CORRA Rate	2.64%	2.69%	3.09%
Spread to CP	-0.36%	-0.44%	-0.44%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facility	2.38%	2.35%	2.75%
Fixed Financing Fees			
Stanby fee on Undrawn Credit[2]	0.72%	0.72%	0.72%
Renewal Fee[3]	0.16%	0.14%	0.14%
Other Financing Fees[4]	0.12%	0.12%	0.12%
ST Interest Rate on Fixed Financing Fee	1.00%	0.97%	0.97%
FEI Short Term Rate	3.38%	3.32%	3.72%

Notes to table:

1 The 3-month T-Bill rate for 2027 is an average rate based on forecasts provided by Canadian Chartered banks in July 2026.

2 The forecast assumes FEI will borrow through commercial paper and a standby fee of 16 bps is charged on undrawn credit facility amounts. The fee has been converted into a short-term rate for forecast purposes.

3 The renewal fee is paid to extend the maturity date of the credit facility and is charged on the principal amount of $900 million. The renewal fee is paid regardless of whether FEI draws from the credit facility. The fee has been converted into a short-term rate for forecast purposes.

4 Other financing fees include commercial paper issuance fees, letter of credit fees and miscellaneous bank administration costs. These fees are incurred regardless of whether FEI draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

As shown in Table 8-1 above, the short-term borrowing rates for 2026 Projected and 2027 Forecast are 3.32 percent and 3.72 percent, respectively. The short-term rate is comprised of the short-term interest rate on FEI's credit facility and the short-term interest rate on fixed financing fees. The 2027 Forecast rate is higher than the 2026 Projected and 2026 Approved rates primarily due to a higher forecast 3-Month T-Bill rate. The higher forecast 3-Month T-Bill rate reflects changes in market expectations for the future path of the Bank of Canada policy rate, which is the primary driver of short-term yields.

The short-term interest rate on fixed financing fees for 2027 is consistent with the 2026 Projected rate.

8.3.4 Forecast of Interest Expense

The interest expense forecast reflects FEI's existing and forecast borrowing costs on long-term and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the effective interest method. For each long-term debt issue, the effective rate (forecast effective rate if it is a new issue) is multiplied by the average balance of that long-term debt for the year. The 2027 long-term debt schedule is provided in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FEI applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FEI's AFUDC rate for 2027 (which is equal to its after-tax weighted average cost of capital) is 6.24 percent. The calculation of the rate is provided in the following table.

Table 8-2: Calculation of AFUDC Rate for 2027

	2027			
	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	1.42%	3.72%	2.72%	3.72%
Long Term Debt	53.58%	4.74%	3.46%	4.74%
Common Equity	45.00%	13.22%	9.65%	9.65%
Weighted Average	100.00%	8.54%	6.24%	6.94%

8.4 SUMMARY

FEI's 2027 Forecast equity financing and ROE are based on the same percentages as approved by Order G-236-23. FEI's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates. The 2027 Forecast embedded rate on long-term debt is expected to increase slightly to 4.74 percent from the 2026 Approved rate of 4.73 percent. For the short-term interest rate, FEI is forecasting an interest rate of 3.72 percent in 2027.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FEI's forecasts of property taxes and income tax which have been completed on a basis consistent with prior years. For 2027, property taxes are forecast to increase by approximately 13.2 percent from 2026 Approved, while income tax is forecast to decrease by approximately 30.3 percent when compared to 2026 Approved.

9.2 PROPERTY TAXES

The property taxes are calculated by incorporating FEI's forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from gas consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

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

Line No.	Description	2026 Approved	2026 Projected	2027 Forecast
1	Distribution Assets	$ 33.291	$ 34.741	$ 37.857
2	Transmission Assets	23.485	28.255	29.172
3	Gas Storage Assets	8.393	8.526	8.899
4	Manufactured Gas Assets	0.072	0.055	0.054
5	General Assets	7.027	7.146	7.456
6	In-Lieu	16.203	16.081	16.749
7	BCER Fees	0.295	0.283	0.285
8	Total Property Taxes	88.766	95.087	100.471
9	Less: Property Tax Transferred to RNG	(0.190)	(0.061)	(0.082)
10	Net Property Tax	88.576	95.026	100.389
11				
12	2026 Projected and 2027 Forecast Compared to 2026 Approved		7.3%	13.2%
13	2027 Forecast Compared to 2026 Projected			5.7%

As shown in the above table, the 2026 property taxes are projected to increase by 7.3 percent from 2026 Approved. The 2026 Projected property taxes are estimated based on actual tax rates and assessed values for 2026. The majority of the increase from 2026 Approved to 2026 Projected is related to transmission assets as a result of higher assessed values and new transmission asset additions in 2026.

For 2027, FEI is forecasting an increase in property taxes of approximately 5.7 percent from the 2026 Projected level. The most significant drivers of the forecast changes from 2026 Projected to 2027 Forecast are as follows:

1. ***Changes in Tax Rates.*** Mill rates are expected to change for 2027 as follows:
   a) Municipal general mill rates are expected to increase on average by approximately 3.0 percent in 2027 across FEI's operating municipalities; however, since many municipalities are already at the legislated rate cap of $40 per $1,000 of assessment value on utility properties, the increases due to changes in tax rates are tempered;
   b) Rural general mill rates are expected to increase in 2027 by approximately 3.0 percent, from the 2026 rate of $3.47 to $3.57 per $1,000 of assessed value;
   c) School mill rates are expected to increase in 2027 by approximately 3.0 percent, from the 2026 rate of $12.06 to $12.42 per $1,000 of assessed value; and
   d) Other mill rates are expected to increase by approximately 1.5 percent in 2027, primarily from Regional Districts, Hospital Districts and Transit Authority taxes.
2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Grants in-lieu to municipalities are anticipated to increase by 4.2 percent compared to 2026 Projected. As in-lieu taxes are calculated as a fixed percentage of revenues, any fluctuations in overall revenues reported to municipalities will directly impact the amount of In-Lieu taxes owed.
3. ***Changes in Assessed Values.*** Forecast changes in the assessed values of FEI's property are based on expected inflationary changes to BC Assessment legislated improvement rates, pipeline additions and land values. BC Assessment uses a five-year rolling average to estimate inflation when setting rates. The forecast changes are as follows:
   a) 6.1 percent increase in assessed values of distribution lines and services plus additional new construction;
   b) 6.1 percent increase in assessed values of transmission lines;
   c) 2.5 percent increase in assessed values for LNG improvements;
   d) 2.0 percent decrease in office improvements; and
   e) Land values are expected to be flat except for the legislated Right-of-Way rate which is expected to increase by 3.0 percent.

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 recovered from customers in the following year.

9.3 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2027, which is unchanged from 2026. The corporate tax rates used in this Application are based on the *Canada*

Income Tax Act and the *BC Income Tax Act* enacted legislation and are updated each year as part of the annual rate-setting process.

For 2027, FEI is forecasting income taxes to be $78.624 million, which is approximately $34.104 million or 30.3 percent lower compared to 2026 Approved. The decrease in income tax expenses is primarily attributable to an increase in CCA deductions, partially offset by a higher rate base and higher depreciation of property, plant and equipment. The increase in CCA deductions is primarily due to higher UCC additions in 2027 when compared to 2026 Approved as well as the following new tax legislation:

- On April 16, 2024, the Federal government proposed an immediate expensing of new additions related to productivity-enhancing assets such as general electronic data-processing equipment, which enabled FEI to claim a 100 percent CCA deduction for property that was acquired after April 15, 2024 and before 2027; and
- On December 16, 2024, the Federal government proposed to reinstate and extend the Accelerated Investment Incentive rules, which enabled FEI to claim an additional CCA deduction for all qualifying expenditures made after January 1, 2025 and before 2034 (formally known as the Reaccelerated Investment Incentive rules or RII).

The above-described legislation received royal assent on March 26, 2026; as such, the benefit of the additional CCA deductions in income tax has been incorporated in the 2027 Forecast. FEI notes that the additional CCA deductible for 2025 and 2026 resulting from the enacted legislation is $36 million and $23 million, respectively. This is equivalent to approximately $15.9 million of income tax savings, which FEI has recorded in the Flow-through deferral account and which will be returned to customers through amortization. Please refer to Section 12.4.2.2.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 *SUMMARY*

FEI has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes in property tax rates and assessments.

10. EARNINGS SHARING AND RATE RIDERS

10.1 *INTRODUCTION AND OVERVIEW*

In this section, FEI discusses earnings sharing and the calculation of its delivery rate riders. FEI proposes to distribute a $0.710 million pre-tax credit ($0.518 million after-tax) earnings sharing amount to customers as part of the 2027 delivery rates. FEI has also set out the RSAM, Fort Nelson Residential Common Rate Phase-in, and Clean Growth Innovation Fund (CGIF) rate riders for 2027 and provides details on the CGIF, which is funded through the collection of the CGIF rate rider.

10.2 *EARNINGS SHARING*

In the RSF Decision (at page 18), the BCUC approved the continuation of the same earnings sharing mechanism utilized during the 2020-2024 MRP term, whereby 50 percent of the achieved ROE above or below the allowed ROE is shared with customers.

Since FEI is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FEI distributes earnings sharing amounts. This is consistent with the calculations of formula O&M and formula Growth capital, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2027 delivery rates, it is the 2025 formula O&M, 2025 Growth capital, and 2025 earnings sharing amounts that are calculated and impact rates in 2027.

For 2027, FEI proposes to distribute a $0.710 million pre-tax credit ($0.518 million after-tax) to customers, comprised of:

- The $0.333 million credit difference between the projected 2025 deferral account after-tax addition of zero embedded in 2026 delivery rates, and the actual 2025 deferral account after-tax credit addition of $0.333 million;
- The $0.141 million credit difference between the projected 2025 financing addition of $0.265 million credit[52] and the actual 2025 financing addition of $0.406 million credit;
- The $0.029 million credit difference between the forecast 2026 financing addition of zero[53] embedded in 2026 delivery rates, and the projected 2026 financing addition of $0.029 million credit embedded in this Application; and
- 2027 forecast financing of $0.015 million (credit).[54]

---

[52] Annual Review for 2025 and 2026 Delivery Rates, Section 10.2.
[53] Annual Review for 2025 and 2026 Delivery Rates, Compliance Filing dated December 9, 2025, Section 11 – 2026, Schedule 12, Line 25, Column 4.
[54] Section 11, Schedule 12, Line 26, Column 4.

FEI proposes to distribute $0.710 million to customers in 2027 as a reduction in 2027 revenue requirements through amortization of the projected 2027 opening after-tax balance as well as 2027 Projected financing of $0.518 million in the Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2026 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2026 ROE variance from approved.

10.3 *RATE RIDERS*

There are two delivery rate riders that are set through the Annual Review process. These are the RSAM Rate Rider and the Fort Nelson Residential Common Rate Phase-in Rate Rider. Additionally, pursuant to the RSF Decision, FEI was approved to collect a basic charge fixed rate rider of $0.40 per month from all non-bypass customers for the term of the RSF to support FEI's CGIF activities.

10.3.1 RSAM Rate Rider

The RSAM rate rider collects or refunds the previous year's projected RSAM balance from RS 1, 2, 3 and 23 customers over two years. The projected 2026 ending balance of the RSAM account, including interest, is a debit of $83.309 million. Based on the 2027 Forecast demand from RS 1, 2, 3, and 23 customers, the 2027 RSAM rider is $0.406 per GJ, as shown in Table 10-1.

Table 10-1: 2027 RSAM Rate Rider

2026 RSAM + Interest Closing Balance ($000)	83,309
Amortization Period (Years)	2
2027 Amortization Post-Tax ($000)	41,654
Tax Rate	27%
2027 Amortization Pre-Tax ($000)	57,061

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization (S000)	2027 Volume (TJ)	Rider ($/GJ)
Rate 1/1BU/1U/1X		80,002.4	0.406
Rate 2/2BU/2U/2X		29,561.5	0.406
Rate 3/3BU/3U/3X		28,488.7	0.406
Rate 23		2,439.4	0.406
	57,061	140,492.0	0.406

The differences that result from the actual 2026 ending RSAM balance varying from the projection, and the actual 2027 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2028 RSAM rate rider and, in this way, refunded to or collected from customers.

10.3.2 Fort Nelson Residential Customer Common Rate Phase-in Rate Rider

Pursuant to Order G-278-22, FEI is approved to phase-in the implementation of common rates to the Fort Nelson service area (FEFN) residential customers over a five-year period through the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider. The rider is to be calculated each year as part of FEI's Annual Review and is based on the updated forecast of FEFN's residential customer demand and the remaining balance of the deferral account each year over the five-year phase-in period. FEI notes that 2027 is the final year for the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider.

Table 10-2 below provides the calculation of the 2027 Fort Nelson Residential Customer Common Rate Phase-in Rate Rider, which is nil, reflecting the completion of the five-year common rate phase-in period in 2027.

Table 10-2: 2027 Fort Nelson Residential Customer Common Rate Phase-in Rider

Line	Particular	Reference	2027
1	FEFN (RS 1) Delivery Margin @ Existing Rate w/o Rider ($000s)		2,583.6
2	FEFN (RS 1) Delivery Margin (RS 1) @ Existing Rate w/ Rider ($000s)		2,524.9
3	Incremental Delivery Margin from FEFN RS 1 ($000s)	Line 1 - Line 2	58.7
4			
5	Effective Incremental Delivery Rate ($/GJ)	Line 3 / Line 12	0.254
6	Annual Incremental of Phase-In ($/GJ)	Line 5 / 1 Year (Remaining) for 2027	0.254
7			
8	**FEFN Residential Common Rate Phase-in ($/GJ)**	**-(Line 5 - Line 6)**	-
11			
12	2027 FEFN Residential Demand Forecast (TJ)		231.2

10.3.3 Clean Growth Innovation Fund (CGIF)

The CGIF is an important and effective mechanism that supports provincial decarbonization goals by advancing innovative technologies that help FEI and its customers lower GHG emissions while maintaining the use of the gas system. In addition, the CGIF provides FEI with direct exposure to the start-up companies and academic institutions researching and developing the technologies. This direct exposure facilitates the development of internal FEI knowledge through CGIF learnings and supports FEI's advancement of the energy transition in the interests of its customers.

The CGIF was established as part of the 2020-2024 MRP (2020 CGIF), with FEI collecting $0.40 per month per customer through the CGIF rider. In the RSF Decision, the BCUC approved the continuation of the CGIF for the term of the RSF (2025 CGIF), including the $0.40 per month per CGIF rate rider. FEI was directed to return the ending balance of the 2020 CGIF to customers through amortization of the balance over one year in 2025. FEI was further directed to return any residual balance in the 2025 CGIF to customers at the end of the RSF term.[55]

10.3.3.1 CGIF Forecast and Deferral Account Summary

FEI is forecasting to collect $5.345 million in 2027.

Table 10-3 below shows the amounts collected and the amounts expended for clean growth projects since 2025.

Table 10-3: Clean Growth Innovation Fund 2025-2027 Deferral Account Continuity ($ millions)

	Actual 2025	Actual Jan - Jun 2026	Projected Jul - Dec 2026	Forecast 2027	Total
Portfolio Approvals	$ 2.542	$ 4.067		$ -	**$ 6.609**
Forecast Approvals			$ 2.000	$ 7.000	**$ 9.000**
Net Approvals	**$ 2.542**	**$ 4.067**	**$ 2.000**	**$ 7.000**	**$ 15.609**
Opening Balance	**$ -**	**$ (2.034)**	**$ (4.051)**	**$ (2.022)**	**$ -**
Funding collected	(5.280)	(2.634)	(2.682)	(5.345)	(15.942)
Expenditures	2.661	-	5.500	7.500	15.661
Accrued committed	-	-	-	-	-
Tax	0.707	0.711	(0.761)	(0.582)	0.076
Financing	(0.122)	(0.094)	(0.028)	(0.077)	(0.321)
Closing Balance	**$ (2.034)**	**$ (4.051)**	**$ (2.022)**	**$ (0.526)**	**$ (0.526)**

To date, FEI has approved 16 projects totalling $6.609 million under the 2025 CGIF.

10.3.3.1.1 GOVERNANCE

FEI has continued to maintain the governance structure that was established under the 2020 CGIF.

CGIF portfolios are first reviewed by FEI subject matter experts. The recommendations of the Company's subject matter experts are reviewed by the CGIF Steering Team (CGIF-ST) and are either approved or rejected. Some proposals are approved by the CGIF-ST with conditions. The CGIF-ST is comprised of FEI senior managers that provide leadership to a variety of departments that are key to assessing the technical and business aspects of the portfolio proposals.

Proposals recommended by the Company's subject matter experts are presented to the External Advisory Council (EAC) for input and comment that will support final portfolio approvals. The input and comments from the EAC are considered throughout the decision process.

The CGIF Executive Steering Committee (ESC) is the final stage of portfolio review and is responsible for: (1) making a final decision regarding which projects, if any, within a given portfolio

[55] RSF Decision and Order G-69-25, pp. 82-83.

are approved; and (2) providing overall strategic direction over CGIF expenditures. The ESC reviews each portfolio with the benefit of recommendations and summaries of the commentary received from FEI subject matter experts, the CGIF-ST and the EAC to determine whether a project should be approved.

10.3.3.1.2 INVESTMENT PROFILE

Grants from the 2025 CGIF are focused on several application areas critical for decarbonizing FEI's gas system: production; distribution; end-use; carbon capture, utilization and storage (CCUS); and generalized low-carbon initiatives.

Production applications are related to creating renewable, low-carbon hydrogen, RNG and syngas for distribution through the gas network or direct end-use near the production facility. Distribution applications focus on accommodating renewable hydrogen in the existing gas system. End-use applications focus on more effective uses of energy sources and the ability to use renewable fuels in end-use applications, creating hybrid energy systems that efficiently use both gaseous fuels and electricity. Overlaying these three application areas are generalized low-carbon investments and CCUS.

The total approved investment in these application categories, and subcategories, is shown in Table 10-4.

Table 10-4: 2025 CGIF Approved Investment by Application ($ millions)

Application	Sub-Application	Approved Grant
Production	Renewable Hydrogen	1.000
	Renewable Natural Gas	0.722
	Renewable Syngas	0.680
	Subtotal	**2.402**
Distribution	Renewable Hydrogen	0.000
	Subtotal	**0.000**
End-Use	Energy Efficiency	0.147
	Hybrid Systems	0.000
	Renewable Hydrogen	0.000
	Demand Response	0.124
	Transporation	0.060
	Subtotal	**0.331**
Carbon Capture	Carbon capture	0.141
	Utilization	2.284
	Storage	0.000
	Subtotal	**2.426**
General Low-Carbon	General Initiatives	1.450
	Subtotal	**1.450**
Total		**6.609**

The approved grant commitments to date are diversified across renewable hydrogen, renewable natural gas, energy efficiency, transportation, CCUS, and general low-carbon initiatives. FEI provides further details as follows:

- $2.402 million for lower-carbon fuels production, which includes $1.0 million for a hydrogen pyrolysis pilot project, two projects that are testing technologies at existing RNG facilities in BC to improve methane production, and a project to advance preliminary development of a syngas demonstration project in conjunction with a pulp mill located in BC;
- $2.284 million for four projects that will research and demonstrate the utilization of solid carbon created from methane pyrolysis to produce low-cost hydrogen; and
- $1.450 million in general low-carbon initiatives, which include FEI's continued participation in the Natural Gas Innovation Fund, as well as FEI's participation in the Emerging Fuels and Technologies Program.

10.4 *SUMMARY*

As discussed in Section 10.2 above, FEI proposes to distribute a $0.710 million pre-tax credit ($0.518 million after-tax) earnings sharing amount to customers as part of 2027 delivery rates.

In Section 10.3, FEI provides information on its 2027 delivery rate riders. For the RSAM rate rider, FEI is proposing to set the 2027 rider at $0.406 per GJ. For the Fort Nelson Residential Common Rate Phase-in Rate Rider, the rate is nil, reflecting the completion of the five-year common rate phase-in period in 2027. FEI has also provided details on the CGIF in Section 10.3.3, which is funded through the collection of the basic charge CGIF rider.

11. FINANCIAL SCHEDULES

11.1 *2027 FINANCIAL SCHEDULES*

Description	**Schedule Reference**
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Non-Reg Plant Continuity Schedule	8
Contributions In Aid Of Construction Continuity Schedule	9
Net Salvage Continuity Schedule	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Deferred Income Tax Liability / Asset	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Cost Of Energy	18
Margin And Revenue At Existing And Revised Rates	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2027
($millions)

Schedule 1

Line No.	Particulars	2027 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ 6.406		
3	Change in Other Revenue	0.292	6.698	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	6.940		
7	Capitalized Overhead Change	(1.156)	5.784	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions	15.586	15.586	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.175)		
14	Deferrals	(9.008)	(9.183)	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	0.769		
18	Financing Ratio Changes	0.019		
19	Rate Base Growth	48.538	49.326	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	11.813		
23	Other Income Taxes Changes	(34.104)	(22.291)	
24				
25	**REVENUE DEFICIENCY (SURPLUS)**		**$ 45.920**	Schedule 16, Line 11, Column 4
26				
27	Non-Bypass Margin at 2026 Approved Rates		1,338.460	Schedule 19, Line 17, Column 3
28	Rate Change		3.43%	

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 9,617,728	$ 9,973,356	$ 355,628	Schedule 6.2, Line 34, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 34, Column 4
3	Net Additions	294,631	3,287,730	2,993,099	Schedule 6.2, Line 34, Columns 5+6+7
4	Plant in Service, Ending	9,912,359	13,261,086	3,348,727	
5					
6	Accumulated Depreciation Beginning	$ (2,998,344)	$ (3,095,194)	$ (96,850)	Schedule 7.2, Line 34, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 34, Column 6
8	Net Additions	(47,072)	(50,848)	(3,776)	Schedule 7.2, Line 34, Columns 7+8
9	Accumulated Depreciation Ending	(3,045,416)	(3,146,042)	(100,626)	
10					
11	CIAC, Beginning	$ (480,816)	$ (492,144)	$ (11,328)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(11,328)	(2,163,082)	(2,151,754)	Schedule 9, Line 6, Columns 5+6
14	CIAC, Ending	(492,144)	(2,655,226)	(2,163,082)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 217,479	$ 225,507	$ 8,028	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,026	8,201	175	Schedule 9, Line 13, Columns 5+6
19	Accumulated Amortization Ending - CIAC	225,505	233,708	8,203	
20					
21	Net Plant in Service, Mid-Year	$ 6,478,176	$ 7,152,526	$ 674,350	
22					
23	Adjustment for timing of Capital additions	$ 108,607	$ (45,504)	$ (154,111)	
24	Capital Work in Progress, No AFUDC	42,350	89,506	47,156	
25	Unamortized Deferred Charges	145,715	294,969	149,254	Schedule 11.1, Line 26, Column 10
26	Working Capital	63,302	47,580	(15,722)	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	990,672	1,109,867	119,195	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(990,672)	(1,109,867)	(119,195)	Schedule 15, Line 6, Column 3
29					
30	Mid-Year Utility Rate Base	$ 6,838,150	$ 7,539,077	$ 700,927	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	Reference	2025	2026	2027	Total for 2027 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Formula Cost Drivers**						
2	CPI		3.012%	2.397%	2.134%		
3	AWE		5.384%	3.982%	2.767%		
4	Labour Split						
5	Non Labour		50.000%	50.000%	50.000%		
6	Labour		50.000%	50.000%	50.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	4.198%	3.190%	2.451%		
8	Productivity Factor		-0.550%	-0.550%	-0.550%		
9	Net Inflation Factor	Line 7 + Line 8	3.648%	2.640%	1.901%		
10							
11							
12	**Growth in Average Customer Calculation**						
13	Actual/Projected Prior Year Average Customers		1,093,663	1,101,521	1,107,581		
14	Average Customers for the Year	Schedule 19, Line 29, Column 9	1,101,521	1,107,581	1,113,599		
15	Change in Average Customers	Line 14 - Line 13	7,858	6,060	6,018	19,936	
16	Customer Growth Factor Multiplier					100%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16				19,936	
18							
19							
20	**Average Customer Forecast - Rate Setting Purposes**	Line 14				1,113,599	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Schedule 4

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Inflation Indexed Capital Growth**					
2	2026 Unit Cost Growth Capital	$ 9,893				
3	2027 Net Inflation Factor	1.901%				Schedule 3, Line 9, Column 5
4	2027 Unit Cost Growth Capital	$ 10,081				
5	2027 Gross Customer Additions	8,800				
6	2027 Inflation Indexed Growth Capital	$ 88,713			$ 88,713	
7	2025 Growth Capital Customer True-Up				13,148	
8	2027 System Extension Fund				1,000	
9	2027 Growth CIAC				1,520	
10	2027 Inflation Indexed Gross Growth Capital				$ 104,381	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 1,012		
14	RNG Assets			16,029		
15	NGT Assets			-		
16	Sustainment Capital			125,484		
17	Other Capital			61,213		
18	Sub-total			$ 203,738	203,738	
19						
20	**Total Capital Expenditures Before CIAC**				$ 308,119	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Schedule 5

Line No.	Particulars		2027 Forecast	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	104,381	Schedule 4, Line 10, Column 5
3	Forecast Capital Expenditures		203,738	Schedule 4, Line 18, Column 5
4	Total Capital Expenditures	$	308,119	
5				
6	**Special Projects and CPCN's**			
7	ITS TIMC CPCN Project	$	555	
8	AMI CPCN Project		207,829	
9	OCMP CPCN Project		5,523	
10	Tilbury Expansion Project		138,738	
11	CTS Expansion Project		20,000	
12	Tilbury LNG Storage Expansion (TLSE) CPCN Project		28,200	
13	Enterprise Resource Planning (ERP) Modernization Project		48,842	
14	EGP Project		2,420,492	
15	Total Capital Expenditures	$	2,870,179	
16				
17	**Total Capital Expenditures**	$	3,178,298	
18				
19				
20	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
21				
22	Regular Capital Expenditures	$	308,119	Line 4
23	Add - Capitalized Overheads		61,393	Schedule 20, Line 28, Column 4
24	Add - AFUDC		4,300	
25	Gross Capital Expenditures		373,812	
26	Change in Work in Progress		(11,099)	
27	**Total Regular Additions to Plant**	$	362,713	
28				
29	Special Projects and CPCN's Capital Expenditures	$	2,870,179	Line 15
30	Add - AFUDC		38,989	
31	Gross Capital Expenditures		2,909,168	
32	Change in Work in Progress		280,319	
33	**Total Special Projects and CPCN Additions to Plant**	$	3,189,487	
34				
35	**Grand Total Additions to Plant**	$	3,552,200	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/2026	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	178-00	Organization Expense	728	-	-	-	-	728	
4	401-01	Franchise and Consents	197	-	-	-	-	197	
5	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
6	440-02	Water/Land Rights Tilbury	4,299	-	-	-	-	4,299	
7	461-01	Transmission Land Rights	54,379	-	-	-	-	54,379	
8	461-02	Transmission Land Rights - Mt. Hayes	643	-	-	-	-	643	
9	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
10	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
11	471-01	Distribution Land Rights	7,180	-	-	-	-	7,180	
12	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
13	402-06	AMI Software	10,346	-	2,988	-	-	13,334	
14	402-01	Application Software - 12.5%	88,077	-	-	11,415	(7,060)	92,432	
15	402-02	Application Software - 20%	42,613	-	-	11,232	(6,250)	47,595	
16			$ 210,519	$ -	$ 2,988	$ 22,647	$ (13,310)	$ 222,844	
17									
18		**MANUFACTURED GAS / LOCAL STORAGE**							
19	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
20	432-00	Manufact'd Gas - Struct. & Improvements	1,312	-	-	-	-	1,312	
21	433-00	Manufact'd Gas - Equipment	2,122	-	-	-	-	2,122	
22	434-00	Manufact'd Gas - Gas Holders	2,948	-	-	-	-	2,948	
23	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
24	437-00	Manufact'd Gas - Measuring & Regulating Equipment	2,518	-	-	-	-	2,518	
25	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
26	442-00	Structures & Improvements (Tilbury)	101,354	-	-	-	-	101,354	
27	443-00	Gas Holders - Storage (Tilbury)	184,971	-	-	-	-	184,971	
28	448-11	Piping (Tilbury)	53,015	-	-	-	-	53,015	
29	448-21	Pre-treatment (Tilbury)	34,307	-	-	-	-	34,307	
30	448-31	Liquefaction Equipment (Tilbury)	90,421	-	-	-	-	90,421	
31	449-00	Local Storage Equipment (Tilbury)	23,905	-	-	-	-	23,905	
32	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
33	442-01	Structures & Improvements (Mount Hayes)	19,355	-	-	-	-	19,355	
34	443-05	Gas Holders - Storage (Mount Hayes)	61,907	-	-	-	-	61,907	
35	448-41	Send out Equipment(Tilbury)	30,919	-	200	-	-	31,119	
36	448-51	Sub-station and Electric (Tilbury)	39,805	-	2,738	-	-	42,543	
37	448-61	Control Room (Tilbury)	5,034	-	-	-	-	5,034	
38	448-10	Piping (Mount Hayes)	12,714	-	-	-	-	12,714	
39	448-20	Pre-treatment (Mount Hayes)	29,462	-	-	-	-	29,462	
40	448-30	Liquefaction Equipment (Mount Hayes)	28,940	-	-	-	-	28,940	
41	448-40	Send out Equipment (Mount Hayes)	23,743	-	-	-	-	23,743	
42	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
43	448-60	Control Room (Mount Hayes)	6,674	-	-	-	-	6,674	
44	448-65	MH Inspection (Mount Hayes)	-	-	-	-	-	-	
45	448-66	Tilbury LNG - Inspection	5,476	-	-	-	-	5,476	
46	449-01	Local Storage Equipment (Mount Hayes)	6,133	-	-	-	-	6,133	
47			$ 805,468	$ -	$ 2,938	$ -	$ -	$ 808,406	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	12/31/2026	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 11,086	$ -	$ 58,110	$ -	$ -	$ 69,196	
3	462-00	Compressor Structures	53,904	-	203,385	2,677	(418)	259,548	
4	463-00	Measuring Structures	29,234	-	58,110	-	(244)	87,100	
5	464-00	Other Structures & Improvements	17,522	-	-	2,212	(3)	19,731	
6	465-00	Mains	1,988,938	-	2,384,095	38,167	(3,521)	4,407,679	
7	465-20	Mains - INSPECTION	72,042	-	-	17,939	(3,611)	86,370	
8	465-11	IP Transmission Pipeline - Whistler	60,674	-	-	-	-	60,674	
9	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
10	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
11	466-00	Compressor Equipment	214,976	-	261,495	4,152	(1,076)	479,547	
12	466-10	Compressor Equipment - OVERHAUL	1,191	-	-	5	(127)	1,069	
13	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,746	-	-	1,143	-	9,889	
14	467-10	Measuring & Regulating Equipment	190,937	-	-	9,509	(1,127)	199,319	
15	467-20	Telemetering	35,000	-	-	-	(57)	34,943	
16	467-31	IP Intermediate Pressure Whistler	400	-	-	35	-	435	
17	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
18	468-00	Communication Structures & Equipment	10,352	-	-	3,657	-	14,009	
19			$ 2,702,971	$ -	$ 2,965,195	$ 79,496	$ (10,184)	$ 5,737,478	
20									
21		**DISTRIBUTION PLANT**							
22	470-00	Land in Fee Simple	$ 6,349	$ -	$ -	$ -	$ -	$ 6,349	
23	472-00	Structures & Improvements	71,842	-	-	2,094	(153)	73,783	
24	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
25	473-00	Services	1,853,013	-	-	84,446	(3,656)	1,933,803	
26	474-00	House Regulators & Meter Installations	75,118	-	-	-	(48,165)	26,953	
27	474-03	AMI Meter Installation	97,978	-	104,113	-	-	202,091	
28	474-02	Meters/Regulators Installations	242,442	-	-	25,123	(94,550)	173,015	
29	475-00	Mains	2,592,449	-	-	69,128	(4,138)	2,657,439	
30	476-00	Compressor Equipment	614	-	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	285,420	-	-	15,856	(2,778)	298,498	
32	477-20	Telemetering	37,820	-	-	890	(133)	38,577	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
34	478-10	Meters	290,574	-	-	20,485	(73,758)	237,301	
35	478-12	AMI Meters	37,695	-	100,849	-	-	138,544	
36	478-20	Instruments	19,548	-	-	844	-	20,392	
37			$ 5,611,139	$ -	$ 204,962	$ 218,866	$ (227,331)	$ 5,807,636	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 10,658	$ -	$ -	$ 234	$ -	$ 10,892	
41	475-10	Bio Gas Mains – Municipal Land	11,159	-	-	3,468	-	14,627	
42	475-20	Bio Gas Mains – Private Land	1,175	-	-	-	-	1,175	
43	418-10	Bio Gas Purification Overhaul	21	-	-	1	-	22	
44	418-20	Bio Gas Purification Upgrader	62,371	-	-	456	-	62,827	
45	477-40	Bio Gas Reg & Meter Equipment	8,099	-	-	759	-	8,858	
46	478-30	Bio Gas Meters	431	-	-	18	-	449	
47	474-10	Bio Gas Reg & Meter Installations	4,144	-	-	115	-	4,259	
48	483-25	RNG Comp S/W	-	-	-	-	-	-	
49	465-40	Bio Gas Transmission Pipe	4,694	-	-	-	-	4,694	
50	466-40	Bio Gas Compressor Equipment	3,438	-	-	-	-	3,438	
51			$ 106,190	$ -	$ -	$ 5,051	$ -	$ 111,241	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.2
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	12/31/2026	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,864	$ -	$ -	$ -	$ -	$ 17,864	
3	476-20	NG Transportation LNG Dispensing Equipment	13,526	-	-	-	-	13,526	
4	476-30	NG Transportation CNG Foundations	3,163	-	-	-	-	3,163	
5	476-40	NG Transportation LNG Foundations	1,049	-	-	-	-	1,049	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	-	-	-	-	77	
7	476-60	NG Transportation CNG Dehydrator	805	-	-	-	-	805	
8			$ 36,484	$ -	$ -	$ -	$ -	$ 36,484	
9									
10		**GENERAL PLANT & EQUIPMENT**							
11	480-00	Land in Fee Simple	$ 31,944	$ -	$ -	$ -	$ -	$ 31,944	
12	482-10	Frame Buildings	28,430	-	-	-	(406)	28,024	
13	482-20	Masonry Buildings	154,785	-	-	3,812	(96)	158,501	
14	482-30	Leasehold Improvement	4,512	-	-	-	(3)	4,509	
15	483-30	GP Office Equipment	3,056	-	-	491	(451)	3,096	
16	483-40	GP Furniture	28,064	-	-	3,752	(3)	31,813	
17	483-10	GP Computer Hardware	41,311	-	-	11,208	(8,004)	44,515	
18	483-20	GP Computer Software	8,594	-	-	-	(1,047)	7,547	
19	484-00	Vehicles	85,720	-	-	9,634	-	95,354	
20	484-10	Vehicles - Leased	847	-	-	-	(1,482)	(635)	
21	485-10	Heavy Work Equipment	735	-	-	-	-	735	
22	485-20	Heavy Mobile Equipment	15,124	-	-	-	-	15,124	
23	486-00	Small Tools & Equipment	67,392	-	-	5,848	(2,009)	71,231	
24	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
25	488-30	AMI Communication and Equipment	9,238	-	13,404	-	-	22,642	
26	488-10	Telephone	93	-	-	-	(26)	67	
27	488-20	Radio	20,740	-	-	1,908	(118)	22,530	
28			$ 500,585	$ -	$ 13,404	$ 36,653	$ (13,645)	$ 536,997	
29									
30		**UNCLASSIFIED PLANT**							
31	499-00	Plant Suspense	-	-	-	-	-	-	
32			$ -	$ -	$ -	$ -	$ -	$ -	
33									
34		**Total Plant in Service**	$ 9,973,356	$ -	$ 3,189,487	$ 362,713	$ (264,470)	$ 13,261,086	
35									
36		Cross Reference			Schedule 5, Line 33, Column 2	Schedule 5, Line 27, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2026	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2027	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 70	$ -	$ 1	$ -	$ -	$ -	$ 71	
3	178-00	Organization Expense	728	1.00%	493	-	7	-	-	-	500	
4	401-01	Franchise and Consents	197	2.50%	154	-	5	-	-	-	159	
5	402-03	Other Intangible Plant	1,907	2.50%	1,485	-	48	-	-	-	1,533	
6	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
7	461-01	Transmission Land Rights	54,379	0.00%	1,766	-	-	-	-	-	1,766	
8	461-02	Transmission Land Rights - Mt. Hayes	643	0.00%	-	-	-	-	-	-	-	
9	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
10	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
11	471-01	Distribution Land Rights	7,180	0.00%	248	-	-	-	-	-	248	
12	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
13	402-06	AMI Software	13,334	10.00%	-	-	1,333	-	-	-	1,333	
14	402-01	Application Software - 12.5%	88,077	12.50%	38,095	-	11,010	(7,060)	-	-	42,045	
15	402-02	Application Software - 20%	42,613	20.00%	14,718	-	8,523	(6,250)	-	-	16,991	
16			$ 213,507		$ 57,049	$ -	$ 20,927	$ (13,310)	$ -	$ -	$ 64,666	
17												
18		**MANUFACTURED GAS / LOCAL STORAGE**										
19	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	432-00	Manufact'd Gas - Struct. & Improvements	1,312	2.50%	590	-	33	-	-	-	623	
21	433-00	Manufact'd Gas - Equipment	2,122	5.00%	690	-	106	-	-	-	796	
22	434-00	Manufact'd Gas - Gas Holders	2,948	2.50%	1,239	-	74	-	-	-	1,313	
23	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	257	-	15	-	-	-	272	
24	437-00	Manufact'd Gas - Measuring & Regulating Equipment	2,518	5.00%	1,706	-	126	-	-	-	1,832	
25	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
26	442-00	Structures & Improvements (Tilbury)	101,354	3.70%	24,482	-	3,750	-	-	-	28,232	
27	443-00	Gas Holders - Storage (Tilbury)	184,971	1.71%	33,489	-	3,163	-	-	-	36,652	
28	448-11	Piping (Tilbury)	53,015	2.50%	9,731	-	1,325	-	-	-	11,056	
29	448-21	Pre-treatment (Tilbury)	34,307	4.01%	10,403	-	1,376	-	-	-	11,779	
30	448-31	Liquefaction Equipment (Tilbury)	90,421	2.50%	17,414	-	2,261	-	-	-	19,675	
31	449-00	Local Storage Equipment (Tilbury)	23,905	2.10%	15,027	-	502	-	-	-	15,529	
32	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
33	442-01	Structures & Improvements (Mount Hayes)	19,355	3.06%	10,959	-	592	-	-	-	11,551	
34	443-05	Gas Holders - Storage (Mount Hayes)	61,907	1.65%	15,741	-	1,021	-	-	-	16,762	
35	448-41	Send out Equipment(Tilbury)	31,119	2.50%	1,760	-	778	-	-	-	2,538	
36	448-51	Sub-station and Electric (Tilbury)	42,543	2.50%	7,311	-	1,064	-	-	-	8,375	
37	448-61	Control Room (Tilbury)	5,034	6.75%	2,192	-	340	-	-	-	2,532	
38	448-10	Piping (Mount Hayes)	12,714	2.43%	4,665	-	309	-	-	-	4,974	
39	448-20	Pre-treatment (Mount Hayes)	29,462	3.71%	17,637	-	1,093	-	-	-	18,730	
40	448-30	Liquefaction Equipment (Mount Hayes)	28,940	2.42%	11,081	-	700	-	-	-	11,781	
41	448-40	Send out Equipment (Mount Hayes)	23,743	2.43%	8,936	-	577	-	-	-	9,513	
42	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.43%	8,300	-	529	-	-	-	8,829	
43	448-60	Control Room (Mount Hayes)	6,674	5.01%	6,089	-	334	-	-	-	6,423	
44	448-65	MH Inspection (Mount Hayes)	-	20.00%	-	-	-	-	-	-	-	
45	448-66	Tilbury LNG - Inspection	5,476	20.00%	3,286	-	1,095	-	-	-	4,381	
46	449-01	Local Storage Equipment (Mount Hayes)	6,133	3.47%	1,989	-	213	-	-	-	2,202	
47			$ 808,406		$ 214,975	$ -	$ 21,376	$ -	$ -	$ -	$ 236,351	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2026	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2027	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 69,196	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	462-00	Compressor Structures	257,289	2.97%	27,515	-	1,601	(418)	-	-	28,698	
4	463-00	Measuring Structures	87,344	2.19%	11,015	-	640	(244)	-	-	11,411	
5	464-00	Other Structures & Improvements	17,522	3.31%	5,579	-	580	(3)	-	-	6,156	
6	465-00	Mains	4,373,033	2.96%	594,328	-	30,320	(3,521)	-	-	621,127	
7	465-20	Mains - INSPECTION	72,042	15.20%	22,327	-	10,950	(3,611)	-	-	29,666	
8	465-11	IP Transmission Pipeline - Whistler	60,674	1.53%	12,836	-	928	-	-	-	13,764	
9	465-30	Mt Hayes - Mains	6,307	1.54%	1,564	-	97	-	-	-	1,661	
10	465-10	Mains - Byron Creek	1,371	5.03%	1,911	-	69	-	-	-	1,980	
11	466-00	Compressor Equipment	476,471	2.31%	127,108	-	4,966	(1,076)	-	-	130,998	
12	466-10	Compressor Equipment - OVERHAUL	1,191	10.19%	1,043	-	121	(127)	-	-	1,037	
13	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,746	2.28%	2,558	-	199	-	-	-	2,757	
14	467-10	Measuring & Regulating Equipment	190,937	2.27%	43,156	-	4,334	(1,127)	-	-	46,363	
15	467-20	Telemetering	35,000	6.01%	19,430	-	2,104	(57)	-	-	21,477	
16	467-31	IP Intermediate Pressure Whistler	400	2.14%	163	-	9	-	-	-	172	
17	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	80	-	7	-	-	-	87	
18	468-00	Communication Structures & Equipment	10,352	0.00%	3,691	-	-	-	-	-	3,691	
19			$ 5,668,166		$ 874,807	$ -	$ 56,925	$ (10,184)	$ -	$ -	$ 921,548	
20												
21		**DISTRIBUTION PLANT**										
22	470-00	Land in Fee Simple	$ 6,349	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
23	472-00	Structures & Improvements	71,842	2.01%	18,174	-	1,444	(153)	-	-	19,465	
24	472-10	Structures & Improvements - Byron Creek	124	4.67%	112	-	6	-	-	-	118	
25	473-00	Services	1,853,013	2.11%	547,744	-	39,099	(3,656)	-	-	583,187	
26	474-00	House Regulators & Meter Installations	75,118	4.35%	78,724	-	3,268	(49,617)	-	-	32,375	
27	474-03	AMI Meter Installation	202,091	5.00%	4,899	-	10,105	-	-	-	15,004	
28	474-02	Meters/Regulators Installations	242,442	4.55%	73,498	-	11,031	(41,425)	-	-	43,104	
29	475-00	Mains	2,592,449	1.42%	713,087	-	36,813	(4,138)	-	-	745,762	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	285,420	2.66%	90,559	-	7,592	(2,778)	-	-	95,373	
32	477-20	Telemetering	37,820	4.97%	13,689	-	1,880	(133)	-	-	15,436	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	290,574	3.38%	179,418	-	9,821	(73,980)	-	-	115,259	
35	478-12	AMI Meters	138,544	5.00%	1,885	-	6,927	-	-	-	8,812	
36	478-20	Instruments	19,548	2.86%	10,093	-	559	-	-	-	10,652	
37			$ 5,816,101		$ 1,733,523	$ -	$ 128,545	$ (175,880)	$ -	$ -	$ 1,686,188	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 10,658	2.69%	$ 591	$ -	$ 287	$ -	$ -	$ -	$ 878	
41	475-10	Bio Gas Mains – Municipal Land	11,159	1.54%	723	-	172	-	-	-	895	
42	475-20	Bio Gas Mains – Private Land	1,175	1.53%	79	-	18	-	-	-	97	
43	418-10	Bio Gas Purification Overhaul	21	5.00%	13	-	1	-	-	-	14	
44	418-20	Bio Gas Purification Upgrader	62,371	5.00%	8,491	-	3,119	-	-	-	11,610	
45	477-40	Bio Gas Reg & Meter Equipment	8,099	3.24%	1,469	-	262	-	-	-	1,731	
46	478-30	Bio Gas Meters	431	5.19%	67	-	22	-	-	-	89	
47	474-10	Bio Gas Reg & Meter Installations	4,144	5.08%	494	-	211	-	-	-	705	
48	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
49	465-40	Bio Gas Transmission Pipe	4,694	1.53%	72	-	72	-	-	-	144	
50	466-40	Bio Gas Compressor Equipment	3,438	2.42%	83	-	83	-	-	-	166	
51			$ 106,190		$ 12,082	$ -	$ 4,247	$ -	$ -	$ -	$ 16,329	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2026	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2027	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Natural Gas for Transportation**										
2	476-10	NG Transportation CNG Dispensing Equipment	17,864	5.00%	$ 7,668	-	893	-	-	-	$ 8,561	
3	476-20	NG Transportation LNG Dispensing Equipment	13,526	5.00%	7,666	-	676	-	-	-	8,342	
4	476-30	NG Transportation CNG Foundations	3,163	5.00%	1,486	-	158	-	-	-	1,644	
5	476-40	NG Transportation LNG Foundations	1,049	5.00%	655	-	52	-	-	-	707	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	10.00%	78	-	1	-	-	-	79	
7	476-60	NG Transportation CNG Dehydrator	805	5.00%	346	-	40	-	-	-	386	
8			$ 36,484		$ 17,899	$ -	$ 1,820	$ -	$ -	$ -	$ 19,719	
9												
10		**GENERAL PLANT & EQUIPMENT**										
11	480-00	Land in Fee Simple	$ 31,944	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
12	482-10	Frame Buildings	28,430	2.75%	17,286	-	782	(406)	-	-	17,662	
13	482-20	Masonry Buildings	154,785	1.36%	44,692	-	2,105	(96)	-	-	46,701	
14	482-30	Leasehold Improvement	4,512	9.49%	345	-	428	(3)	-	-	770	
15	483-30	GP Office Equipment	3,056	6.67%	1,394	-	204	(451)	-	-	1,147	
16	483-40	GP Furniture	28,064	5.00%	9,207	-	1,403	(3)	-	-	10,607	
17	483-10	GP Computer Hardware	41,311	25.00%	14,748	-	10,328	(8,004)	-	-	17,072	
18	483-20	GP Computer Software	8,594	12.50%	4,411	-	1,074	(1,047)	-	-	4,438	
19	484-00	Vehicles	85,720	7.15%	44,481	-	6,129	-	-	-	50,610	
20	484-10	Vehicles - Leased	847	9.44%	847	-	-	(1,482)	-	-	(635)	
21	485-10	Heavy Work Equipment	735	4.04%	567	-	30	-	-	-	597	
22	485-20	Heavy Mobile Equipment	15,124	8.51%	8,680	-	1,287	-	-	-	9,967	
23	486-00	Small Tools & Equipment	67,392	5.00%	27,862	-	3,370	(2,009)	-	-	29,223	
24	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
25	488-30	AMI Communication and Equipment	22,642	6.67%	-	-	1,510	-	-	-	1,510	
26	488-10	Telephone	93	6.67%	78	-	(6)	(26)	-	-	46	
27	488-20	Radio	20,740	6.67%	10,244	-	1,383	(118)	-	-	11,509	
28			$ 513,989		$ 184,859	$ -	$ 30,027	$ (13,645)	$ -	$ -	$ 201,241	
29												
30		**UNCLASSIFIED PLANT**										
31	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
32			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
33												
34		**Total**	$ 13,162,843		$ 3,095,194	$ -	$ 263,867	$ (213,019)	$ -	$ -	$ 3,146,042	
35		Less: Depreciation & Amortization Transferred to RNG Account					(4,247)					
36		Less: Vehicle Depreciation Allocated To Capital Projects					(2,268)					
37		**Net Depreciation Expense**					$ 257,352					
38												
39		Cross Reference	Schedule 6.2, Line 34, Columns 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars			12/31/2026	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Non-Regulated Plant**									
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	-	176,594	
4									-	
5	**Total**			$ 177,648	$ -	$ -	$ -	$ -	$ 177,648	
6										
7										
8										

9 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
10 **FOR THE YEAR ENDING DECEMBER 31, 2027**
11 **($000s)**
12
13

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2026	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2027	Cross Reference
16	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
17										
18	**Non-Regulated Plant Depreciation**									
19	NRB Depreciation @ 0%	$ 1,054	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	NRB Depreciation @ 2.4%	176,594	2.40%	159,605	-	4,238	-	-	163,843	
21									-	
22	**Total**	$ 177,648		$ 159,605	$ -	$ 4,238	$ -	$ -	$ 163,843	

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	12/31/2026	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 322,181	$ -	$ -	$ 1,520	$ -	$ 323,701	
3	Transmission Contributions	165,876	2,155,495	-	6,067	-	2,327,438	
4	Others	3,521	-	-	-	-	3,521	
5	RNG	566	-	-	-	-	566	
6	**Total**	$ 492,144	$ 2,155,495	$ -	$ 7,587	$ -	$ 2,655,226	
7								
8	**Amortization**							
9	Distribution Contributions	$ (153,563)	$ -	$ -	$ (5,542)	$ -	$ (159,105)	
10	Transmission Contributions	(69,982)	-	-	(2,455)	-	(72,437)	
11	Others	(1,548)	-	-	(176)	-	(1,724)	
12	RNG	(414)	-	-	(28)	-	(442)	
13	**Total**	$ (225,507)	$ -	$ -	$ (8,201)	$ -	$ (233,708)	
14								
15	**Net CIAC**	$ 266,637	$ 2,155,495	$ -	$ (614)	$ -	$ 2,421,518	
16								
17								
18	Total CIAC Amortization Expense per Line 13, Column 5				$ (8,201)			
19	Less: CIAC Amortization Transferred to RNG Account				28			
20	**Net CIAC Amortization Expense**				$ (8,173)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2026	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	461-01	Transmission Land Rights	$ 54,379	0.00%	$ 146	$ -	$ -	$ 146	
3	471-01	Distribution Land Rights	7,180	0.00%	5	-	-	5	
4			$ 61,559		$ 151	$ -	$ -	$ 151	
5									
6		**MANUFACTURED GAS / LOCAL STORAGE**							
7	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 2,518	0.00%	$ (22)	$ -	$ -	$ (22)	
8	442-00	Structures & Improvements (Tilbury)	101,354	0.30%	4,849	304	-	5,153	
9	443-00	Gas Holders - Storage (Tilbury)	184,971	0.30%	12,763	555	-	13,318	
10	448-11	Piping (Tilbury)	53,015	0.24%	1,233	127	-	1,360	
11	448-21	Pre-treatment (Tilbury)	34,307	0.34%	1,317	117	-	1,434	
12	448-31	Liquefaction Equipment (Tilbury)	90,421	0.46%	4,329	416	-	4,745	
13	449-00	Local Storage Equipment (Tilbury)	23,905	-0.17%	1,953	(41)	-	1,912	
14	442-01	Structures & Improvements (Mount Hayes)	19,355	0.40%	854	77	-	931	
15	443-05	Gas Holders - Storage (Mount Hayes)	61,907	0.36%	2,188	223	-	2,411	
16	448-41	Send out Equipment(Tilbury)	31,119	0.25%	183	78	-	261	
17	448-51	Sub-station and Electric (Tilbury)	42,543	0.48%	1,605	204	-	1,809	
18	448-10	Piping (Mount Hayes)	12,714	0.28%	339	36	-	375	
19	448-20	Pre-treatment (Mount Hayes)	29,462	0.48%	1,409	141	-	1,550	
20	448-30	Liquefaction Equipment (Mount Hayes)	28,940	0.57%	1,618	165	-	1,783	
21	448-40	Send out Equipment (Mount Hayes)	23,743	0.28%	648	66	-	714	
22	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.57%	1,209	124	-	1,333	
23	449-01	Local Storage Equipment (Mount Hayes)	6,133	0.14%	162	9	-	171	
24			$ 768,195		$ 36,637	$ 2,601	$ -	$ 39,238	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2026	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 257,289	0.12%	$ 771	$ 65	$ -	$ 836	
3	463-00	Measuring Structures	87,344	0.46%	1,276	134	-	1,410	
4	464-00	Other Structures & Improvements	17,522	0.25%	300	44	-	344	
5	465-00	Mains	4,373,033	0.47%	70,263	9,629	-	79,892	
6	465-11	IP Transmission Pipeline - Whistler	60,674	0.33%	1,829	200	-	2,029	
7	465-30	Mt Hayes - Mains	6,307	0.31%	195	20	-	215	
8	466-00	Compressor Equipment	476,471	0.10%	3,284	215	-	3,499	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,746	0.13%	128	11	-	139	
10	467-10	Measuring & Regulating Equipment	190,937	0.14%	2,020	267	-	2,287	
11	467-20	Telemetering	35,000	0.02%	(14)	7	-	(7)	
12	467-31	IP Intermediate Pressure Whistler	400	0.19%	11	1	-	12	
13	468-00	Communication Structures & Equipment	10,352	0.00%	401	-	-	401	
14			$ 5,524,075		$ 80,464	$ 10,593	$ -	$ 91,057	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 6,349	0.00%	$ (2,099)	$ -	$ -	$ (2,099)	
18	472-00	Structures & Improvements	71,842	0.53%	2,229	381	-	2,610	
19	473-00	Services	1,853,013	2.47%	164,948	45,769	(23,776)	186,941	
20	474-00	House Regulators & Meter Installations	75,118	0.87%	8,343	654	-	8,997	
21	474-03	AMI Meter Installation	202,091	1.58%	-	3,193	-	3,193	
22	474-02	Meters/Regulators Installations	242,442	0.00%	749	-	-	749	
23	475-00	Mains	2,592,449	0.56%	103,935	14,518	-	118,453	
24	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
25	477-10	Measuring & Regulating Equipment	285,420	0.40%	8,900	1,142	-	10,042	
26	477-20	Telemetering	37,820	0.31%	769	117	-	886	
27	478-10	Meters	290,574	-0.17%	1,544	(494)	-	1,050	
28	478-12	AMI Meters	-	0.00%	-	-	-	-	
29			$ 5,657,732		$ 290,024	$ 65,280	$ (23,776)	$ 331,528	
30									
31		**BIO GAS**							
32	472-20	Bio Gas Struct. & Improvements	$ 10,658	0.28%	$ 49	$ 30	$ -	$ 79	
33	475-10	Bio Gas Mains – Municipal Land	11,159	0.38%	196	42	-	238	
34	475-20	Bio Gas Mains – Private Land	1,175	0.39%	17	5	-	22	
35	418-20	Bio Gas Purification Upgrader	62,371	0.25%	388	156	-	544	
36	477-40	Bio Gas Reg & Meter Equipment	8,099	0.01%	(24)	1	-	(23)	
37	474-10	Bio Gas Reg & Meter Installations	4,144	1.29%	126	53	-	179	
38	465-40	Bio Gas Transmission Pipe	4,694	0.33%	5	15	-	20	
39	466-40	Bio Gas Compressor Equipment	3,438	0.07%	2	2	-	4	
40			$ 105,738		$ 759	$ 304	$ -	$ 1,063	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Schedule 10.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2026	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2027	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,864	0.00%	$ (1)	$ -	$ -	$ (1)	
3	476-20	NG Transportation LNG Dispensing Equipment	13,526	0.00%	10	-	-	10	
4	476-40	NG Transportation LNG Foundations	1,049	0.00%	9	-	-	9	
5	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	0.00%	16	-	-	16	
6			$ 32,516		$ 34	$ -	$ -	$ 34	
7									
8		**GENERAL PLANT & EQUIPMENT**							
9	482-10	Frame Buildings	$ 28,430	0.38%	$ 227	$ 108	$ -	$ 335	
10	482-20	Masonry Buildings	154,785	0.18%	1,321	279	-	1,600	
11	482-30	Leasehold Improvement	4,512	0.00%	(116)	-	-	(116)	
12	483-30	GP Office Equipment	3,056	0.00%	1	-	-	1	
13	483-40	GP Furniture	28,064	0.00%	(94)	-	-	(94)	
14	484-00	Vehicles	85,720	-1.55%	(7,810)	(1,329)	-	(9,139)	
15	485-10	Heavy Work Equipment	735	-0.18%	(38)	(1)	-	(39)	
16	485-20	Heavy Mobile Equipment	15,124	1.72%	(816)	260	-	(556)	
17	486-00	Small Tools & Equipment	67,392	0.00%	70	-	-	70	
18	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
19	488-20	Radio	20,740	0.00%	(7)	-	-	(7)	
20			$ 408,558		$ (7,264)	$ (683)	$ -	$ (7,947)	
21									
22		**Total**	$ 12,558,373		$ 400,805	$ 78,095	$ (23,776)	$ 455,124	
23		Less: Depreciation & Amortization Transferred to RNG Account				(304)			
24		**Net Salvage Depreciation Expense**				$ 77,791			
25		Cross Reference	Schedule 6.2, Columns 3+4+5				Schedule 11.1, Line 3, Column 4		

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	12/31/2026	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2027	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ 99,364	$ -	$ -	$ -	$ -	$ (68,057)	$ 18,375	$ 49,682	$ 74,523	
3	Commodity Cost Reconciliation Account (CCRA)	(24,510)	-	33,575	(9,065)	-	-	-	-	(12,255)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	81,580	-	-	-	-	(55,877)	15,087	40,790	61,185	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	4,147	-	(1,509)	407	324	(2,553)	690	1,506	2,827	
6	SCP Net Mitigation Revenues Variance Account	-	-	-	-	-	-	-	-	-	
7	Pension & OPEB Variance	(610)	-	-	-	(335)	-	-	(945)	(778)	
8	BCUC Levies Variance	(413)	-	-	-	413	-	-	-	(207)	
9		$ 159,558	$ -	$ 32,066	$ (8,658)	$ 402	$ (126,487)	$ 34,152	$ 91,033	$ 125,296	
10											
11	**2. Rate Smoothing Accounts**										
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM)	$ 459,443	$ 116,878	$ 60,000	$ (16,200)	$ (83,352)	$ -	$ -	$ 536,769	$ 556,545	
15	NGV Conversion Grants	13	-	51	(14)	(3)	-	-	47	30	
16	Emissions Regulations	(19,185)	-	200	(54)	19,185	-	-	146	(9,520)	
17	Greenhouse Gas Reduction Regulation Incentives	27,039	-	-	-	(5,308)	-	-	21,731	24,385	
18	CNG and LNG Recoveries	(819)	-	(1,556)	420	819	-	-	(1,136)	(978)	
19	2025-2027 RSF Application	270	-	-	-	(232)	-	-	38	154	
20	BCUC Initiated Inquiry Costs	(16)	-	-	-	16	-	-	-	(8)	
21	2028 Rate Framework Application	15	-	540	(146)	-	-	-	409	212	
22	2021 Generic Cost of Capital Proceeding	527	-	-	-	(176)	-	-	351	439	
23	2024-2027 DSM Expenditures Schedule Application	42	-	-	-	(42)	-	-	-	21	
24	2023 Cost of Service Allocation Study	(23)	-	-	-	23	-	-	-	(12)	
25	OCMP Application and Preliminary Stage Development Costs	11,614	-	-	-	(5,811)	-	-	5,803	8,709	
26		$ 478,920	$ 116,878	$ 59,235	$ (15,994)	$ (74,881)	$ -	$ -	$ 564,158	$ 579,978	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	12/31/2026	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2027	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 2,026	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 1,289	$ 1,658	
3	Net Salvage Provision/Cost	(405,213)	-	23,776	-	(78,095)	-	-	(459,532)	(432,373)	
4	PCEC Start Up Costs	392	-	-	-	(44)	-	-	348	370	
5	2022 Long Term Gas Resource Plan Application	569	-	-	-	(569)	-	-	-	285	
6	2026 Long-term Gas Resource Plan Application	2,093	-	-	-	(698)	-	-	1,395	1,744	
7	2021 Renewable Gas Program Comprehensive Review	658	-	-	-	(658)	-	-	-	329	
8	Transmission Integrity Management Capabilities	1,991	-	-	-	(1,991)	-	-	-	996	
9	Annual Review Proceeding Costs	102	-	150	(41)	(102)	-	-	109	106	
10	2026 MX Policies Review	243	-	-	-	(243)	-	-	-	122	
11	Regional Gas Supply Diversity Project Development Costs	2,518	-	-	-	(1,259)	-	-	1,259	1,889	
12	TLSE Application and Preliminary Stage Development Costs	2,107	-	-	-	(1,044)	-	-	1,063	1,585	
13	ERP Application and Preliminary Stage Development	-	2,263	-	-	(566)	-	-	1,697	1,980	
14		$ (392,514)	$ 2,263	$ 23,926	$ (41)	$ (86,006)	$ -	$ -	$ (452,372)	$ (421,312)	
15											
16	**4. Retroactive Expense Accounts**										
17											
18	**5. Other Accounts**										
19	Pension & OPEB Funding	$ (77,021)	$ -	$ 10,970	$ -	$ -	$ -	$ -	$ (66,051)	$ (71,536)	
20	US GAAP Pension & OPEB Funded Status	(13,192)	-	-	-	-	-	-	(13,192)	(13,192)	
21	Existing Meter Cost Recovery	37,093	-	26,648	-	(8,342)	-	-	55,399	46,246	
22	Previously Retired Meter Cost Recovery	41,692	-	24,803	-	(8,910)	-	-	57,585	49,639	
23	Residual Delivery Rate Riders	(299)	-	-	-	299	-	-	-	(150)	
24		$ (11,727)	$ -	$ 62,421	$ -	$ (16,953)	$ -	$ -	$ 33,741	$ 11,007	
25											
26	**Total**	$ 234,237	$ 119,141	$ 177,648	$ (24,693)	$ (177,438)	$ (126,487)	$ 34,152	$ 236,560	$ 294,969	
27	Less: Net Salvage Amortization Transferred to RNG Account					304					
28	**Net Rate Base Deferred Amortization Expense**					$ (177,134)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	12/31/2026	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2027	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	RNG Account	$ 28,896	$ (12,382)	$ 184,708	$ (48,543)	$ -	$ (164,654)	$ 44,457	$ 32,482	$ 24,498	
3	Flowthrough	(26,138)	-	(791)	-	26,929	-	-	-	(13,069)	
4	RNG Mitigation Revenue	(2,487)	12,382	(13,540)	3,645	-	-	-	-	4,948	
5	Marketer Cost Variance	32	-	(44)	12	-	-	-	-	16	
6		$ 303	$ -	$ 170,333	$ (44,886)	$ 26,929	$ (164,654)	$ 44,457	$ 32,482	$ 16,393	
7											
8	**2. Rate Smoothing Accounts**										
9	City of Vancouver Biomethane Purchase Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	64	-	2	-	(66)	-	-	-	32	
11	2023-2025 Revenue Deficiency	83,815	-	4,707	-	(16,763)	-	-	71,759	77,787	
12		$ 83,879	$ -	$ 4,709	$ -	$ (16,829)	$ -	$ -	$ 71,759	$ 77,819	
13											
14	**3. Benefits Matching Accounts**										
15	Demand-Side Management (DSM) - Non Rate Base	$ 116,878	$ (116,878)	$ 97,784	$ (25,814)	$ -	$ -	$ -	$ 71,970	$ 35,985	
16	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
17	Clean Growth Innovation Fund 2025-2027	(2,022)	-	7,423	(2,025)	-	(5,345)	1,443	(526)	(1,274)	
18	ERP Project Implementation O&M	191	-	1,595	(418)	-	-	-	1,368	780	
19	ERP Application and Preliminary Stage Development	2,263	(2,263)	-	-	-	-	-	-	-	
20		$ 114,912	$ (119,141)	$ 106,802	$ (28,257)	$ -	$ (5,345)	$ 1,443	$ 70,414	$ 33,093	
21											
22	**4. Retroactive Expense Accounts**										
23											
24	**5. Other Accounts**										
25	Mark to Market - Hedging Transactions	$ 57,048	$ -	$ -	$ -	$ -	$ -	$ -	$ 57,048	$ 57,048	
26	Earnings Sharing Account	(503)	-	(15)	-	518	-	-	-	(252)	
27	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
28	FEFN - Right-Of-Way Agreement	209	-	13	-	-	-	-	222	216	
29	Flotation Costs	17,948	-	985	-	(4,332)	-	-	14,601	16,275	
30	AMI Foreign Exchange (FX) Mark to Market Valuation	-	-	-	-	-	-	-	-	-	
31	TLSE Foreign Exchange (FX) Mark to Market Valuation	-	-	-	-	-	-	-	-	-	
32		$ 74,702	$ -	$ 983	$ -	$ (3,814)	$ -	$ -	$ 71,871	$ 73,287	
33											
34	**Total Non Rate Base Deferral Accounts**	$ 273,796	$ (119,141)	$ 282,827	$ (73,143)	$ 6,286	$ (169,999)	$ 45,900	$ 246,526	$ 200,591	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 13,881	$ 13,572	$ (309)	Schedule 14, Line 29, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,753	1,845	92	
6	Employee Withholdings	(7,755)	(8,389)	(634)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	1,796	1,518	(278)	
10	Gas In Storage	50,377	34,813	(15,564)	
11	Inventories - Materials and Supplies	3,286	4,239	953	
12	Refundable Contributions	(36)	(18)	18	
13					
14	Total	$ 63,302	$ 47,580	$ (15,722)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2027 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 1,074,646	38.5	$ 41,373,871		
4	Commercial Tariff Revenue	568,804	37.6	21,387,031		
5	Industrial Tariff Revenue	206,648	45.3	9,361,154		
6	Bypass and Special Rates	57,006	40.0	2,280,240		
7						
8	**Other Revenue**					
9	Late Payment Charges	3,474	52.9	183,775		
10	Application Charges	1,480	38.1	56,388		
11	Other Utility Income	42,767	38.1	1,629,423		
12						
13	Total	$ 1,954,825		$ 76,271,882	39.0	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 479,871	(40.1)	$ (19,242,827)		
17	Operating and Maintenance	353,027	(29.9)	(10,555,507)		
18	Property Taxes	100,389	(0.6)	(60,233)		
19	Operating Fees	12,100	(343.9)	(4,161,054)		
20	GST	53,489	(33.3)	(1,781,190)		
21	PST	48,362	(40.9)	(1,978,013)		
22	Income Tax	78,624	(15.2)	(1,195,085)		
23						
24	Total	$ 1,125,862		$ (38,973,909)	(34.6)	
25						
26	Net Lag (Lead) Days				4.4	
27	Total Expenses				$ 1,125,862	
28						
29	Cash Working Capital				$ 13,572	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Schedule 15

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (743,781)	$ (846,023)	$ (102,242)	
2	Tax Gross Up	(275,097)	(312,913)	(37,816)	
3	DIT Liability/Asset - End of Year	$ (1,018,878)	$ (1,158,936)	$ (140,058)	
4	DIT Liability/Asset - Opening Balance	(962,466)	(1,060,797)	(98,331)	
5					
6	DIT Liability/Asset - Mid Year	$ (990,672)	$ (1,109,867)	$ (119,195)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast at Existing Rates	2027 Forecast Revised Revenue	2027 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	170,371	170,420		170,420	49	
3	Transportation Volume (TJ)	51,829	47,801		47,801	(4,028)	
4		222,200	218,221	-	218,221	(3,979)	Schedule 17, Line 23, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,874,089	$ 1,785,549	$ -	$ 1,785,549	$ (88,540)	
8	Deficiency (Surplus)	-	-	43,575	43,575	43,575	
9	Transportation	77,889	75,635	-	75,635	(2,254)	
10	Deficiency (Surplus)	-		2,345	2,345	2,345	
11	Total	1,951,978	1,861,184	45,920	1,907,104	(44,874)	Schedule 19, Line 29, Column 8
12				-			
13	**COST OF ENERGY**	564,259	479,871	-	479,871	(84,388)	Schedule 18, Line 23, Column 3
14							
15	**MARGIN**	1,387,719	1,381,313	45,920	1,427,233	39,514	
16							
17	**EXPENSES**						
18	O&M Expense (net)	347,243	353,027	-	353,027	5,784	Schedule 20, Line 29, Column 4
19	Depreciation & Amortization	413,624	420,027	-	420,027	6,403	Schedule 21, Line 15, Column 3
20	Property Taxes	88,576	100,389	-	100,389	11,813	Schedule 22, Line 8, Column 3
21	Other Revenue	(48,013)	(47,721)	-	(47,721)	292	Schedule 23, Line 12, Column 3
22	Utility Income Before Income Taxes	586,289	555,591	45,920	601,511	15,222	
23							
24	Income Taxes	112,728	66,228	12,396	78,624	(34,104)	Schedule 24, Line 13, Column 3
25							
26	**EARNED RETURN**	$ 473,561	$ 489,363	$ 33,524	$ 522,887	$ 49,326	Schedule 26, Line 5, Column 7
27							
28	**UTILITY RATE BASE**	$ 6,838,150	$ 7,538,619		$ 7,539,077	$ 700,927	Schedule 2, Line 30, Column 3
29	**RATE OF RETURN ON UTILITY RATE BASE**	6.93%	6.49%		6.94%	0.01%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Schedule 17

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	81,390.1	80,002.4	(1,387.7)	
4	Commercial				
5	Rate Schedule 2	29,419.1	29,561.5	142.4	
6	Rate Schedule 3	30,668.2	28,488.7	(2,179.5)	
7	Rate Schedule 23	2,498.9	2,439.4	(59.5)	
8	Industrial				
9	Rate Schedule 4	175.1	188.1	13.0	
10	Rate Schedule 5	16,034.9	16,694.1	659.2	
11	Rate Schedule 6	19.9	19.2	(0.7)	
12	Rate Schedule 7	9,204.4	9,603.1	398.7	
13	Rate Schedule 22 - Firm Service	14,183.6	14,165.9	(17.7)	
14	Rate Schedule 22 - Interruptible Service	9,938.8	8,013.9	(1,924.9)	
15	Rate Schedule 25	6,232.4	5,416.2	(816.2)	
16	Rate Schedule 27	2,819.4	3,368.1	548.7	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	10,641.2	8,920.6	(1,720.6)	
19	Rate Schedule 25	758.2	722.9	(35.3)	
20	Rate Schedule 46	3,459.2	5,863.2	2,404.0	
21	Byron Creek	11.4	8.9	(2.5)	
22	VIGJV	4,745.0	4,745.0	-	
23	Total	222,199.8	218,221.2	(3,978.6)	
24					
25	**REVENUE AT EXISTING RATES**				
26	Residential				
27	Rate Schedule 1	$ 1,101,141	$ 1,046,814	$ (54,327)	
28	Commercial				
29	Rate Schedule 2	316,155	303,662	(12,493)	
30	Rate Schedule 3	271,922	238,424	(33,498)	
31	Rate Schedule 23	13,703	13,373	(330)	
32	Industrial				
33	Rate Schedule 4	1,049	994	(55)	
34	Rate Schedule 5	105,179	100,517	(4,662)	
35	Rate Schedule 6	144	130	(14)	
36	Rate Schedule 7	47,554	44,684	(2,870)	
37	Rate Schedule 22 - Firm Service	17,178	17,915	737	
38	Rate Schedule 22 - Interruptible Service	12,266	9,855	(2,411)	
39	Rate Schedule 25	21,347	19,874	(1,473)	
40	Rate Schedule 27	6,738	7,936	1,198	
41	Bypass and Special Rates				
42	Rate Schedule 22 - Firm Service	865	827	(38)	
43	Rate Schedule 25	425	425	-	
44	Rate Schedule 46	30,945	50,324	19,379	
45	Byron Creek	136	137	1	
46	VIGJV	5,231	5,293	62	
47	Total	$ 1,951,978	$ 1,861,184	$ (90,794)	

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 278,334	$ 235,623	$ (42,711)	
4	Commercial				
5	Rate Schedule 2	101,356	87,500	(13,856)	
6	Rate Schedule 3	99,963	78,927	(21,036)	
7	Rate Schedule 23	57	42	(15)	
8	Industrial				
9	Rate Schedule 4	507	449	(58)	
10	Rate Schedule 5	46,296	39,701	(6,595)	
11	Rate Schedule 6	44	32	(12)	
12	Rate Schedule 7	26,657	22,912	(3,745)	
13	Rate Schedule 22 - Firm Service	327	244	(83)	
14	Rate Schedule 22 - Interruptible Service	229	137	(92)	
15	Rate Schedule 25	143	93	(50)	
16	Rate Schedule 27	65	58	(7)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	245	153	(92)	
19	Rate Schedule 25	17	12	(5)	
20	Rate Schedule 46	10,019	13,988	3,969	
21	Byron Creek	-	-	-	
22	VIGJV	-	-	-	
23	Total	$ 564,259	$ 479,871	$ (84,388)	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved Margin	2027 Forecast Margin at Existing Rates	2027 Forecast Effective Increase	2027 Forecast Margin at Revised Rates	2027 Forecast Revenue at Existing Rates	2027 Forecast Effective Increase	2027 Forecast Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 822,807	$ 811,191	$ 27,832	$ 839,023	$ 1,046,814	$ 27,832	$ 1,074,646	1,010,125	80,002.4	
4	Commercial										
5	Rate Schedule 2	214,799	216,162	7,416	223,578	303,662	7,416	311,078	94,099	29,561.5	
6	Rate Schedule 3	171,959	159,497	5,472	164,969	238,424	5,472	243,896	7,802	28,488.7	
7	Rate Schedule 23	13,646	13,331	457	13,788	13,373	457	13,830	377	2,439.4	
8	Industrial										
9	Rate Schedule 4	542	545	19	564	994	19	1,013	22	188.1	
10	Rate Schedule 5	58,883	60,816	2,086	62,902	100,517	2,086	102,603	801	16,694.1	
11	Rate Schedule 6	100	98	3	101	130	3	133	21	19.2	
12	Rate Schedule 7	20,897	21,772	747	22,519	44,684	747	45,431	62	9,603.1	
13	Rate Schedule 22 - Firm Service	16,851	17,671	606	18,277	17,915	606	18,521	24	14,165.9	
14	Rate Schedule 22 - Interruptible Service	12,037	9,718	333	10,051	9,855	333	10,188	5	8,013.9	
15	Rate Schedule 25	21,204	19,781	679	20,460	19,874	679	20,553	185	5,416.2	
16	Rate Schedule 27	6,673	7,878	270	8,148	7,936	270	8,206	48	3,368.1	
17	Total Non-Bypass	$ 1,360,398	$ 1,338,460	$ 45,920	$ 1,384,380	$ 1,804,178	$ 45,920	$ 1,850,098	1,113,571	197,960.6	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 620	$ 674		$ 674	$ 827		$ 827	6	8,920.6	
22	Rate Schedule 25	408	413		413	425		425	3	722.9	
23	Rate Schedule 46	20,926	36,336		36,336	50,324		50,324	17	5,863.2	
24	Byron Creek	136	137		137	137		137	1	8.9	
25	VIGJV	5,231	5,293		5,293	5,293		5,293	1	4,745.0	
26	Total Bypass & Special	$ 27,321	$ 42,853	$ -	$ 42,853	$ 57,006	$ -	$ 57,006	28	20,260.6	
27											
28											
29	Total	$ 1,387,719	$ 1,381,313	$ 45,920	$ 1,427,233	$ 1,861,184	$ 45,920	$ 1,907,104	1,113,599	218,221.2	
30											
31	**Effective Increase**			3.43%			2.55%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2026 Base Unit Cost O&M	$ 290			
3	2027 Net Inflation Factor	1.901%			Schedule 3, Line 9, Column 5
4	2027 Base Unit Cost O&M	$ 296			Line 2 x (1 + Line 3)
5					
6	2027 Average Customer Forecast - Rate Setting Purpose	1,113,599			Schedule 3, Line 20, Column 6
7					
8	2027 Inflation Indexed O&M before prior year True-up	$ 329,625			Line 4 x Line 6 / 1000
9					
10	2025 Average Customer True-up	(407)			
11					
12	2027 Inflation Indexed O&M	$ 329,218		$ 329,218	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 6,598		
16	Insurance		11,665		
17	Integrity O&M		15,400		
18	AMI Flowthrough O&M		21,386		
19	BCUC fees		7,453		
20	RNG O&M		8,978		
21	Renewable Gas Development		5,510		
22	NGT O&M		3,221		
23	Variable LNG Production		13,969		
24	Sub-total		$ 94,180	94,180	Sum of Lines 15 through 23
25					
26	**Total Gross O&M**			$ 423,398	Line 12 + Line 24
27	O&M Transferred to RNG Account			(8,978)	
28	Capitalized Overhead			(61,393)	-14.5 % x Line 26
29	**Net O&M Expense**			$ 353,027	Sum of Lines 26 through 28

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 247,972	$ 263,867	$ 15,895	Schedule 7.2, Line 34, Column 7
3	Depreciation & Amortization Transferred to RNG Account	(4,171)	(4,247)	(76)	Schedule 7.2, Line 35, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(2,035)	(2,268)	(233)	Schedule 7.2, Line 36, Column 7
5		241,766	257,352	15,586	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 176,345	$ 177,438	$ 1,093	Schedule 11.1, Line 26, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to RNG Account	(305)	(304)	1	Schedule 11.1, Line 27, Column 6
10	Non-Rate Base Deferrals	3,816	(6,286)	(10,102)	Schedule 12, Line 34, Column 6
11	CIAC	(8,026)	(8,201)	(175)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to RNG Account	28	28	-	Schedule 9, Line 19, Column 5
13		171,858	162,675	(9,183)	
14					
15	Total	$ 413,624	$ 420,027	$ 6,403	

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 72,563	$ 83,722	$ 11,159	
2	1% In-Lieu of Municipal Taxes	16,203	16,749	546	
3					
4	Total	$ 88,766	$ 100,471	$ 11,705	
5					
6	Total Property Tax Expense per Line 4	$ 88,766	$ 100,471	$ 11,705	
7	Less: Property Tax Transferred to RNG Account	(190)	(82)	108	
8	**Net Property Tax Expense**	$ 88,576	$ 100,389	$ 11,813	

Schedule 23

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 3,511	$ 3,474	$ (37)	
2	Application Charge	1,533	1,480	(53)	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	300	12	
5	SCP Third Party Revenue	13,284	13,284	-	
6	NGT Tanker Rental Revenue	1,067	1,089	22	
7	NGT Overhead and Marketing Recovery	228	203	(25)	
8	RNG Other Revenue	7,592	7,687	95	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,443	2,137	(306)	
11					
12	Total	$ 48,013	$ 47,721	$ (292)	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved	2027 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 473,561	$ 522,887	$ 49,326	Schedule 16, Line 26, Column 5
2	Deduct: Interest on Debt	(176,614)	(195,503)	(18,889)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	7,837	(114,808)	(122,645)	Line 35
4	Accounting Income After Tax	$ 304,784	$ 212,576	$ (92,208)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 417,512	$ 291,200	$ (126,312)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 112,728	$ 78,624	$ (34,104)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 112,728	$ 78,624	$ (34,104)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	241,766	257,352	15,586	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	179,856	170,848	(9,008)	Schedule 21, Lines 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,602	1,369	(233)	
22	Vehicles: Interest & Capitalized Depreciation	2,035	2,268	233	
23	Pension Expense	8,798	8,957	159	
24	OPEB Expense	2,903	3,166	263	
25					
26	Deductions:				
27	Capital Cost Allowance	(332,531)	(449,828)	(117,297)	Schedule 25, Line 24, Column 6
28	CIAC Amortization	(7,998)	(8,173)	(175)	Schedule 21, Lines 11+12, Column 3
29	Debt Issue Costs	(1,690)	(1,378)	312	
30	Pension Contributions	(18,317)	(19,109)	(792)	
31	OPEB Contributions	(3,750)	(3,984)	(234)	
32	Overheads Capitalized Expensed for Tax Purposes	(39,466)	(40,223)	(757)	
33	Removal Costs	(22,644)	(23,776)	(1,132)	Schedule 11.1, Line 3, Column 4
34	Major Inspection Costs	(3,927)	(13,497)	(9,570)	
35	Total	$ 7,837	$ (114,808)	$ (122,645)	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Class	CCA Rate	12/31/2026 UCC Balance	2027 Additions	Adjustments	2027 CCA	Forecast 12/31/2027 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 780,190	$ -	$ -	$ (31,208)	$ 748,982
2	1(b)	6%	150,980	10,209	5,104	(9,978)	151,211
3	2	6%	60,045	-	-	(3,603)	56,442
4	3	5%	1,248	-	-	(62)	1,186
5	6	10%	141	-	-	(14)	127
6	7	15%	23,774	3,427	1,714	(4,337)	22,864
7	8	20%	34,790	11,953	5,977	(10,544)	36,199
8	10	30%	15,874	9,634	4,817	(9,098)	16,410
9	10.1	30%	205	-	-	(62)	143
10	12	100%	-	22,282	-	(22,282)	-
11	13	manual	3,290	-	-	(662)	2,628
12	14.1 (pre 2017)	5%	10,622	-	-	(531)	10,091
13	14.1 (post 2016)	5%	11,669	-	-	(583)	11,086
14	17	8%	634	-	-	(51)	583
15	38	30%	1,597	-	-	(479)	1,118
16	43.1 (post 2024)	30%	8,132	501	1,169	(2,941)	5,692
17	43.2	50%	26	-	-	(13)	13
18	47	8%	102,693	-	-	(8,215)	94,478
19	47 (LNG Plant - post Feb 2015)	8%	143,307	750,000	175,000	(85,465)	807,842
20	49	8%	687,380	98,803	41,766	(66,236)	719,947
21	50	55%	4,082	11,141	5,570	(11,436)	3,787
22	51	6%	2,286,332	498,327	249,163	(182,028)	2,602,631
23							
24	Total		$ 4,327,011	$ 1,416,277	$ 490,280	$ (449,828)	$ 5,293,460

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	2026 Approved Earned Return	2027 Amount	2027 Ratio	2027 Average Embedded Cost	2027 Cost Component	2027 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 172,987	$ 4,039,203	53.58%	4.74%	2.54%	$ 191,512	$ 18,525	Schedule 27, Lines 26&28, Columns 5&6&7
2	Short Term Debt	3,627	107,289	1.42%	3.72%	0.05%	3,991	364	
3	Common Equity	296,947	3,392,585	45.00%	9.65%	4.34%	327,384	30,437	
4									
5	Total	$ 473,561	$ 7,539,077	100.00%		6.94%	$ 522,887	$ 49,326	
6									
7	Cross Reference		Schedule 2, Line 30, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2027
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	$ 147,710	$ 150,000	7.073%	$ 10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	138,709	-	2.644%	-	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,865	150,000	3.822%	5,733	
13	2017 Medium Term Debt Issue - Series 30	October 30, 2017	October 30, 2047	173,584	175,000	3.735%	6,536	
14	2018 Medium Term Debt Issue - Series 31	December 7, 2018	December 7, 2048	198,351	200,000	3.897%	7,794	
15	2019 Medium Term Debt Issue - Series 32	August 9, 2019	August 9, 2049	198,500	200,000	2.857%	5,714	
16	2020 Medium Term Debt Issue - Series 33	July 13, 2020	July 13, 2050	198,392	200,000	2.579%	5,158	
17	2021 Medium Term Debt Issue - Series 34	April 14, 2021	July 18, 2031	148,984	150,000	2.495%	3,743	
18	2022 Medium Term Debt Issue - Series 35	November 28, 2022	November 28, 2052	148,697	150,000	4.724%	7,086	
19	2025 Medium Term Debt Issue - Series 36	October 16, 2025	October 16, 2030	198,771	200,000	3.515%	7,030	
20	2026 Medium Term Debt Issue (Series B Renewal)	September 1, 2026	September 1, 2056	387,820	391,737	4.964%	19,448	
21	2027 Medium Term Debt Issue	July 1, 2027	July 1, 2057	594,000	302,466	4.964%	15,014	
22								
23	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
24	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
25								
26	Total				$ 4,039,203		$ 191,512	
27								
28	Average Embedded Cost					4.74%		
29								
30	* Interest Rate is Effective Interest Rate as it includes amortization of debt issue costs							

12. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

12.1 INTRODUCTION AND OVERVIEW

In this section, FEI discusses “Exogenous Factors” under the RSF, emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI seeks approval to record the 2026 actual flotation costs in the Flotation Costs deferral account, and provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FEI is permitted to adjust the cost of service for “Exogenous Factors” under the RSF. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FEI has been established at $0.500 million, as approved in the RSF Decision.

For 2027, FEI has not identified any items that merit exogenous factor treatment.

12.3 ACCOUNTING MATTERS

In the following section, FEI provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the 2014-2019 PBR Plan Decision and Order G-138-14, the BCUC directed FEI to “communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period.” Although this directive was not included as part of the 2020-2024 MRP Decision, FEI continued to provide accounting policy changes and updates as part of the Annual Reviews during the MRP term.

Consistent with the Annual Reviews during the PBR Plan and MRP terms, FEI will continue to provide accounting policy changes and updates as part of the Annual Reviews during the RSF term.

There are no new accounting policy changes that FEI is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2027.

12.4 *NON-RATE BASE DEFERRAL ACCOUNTS*

FEI maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and, subject to BCUC approval, attract a weighted average cost of capital (WACC) return (which is equal to a rate base return).

12.4.1 New Deferral Accounts

FEI is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the sub-sections below, FEI seeks approval to add the 2026 actual flotation costs to the previously approved Flotation Costs deferral account, and provides updated information on the Flow-through deferral account.

12.4.2.1 Flotation Costs Deferral Account

On June 9, 2025, the BCUC issued Order G-138-25 granting approval to FEI to establish a new non-rate base deferral account, titled the Flotation Costs deferral account, attracting interest at FEI's WACC, to record its actual flotation costs attributable to the equity injections by its parent company, Fortis Inc.

In accordance with Order G-138-25, FEI provides the necessary supporting information to record and recover the actual incurred flotation costs attributable to the equity injections received thus far in 2026 from Fortis Inc.

In the first quarter of 2026, FEI issued common equity shares in the amount of $100 million, as approved by Order G-29-26. Similar to the equity injections completed in 2023, 2024 and 2025, Fortis Inc. relied on its Dividend Reinvestment Plan (DRIP) program to fund FEI's equity injection in March 2026. Therefore, consistent with FEI's 2023, 2024 and 2025 flotation costs approved for recovery by the BCUC, FEI has computed its 2026 flotation costs based on Fortis Inc.'s DRIP discount of 2 percent after-tax (2.74 percent before-tax). Using the 2.74 percent DRIP discount, FEI calculates the actual 2026 flotation costs to be $2.740 million, as shown in the following table.

Table 12-1: 2026 Actual Equity Injection and Flotation Costs Calculation

FortisBC Energy Inc.	2026
Equity Injection	$ 100,000,000
Benchmark Flotation Cost Requested (before-tax)	2.74%
Total Amount for Recovery in Customer Rates (before-tax)	**$ 2,740,000**

FEI accordingly requests approval to record $2.740 million of actual flotations costs incurred for the 2026 equity issuance in the Flotation Costs deferral account. The after-tax costs will be captured in the Flotation Costs deferral account and will be amortized into rates over five years[56].

12.4.2.2 Flow-Through Deferral Account

As approved by the RSF Decision, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-7 of the RSF Application, reproduced below.

[56] The five-year amortization period was approved as part of the FEI Annual Review for 2025 and 2026 Delivery Rates Decision and Order G-287-25 (Directive 5.g).

Table 12-2: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Depreciation on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues:		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Revenues from CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate/timing variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Interest on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax variances due to changes in tax rates/laws	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Income tax on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, renewable and low carbon gas initiatives (biomethane service and renewable gas development), variable LNG production, integrity digs, AMI project, EV charging stations, MRS triennial audits, and MRS assessment reports.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, Methane Emission Mitigation, and EV DCFC stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA.

In accordance with the method set out in the table above, the calculation of the 2026 Projected Flow-through amount (credit of $20.492 million) is shown in Table 12-3 below. To calculate the overall combined amount to be distributed to customers (credit of $26.929 million), FEI has also included the following adjustments:

- The $4.715 million credit difference between the projected ending 2025 deferral account balance of zero[57] embedded in 2026 delivery rates, and the actual ending 2025 deferral account credit balance of $4.715 million. A more detailed breakdown of the 2025 variance is provided in Table 12-4 below;
- The $0.931 million credit difference between the forecast 2026 financing addition of zero[58] embedded in 2026 delivery rates, and the projected 2026 financing addition of $0.931 million credit embedded in this Application; and
- 2027 forecast financing of a $0.791 million credit.[59]

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57 FEI Annual Review for 2025 and 2026 Delivery Rates Compliance Filing dated December 9, 2025, Appendix A2, Section 11 – 2026, Schedule 12, Line 3, Column 2.

58 FEI Annual Review for 2025 and 2026 Delivery Rates Compliance Filing dated December 9, 2025, Appendix A2, Section 11 – 2026, Schedule 12, Line 3, Column 4.

59 Section 11, Schedule 12, Line 3, Column 4.

Table 12-3: 2026 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2026 Approved	2026 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (822.807)	$ (820.913)	$ 1.894
3	Commercial (Rate 2, 3, 23)	(400.404)	(391.490)	8.914
4	Industrial (All Others)	(164.508)	(187.155)	(22.647)
5				
6	**Net O&M Expense**			
7	Pension & OPEB	5.725	5.725	-
8	Insurance	12.748	11.816	(0.932)
9	Integrity O&M	12.000	12.900	0.900
10	AMI Flowthrough O&M	25.578	26.334	0.756
11	BCUC Fees	8.208	7.642	(0.566)
12	RNG O&M	7.946	7.777	(0.169)
13	Renewable Gas Development	5.084	5.400	0.316
14	NGT O&M	2.994	2.934	(0.060)
15	Variable LNG Production	11.038	13.260	2.222
16	O&M transferred to RNG Account	(7.946)	(7.777)	0.169
17	Capitalized Overhead	(60.237)	(60.237)	-
18				
19	**Depreciation and Amortization**			
20	Amortization of Deferrals	179.856	179.856	-
21	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
23				
24	**Total Property Taxes**	88.576	95.026	6.450
25				
26	**Other Revenues**			
27	SCP Third Party Revenue	(13.284)	(13.284)	-
28	NGT Tanker Rental Revenue	(1.067)	(0.970)	0.097
29	RNG Other Revenue	(7.592)	(7.358)	0.234
30	LNG Capacity Assignment	(18.039)	(18.039)	-
31	CNG & LNG Service Revenues	(2.443)	(2.226)	0.217
32				
33	**Interest Expense**			
34	Long-term debt interest expense variance	172.987	164.495	(8.492)
35	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Short-term debt rate variance	-	(0.146)	(0.146)
37	Short-term debt volume variance from long-term debt issue variance	-	2.542	2.542
38	Short-term debt timing variance from long-term debt issue timing	-	2.051	2.051
39				
40	**Income Tax Expense**			
41	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
42	Income tax/CCA rate changes	-	(15.930)	(15.930)
43	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.687	1.687
44				
45	**2026 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(20.492)**
46				
47	2025 Ending Deferral Account Balance True-up			(4.715)
48	2026 Financing True-up			(0.931)
49	2027 Financing Addition to Deferral Account			(0.791)
50				
51	**2027 After-Tax Amortization**			**(26.929)**

12.4.2.2.1 2026 PROJECTED FLOW-THROUGH VARIANCES

As shown in Table 12-3 above, the 2026 Projected flow-through variance is a credit of $20.492 million. The variances in each flow-through category are described below.

- The projected variances in delivery margin are primarily due to a favourable industrial margin as a result of higher LNG demand, as described in Section 3.2.4. This favourable industrial margin variance is partially offset by unfavourable commercial and residential margin variances, mainly as a result of lower customers than forecast.
- The flow-through variances related to Other Revenue, O&M and Property Taxes are discussed in Sections 5, 6 and 9, respectively.
- Amortization expense is equal to the approved value.

- The projected interest expense variances are derived from FEI issuing a lower amount of debt and later in the year for both the 2025 and 2026 debt issuances than forecast in the Annual Review for 2025 and 2026 Delivery Rates, and FEI projecting a lower short-term interest rate than the approved short-term interest rate, as discussed in Section 8.
- The income tax variance is derived as 27 percent of the variances described above. This category also includes the flow-through variances related to the additional CCA deduction available for productivity-enhancing assets and the reinstated Accelerated Investment Incentive rules for 2025 and 2026, as discussed in Section 9.3.

An adjustment to include the difference between the projected and final actual amounts for 2026 subject to flow-through will be recorded in the deferral account in 2026 and amortized in 2028 rates.

12.4.2.2.2 2025 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FEI provides a breakout of the 2025 true-up amount of $4.715 million credit in Table 12-4 below, along with an explanation of the variances.

Table 12-4: 2025 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2025 Projected	2025 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (739.716)	$ (738.140)	$ 1.576
3	Commercial (Rate 2, 3, 23)	(356.432)	(351.560)	4.872
4	Industrial (All Others)	(156.919)	(173.231)	(16.313)
5				
6	**Net O&M Expense**			
7	Pension & OPEB	6.790	6.790	-
8	Insurance	12.623	12.585	(0.038)
9	Integrity Digs	9.700	12.027	2.327
10	AMI Flowthrough O&M	24.721	23.408	(1.313)
11	BCUC Fees	8.481	8.481	-
12	RNG O&M	7.278	7.059	(0.219)
13	Renewable Gas Development	4.584	3.840	(0.744)
14	NGT O&M	3.075	3.184	0.109
15	Variable LNG Production	10.688	11.307	0.619
16	O&M transferred to RNG Account	(7.278)	(7.059)	0.219
17	Capitalized Overhead	(58.114)	(58.114)	-
18				
19	**Depreciation and Amortization**			
20	Amortization of Deferrals	138.746	138.746	-
21	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.107	0.107
22	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.029)	(0.029)
23				
24	**Total Property Taxes**	86.927	90.629	3.702
25				
26	**Other Revenues**			
27	SCP Third Party Revenue	(13.284)	(13.284)	-
28	NGT Tanker Rental Revenue	(0.971)	(0.865)	0.106
29	RNG Other Revenue	8.122	8.122	-
30	LNG Capacity Assignment	(18.039)	(18.039)	-
31	CNG & LNG Service Revenues	(2.397)	(2.746)	(0.349)
32				
33	**Interest Expense**			
34	Long-term debt interest expense variance	157.560	155.144	(2.416)
35	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.150	0.150
36	Short-term debt rate variance	-	1.721	1.721
37	Short-term debt volume variance from long-term debt issue variance	-	0.598	0.598
38	Short-term debt timing variance from long-term debt issue timing	-	0.883	0.883
39				
40	**Income Tax Expense**			
41	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.311)	(0.311)
42	Income tax/CCA rate changes	-	-	-
43	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.258	1.258
44				
45	**2025 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(3.485)**
46				
47	2025 Financing True-up			(1.230)
48				
49	**2025 Ending Deferral Account Balance True-up**			**(4.715)**

The variances in delivery margin are primarily due to favourable industrial margin as a result of increased LNG demand, partially offset by an unfavorable commercial margin resulting from fewer large commercial customers than forecast.

The flow-through components of O&M expense are $0.960 million higher than projected, with the main variance related to integrity O&M, which was $2.327 million higher than projected. The variance in integrity O&M was due to an increase in the number of digs (primarily related to required digs in response to ILI data received and analyzed in 2025) and site-specific integrity dig scope factors (primarily related to site access, site management during the dig including for environmental and archaeological reasons, and non-capitalized pipeline repairs) which increased the cost per dig. This variance was partially offset by lower-than-projected AMI O&M ($1.313 million lower than projected), mainly due to the shift in the project start and ramp up periods to initiate billing of network components.

Actual property tax expense was $3.702 million higher than projected due to differences in tax rates and higher distribution and transmission pipeline assessments. The 2025 Projected amounts were calculated using actual 2024 assessment values and actual 2023 tax rates as a baseline to estimate taxes in 2025.

The flow-through components of Other Revenue were $0.243 million higher than projected, with the main variance related to CNG & LNG Service Revenue, which was $0.349 million higher than projected. The variance in CNG & LNG Service Revenue was mainly due to higher CNG station demand than forecast.

The variance between the actual (4.29 percent) and projected (3.58 percent) short-term debt interest rates results in an amount to be recovered from customers of $1.721 million, shown on Line 36 of Table 12-4 above. The net variance of $1.481 million recoverable from customers on Lines 37 and 38 of Table 12-4 is due to a lower amount of long-term debt issued and later in the year than projected, resulting in a higher short-term debt balance than projected. The long-term debt variance of $2.416 million refundable to customers on Line 34 of Table 12-4 is due to the same reasons.

The unfavourable income tax variance of $1.258 million is calculated as 27 percent of the variances.

The combined favourable variance of $0.083 million related to depreciation/CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts shown on Lines 21, 22, 35 and 41, respectively, in Table 12-4 was derived by comparing the actual 2025 cost of service impacts to the forecast amounts. Although multiple projects contributed to the variance, the majority of the favourable variance is attributable to the Clean Growth Initiative assets and the IGU and CTS TIMC Projects.

12.5 *SUMMARY*

FEI has not identified any exogenous factors and no new accounting policy changes are required to be implemented under US GAAP for 2027. FEI is not seeking approval of any new non-rate base deferral accounts but is seeking approval to record $2.740 million of actual flotation costs incurred for the 2026 equity issuance in the previously approved Flotation Costs deferral account. The Flow-through deferral account includes an overall credit of $26.929 million to be returned to customers in 2027 delivery rates, primarily due to favourable delivery margin from higher LNG demand and lower income tax expenses due to deductible flow-through CCA.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

Under the RSF, SQIs are used to monitor the Company's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the RSF Decision, the BCUC approved a balanced set of SQIs for FEI, covering safety, responsiveness to customer needs, and reliability. The BCUC also approved the introduction of five energy transition informational indicators to the suite of SQIs. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Ten of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In this section, FEI reports on its 2025 and June 2026 year-to-date (YTD) performance as measured against the SQI benchmarks and thresholds. In 2025, for the eight SQIs with benchmarks, six performed at or better than the approved benchmarks, with two SQIs (Emergency Response Time and First Contact Resolution) below their respective benchmarks but above the thresholds. Regarding the informational indicators, the performance generally remains at a level consistent with prior years. In 2026 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2020-2024 MRP term, FEI has provided 2025 and year-to-date 2026 SQI results in this Annual Review.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's Actual 2025 and June 2026 YTD performance to the approved benchmarks and thresholds. The Actual 2025 and June 2026 YTD results are also provided for the informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2025 Results	2026 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	96.6%	96.7%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	97.8%	97.0%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<= 1.64	2.21	1.37	1.34

Performance Measure	Description	Benchmark	Threshold	2025 Results	2026 June YTD Results
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 6	10	5	4
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	75%	76%
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	2.28	2.07
Meter Reading Completion	Informational indicator – number of scheduled meters that were read	-	-	95%	94.3%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	70%	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	95.1%	98.6%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.6	8.6
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	56	42
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	0	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	-	-	0.0038	0.0021
Energy Transition SQIs					
Scope 1 Emissions	Informational indicator – total direct GHG emissions from FEI owned or controlled sources ($MtCO_2e$)	-	-	0.17	Not available
Scope 3 Emissions	Informational indicator – total annual BC emissions resulting from customers' combustion gas delivered by FEI sources ($MtCO_2e$)	-	-	10.6	5.8

Performance Measure	Description	Benchmark	Threshold	2025 Results	2026 June YTD Results
Renewable and Lower Carbon Energy Supply Volume	Informational indicator – acquired annual Renewable Gas and Lower Carbon Energy supply (TJ)	-	-	4,159	2,466
	Informational indicator – Renewable and Lower Carbon Energy supply as % of total gas consumed by customers			1.92%	2.14%
Natural Gas for Transportation Volume	Informational indicator – total gas consumed by CNG and LNG customers (TJ)	-	-	7,749	6,183
Demand Side Management Energy Savings	Informational indicator – measure of lifetime gas savings from conservation and energy management programs (TJ)	-	-	11,982	Not available

In the following sections, FEI reviews each SQI's year-to-date performance in 2025 and 2026. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

This SQI measures the utility's responsiveness to on average 24,000 annual emergency events that include gas odour calls, carbon monoxide calls, house fires and hit lines. It is calculated as:

$$\frac{\text{Number of emergency calls responded to within one hour}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events, available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2025 result was 96.6 percent, which is below the benchmark but above the threshold. The June 2026 YTD performance is 96.7 percent, which is also below the benchmark but above the threshold.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-2: Historical Emergency Response Time

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Results	97.7%	97.7%	97.7%	97.5%	97.5%	96.6%	96.7
Benchmark	97.7%						
Threshold	96.2%						

13.2.1.2 Telephone Service Factor (Emergency)

This indicator measures the percentage of emergency calls answered within 30 seconds and is calculated as:

$$\frac{\text{Number of emergency calls answered within 30 seconds}}{\text{Number of emergency calls received}}$$

The telephone service factor (TSF) is a measure of how well the Company can balance costs and service levels, with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include the volume of inbound calls received and the resources available to answer those calls. Staffing is matched to the calls forecast based on historical data in order to reach the service level benchmark desired.

The 2025 result was 97.8 percent, which is better than the benchmark of 95 percent. The June 2026 YTD performance is 97.0 percent which is also better than the benchmark.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-3: Historical TSF (Emergency) Results

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Results	96.9%	96.9%	97.1%	97.8%	97.4%	97.8%	97.0%
Benchmark	95.0%						
Threshold	92.8%						

13.2.1.3 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2025 (three-year rolling average) result was 1.37, which is better than the benchmark. The 2025 annual AIFR was 1.24, which reflected 10 Medical Treatments and 13 Lost Time Injuries.

The June 2026 YTD performance (three-year rolling average) result is 1.34 which is better than the benchmark. The June 2026 YTD performance (annual) is 1.46 and reflects 8 Medical Treatments and 6 Lost Time Injuries.

Strengthening the safety culture continues to be a key driver for FEI, building on the commitment to learn from safety events, proactively identify safety hazards, assess risk and continually improve the Company's safety management system through the implementation and sustainment of robust safety defences and controls.

FEI continues to seek opportunities to improve the AIFR through its ongoing commitment to proactive hazard mitigation, particularly regarding manual labour tasks, safe handling procedures, ergonomics, and slip/trip/fall prevention. FEI has adopted multiple mitigation measures, including enhanced safe work planning, task-specific training and education across areas of the business that have been identified as having a higher risk of injury, additional ergonomic programs/assessments, injury prevention strategies, and a range of technology solutions.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	1.43	1.99	1.36	1.35	1.51	1.24	1.46
Three year rolling average	1.66	1.75	1.59	1.58	1.41	1.37	1.34
Benchmark	2.08					1.64	
Threshold	2.95					2.21	

13.2.1.4 Public Contact with Gas Lines

This metric measures the overall effectiveness of the Company's efforts to minimize damage to the gas system through public awareness, which is designed to reduce interruptions and the associated public safety and service issues to customers.

This indicator is calculated as:

Number of Line Damages per 1,000 BC One Calls received

For the purpose of this service quality indicator, the measurement of performance is based on the annual results.

In its Decision on FEI's Annual Review of 2015 Delivery Rates, the BCUC directed FEI to provide the number of line damages and the number of calls to BC One Call in future annual reviews. Therefore, the number of line damages and number of calls to BC One Call are provided in Table 13-5 below.

The 2025 result was 5, which is better than the benchmark. The June 2026 YTD performance is 4, which is also better than the benchmark.

Principal factors influencing results for this metric include economic growth (i.e., construction activity), damage prevention awareness programs, and heightened public awareness created by the BC 1 Call program. The current year result reflects an ongoing positive trend for this metric. Increased awareness through targeted workshops with municipalities and excavating contractors, together with the ongoing execution of the Damage Investigation Program, have contributed to the above-benchmark performance.

The Company continues to take steps to address line damage. FEI continues to have Damage Prevention Investigators focus on repeat damagers and is working with Technical Safety BC and WorkSafeBC to reduce line hits. The 2026 YTD volume of BC One Call tickets (88,778) is reasonably consistent with the most recent three years (i.e., 86,461 for 2025 YTD, 84,880 for 2024 YTD, and 83,923 for 2023 YTD). The hits per 1,000 ticket metric continues to trend in the right direction, indicating the effectiveness of the additional steps FEI is taking to address line damages.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-5: Historical Public Contact with Gas Lines Results

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	7	6	6	5	5	5	4
Benchmark			8			6	
Threshold			12			10	
BC One Call Ticket Volume	141,262	163,584	157,174	158,478	169,425	168,144	88,778
Line Damages	973	1,034	896	844	779	760	322

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FEI. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2025 result was 75 percent, which is below the benchmark but above the threshold. The June 2026 YTD performance is 76 percent, which is also below the benchmark but above the threshold.

The 2025 result was largely impacted early in the year by the Canada Post job action and high bill inquiries. This created challenging and unprecedented volumes due to customers calling multiple times to get account balances, confirm account balances due to invoices being delivered out of sequence, seek clarity on payment amounts and methods, and to request assistance with signing up for paperless billing. This was coupled with increased high bill inquiry calls that highlighted challenging overall economic pressures for customers. FEI supports customers in a variety of ways, including flexible payment options, energy efficiency tips, rebates and programs, and providing customers with information about other resources such as community and government programs that may be available to them.

FEI reviews all survey interactions to identify and action opportunities for learning and development, additional training, improving processes and ensuring that all customer concerns are resolved. FEI expects to remain above threshold and to move closer to the benchmark by the end of 2026.

FEI continues to maintain a high Customer Satisfaction Index as noted in Section 13.2.2.6 below.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-6: Historical First Contact Resolution Levels

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	81%	79%	78%	77%	80%	75%	76%
Benchmark	78%						
Threshold	74%						

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of three or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2025 result was 2.28 which was better than the benchmark of 3.0. The June 2026 YTD result is 2.07 which is also better than the benchmark. No significant issues have arisen in 2025 and 2026.

The 2025 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2025 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	99.69%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=100*(1.05-99.69%)	5.31
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	98.48%	(100%-PA)*100	=(100%-98.48%)*100	1.52
Billing Service Quality Indicator; Target < 3		(Accuracy PA+Timeliness PA+Completion PA)/3	=(5.31+0.00+1.52) / 3	2.28

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-8: Historical Billing Index Results

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	0.62	0.94	1.02	1.38	2.43	2.28	2.07
Benchmark	3.0						
Threshold	5.0						

13.2.2.3 Meter Reading Completion

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

Factors typically influencing this SQI's performance include the resources available, system issues impacting the Company's billing or reading collections systems, weather conditions including road and highway conditions, and traffic related issues.

In the RSF Decision[60], the BCUC approved FEI's proposal to rename this SQI from "Meter Reading Accuracy" to "Meter Reading Completion", and the BCUC approved FEI's request to change this metric to an informational indicator. As such, commencing in 2025, the Meter Reading Completion indicator will no longer be reported against a benchmark and threshold.

The 2025 result was 95 percent and the June 2026 YTD performance is 94.3 percent.

With respect to the transition to automated meters, the June 2026 YTD results include 21,683 automated reads, which is approximately 0.3 percent of the total meters read in 2026. As a result, the relatively small proportion of automated reads has had a 0.02 percent impact on the overall meter reading completion percentage.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

60 Decision and Order G-69-25, p. 60.

Table 13-9: Historical Meter Reading Completion Results

<table>
<tr><th>Description</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th><th>June 2026 YTD</th></tr>
<tr><td>Annual Results</td><td>89%</td><td>88%</td><td>88%</td><td>95%</td><td>95%</td><td>95%</td><td>94.3%</td></tr>
<tr><td>Benchmark</td><td colspan="5">95%</td><td colspan="2">N/A</td></tr>
<tr><td>Threshold</td><td colspan="5">92%</td><td colspan="2">N/A</td></tr>
</table>

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered within 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

Similar to the TSF (Emergency), this is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data to reach the service level benchmark desired. Other factors that can influence the non-emergency TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2025 result was 70 percent which meets the benchmark. The June 2026 YTD performance is also 70 percent. FEI expects to continue to be at the benchmark by the end of 2026.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-10: Historical TSF (Non-Emergency) Results

<table>
<tr><th>Description</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th><th>June 2026 YTD</th></tr>
<tr><td>Annual Results</td><td>70%</td><td>70%</td><td>62%</td><td>71%</td><td>70%</td><td>70%</td><td>70%</td></tr>
<tr><td>Benchmark</td><td colspan="7">70%</td></tr>
<tr><td>Threshold</td><td colspan="7">68%</td></tr>
</table>

13.2.2.5 Meter Exchange Appointments

The Meter Exchange Appointments SQI measures FEI's performance in meeting appointments for meter exchanges (excluding industrial meters). The calculation for percentage meter exchange appointments met is calculated as:

$$\frac{\text{Number of meter exchange appointments met}}{\text{Number of meter exchange appointments made}}$$

Factors influencing results include processes, number of emergencies, weather, and traffic conditions. The processes require the contact centre and operations departments to work closely together to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The 2025 result was 95.1 percent which was slightly better than the benchmark. The June 2025 YTD performance is 98.6 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	98.1%	98.3%	98.5%	99.1%	97.5%	95.1%	98.6%
Benchmark	95.0%						
Threshold	93.8%						

13.2.2.6 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including overall satisfaction, the contact centre, perceived accuracy of meter reading, energy conservation information, and field services. The index includes feedback from both residential and mass market commercial customers. The survey is conducted quarterly, and results are presented as a score out of 10.

The annual CSI score for 2025 and the June 2026 YTD score are 8.6, which is consistent with prior years. Of the five measures that make up the overall customer satisfaction score, the results for 2025 were higher in three areas, static in one area, and lower in one area compared to the annual 2024 scores. The satisfaction scores increased slightly for Overall Satisfaction (from 8.5 to 8.6), Accuracy of Meter Reading (from 8.3 to 8.5) and Energy Conservation Information (from 7.6 to 7.7). The score for the Contact Centre remained static at 8.7, and the Field Services score decreased slightly from 9.2 to 9.1.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	8.7	8.7	8.6	8.5	8.6	8.6	8.6
Benchmark	N/A						
Threshold	N/A						

13.2.2.7 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2025 result was 56 seconds, which was slightly worse (higher) than the 2024 result but better (lower) than the 2020 to 2023 results. The June 2026 YTD performance is 42 seconds. FEI expects this metric to align with the most recent two years' results.

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-13: Average Speed of Answer

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results	72	65	106	65	50	56	42
Benchmark	N/A						
Threshold	N/A						

13.2.3 Reliability Service Quality Indicators

13.2.3.1 Transmission Reportable Incidents

The Transmission Reportable Incidents metric is an informational indicator that measures the number of reportable incidents to outside agencies for transmission assets as defined by the British Columbia Energy Regulator (BCER). The metric is intended to be an indicator of the integrity of the transmission system.

As of October 1, 2014, the Company reports Transmission Reportable Incidents based on the new BCER reporting criteria, including Level 1 (moderate), Level 2 (major), and Level 3 (serious) reportable incidents for both transmission and intermediate pressure assets that operate at a pressure exceeding 100 psi. This includes pipelines, mains, services, stations, LNG plants and compressor stations, but excludes distribution assets that operate below 100 psi.

There were no reportable incidents in 2025 and there have been no reportable incidents thus far in 2026 (June 2026 YTD).

For comparison, the Company's annual results under the 2020 to 2024 MRP, the 2025 results, and the June 2026 YTD performance are provided below.

Table 13-14: Historical Transmission Reportable Incidents

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Annual Results – Level 1	1	0	0	0	0	0	0
Annual Results – Level 2	0	0	3	0	0	0	0
Annual Results – Level 3	0	0	0	0	0	0	0
Benchmark	N/A						
Threshold	N/A						

13.2.3.2 Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator that measures the number of leaks on the distribution system per KM of distribution system mains. The metric is intended to be an indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system is surveyed for leaks, with the number of leaks varying from year to year, depending on the condition of the pipe surveyed.

Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system, as some sections of the pipeline system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline. As the distribution system ages, the expected number of leaks may increase depending on the Company's pipeline renewal/replacement activities. Using newer, more sensitive leak detection technology may also result in more leaks being detected. This new technology has been in use since 2022.

In its Decision on FEI's Annual Review for 2015 Delivery Rates, the BCUC directed FEI to provide a five-year rolling average as follows:

> The Panel agrees with BCSEA that a five-year rolling average of Leaks per KM of Distribution System Mains would be helpful information and directs FEI to provide this information in future annual reviews.

Table 13-15 below provides the historical data for the calculation of the June 2026 YTD five-year rolling average result of 0.0042 calculated using data from January 2022 to June 2026.

Table 13-15: June 2026 Year-to-Date Five-Year Rolling Average

Period	Metric
January – December 2022	0.0058
January – December 2023	0.0055
January – December 2024	0.0040
January – December 2025	0.0038
January – June 2026	0.0021
Five Year Rolling Average	0.0042

The Company's annual results under the 2020 to 2024 MRP, 2025 and June 2026 year to date results are provided below. The five-year average for each year shown is calculated by taking the average of the results of the stated year and the four years prior (e.g., the 2026 five-year average is calculated using 2022 to 2026 annual data). The June 2026 YTD result is 0.0021 and is based on 51 leaks detected year-to-date, which is consistent with the 2025 year-to-date leaks detected (53) and the 2024 year-to-date leaks detected (50) for the similar period. The number of leaks on DP mains will vary from year to year.

Table 13-16: Historical Leaks per KM of Distribution System Mains

Leaks per KM of Distribution System Mains	2020	2021	2022	2023	2024	2025	June 2026 YTD
Leaks	152	131	138	131	98	91	51
Total km	23,460	23,707	23,734	23,913	24,045	24,171	24,248
Leaks per km	0.0065	0.0055	0.0058	0.0055	0.0041	0.0049	0.0021
5 year rolling average	0.0056	0.0058	0.0060	0.0059	0.0055	0.0038	0.0042

13.2.4 Energy Transition Informational Indicators

In accordance with the RSF Decision[61], FEI is reporting on five new informational indicators related to the energy transition during the term of the RSF. These informational indicators, and their definitions, are as follows:

- **Scope 1 Emissions:** Total direct GHG emissions from FEI owned or controlled sources ($MtCO_2e$).
- **Scope 3 Emissions:** Total annual BC emissions resulting from customers' combustion gas delivered by FEI sources ($MtCO_2e$).
- **Renewable and Lower Carbon Energy Supply:** Acquired annual renewable and lower carbon energy supply (TJ) and the percentage of renewable and lower carbon energy

[61] RSF Decision and Order G-169-25, pp. 65-66.

supply in FEI's total gas supply mix, as well as the mix of renewable and lower carbon gas sources.

- **Natural Gas for Transportation Volume:** Total gas consumed by CNG and LNG customers (TJ).
- **Demand Side Management Energy Savings:** Measure lifetime gas savings from conservation and energy management programs (TJ).

FEI provides further discussion and the annual results of each indicator in the subsections below.

13.2.4.1 Scope 1 Emissions

Scope 1 emissions, as defined under the Greenhouse Gas Protocol Corporate Accounting and Reporting Standards, are direct emissions from owned or controlled sources. This includes externally verified Scope 1 GHG emissions as reported to the BC Ministry of Environment for FEI and its LNG operations.

FEI reports on direct GHG emissions (Scope 1) from its gas operations, third-party gas line damage incidents, RNG processing facilities, FEI fleet vehicles, and gas for comfort heating for FEI facilities. Annual variations are linked to the overall gas delivered to customers due to variations in weather and other factors, including planned and unplanned methane releases.

In 2025, FEI's direct emissions were 0.17 $MtCO_2e$, which were primarily project-driven and associated with compressor station operations, with the majority related to work on the EGP Project.

For comparison, the Company's annual results from 2020 through 2025 are provided below.

Table 13-17: Historical Scope 1 Emissions

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Scope 1 Emissions ($MtCO_2e$)	0.14	0.15	0.24	0.15	0.16	0.17	Not available

13.2.4.2 Scope 3 Emissions

In this section, FEI provides the Category 11 Scope 3 emissions, which are the total annual BC GHG emissions resulting from customers' combustion of gas delivered by FEI sources. These are a category of emissions that FEI does not directly control but are related to the energy the Company delivers to customers.

In 2025, the total annual Category 11 Scope 3 emissions were 10.6 $MtCO_2e$.

For comparison, the Company's annual results from 2020 through 2025 and June 2026 year-to-date results are provided below.

Table 13-18: Historical Scope 3 Emissions

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Scope 3 Emissions ($MtCO_2e$)	11.0	11.5	11.6	10.6	10.9	10.6	5.8

13.2.4.3 Renewable and Lower Carbon Energy Supply

The Renewable and Lower Carbon Energy Supply indicator tracks the total volume of renewable and lower carbon energy supply acquired in the calendar year in terajoules (TJ).

In the RSF Decision, the BCUC also directed FEI to include specific reporting on the mix of renewable and lower carbon gas sources, as well as the percentage of these sources in its total gas supply.[62]

In 2025, FEI acquired 4,159 TJ of renewable and lower carbon energy, which is 1.92 percent of FEI's total gas consumed by customers in 2025. The 4,159 TJ was comprised entirely of RNG.

For comparison, the Company's annual results from 2020 through 2025 and June 2026 year-to-date results are provided below.

[62] RSF Decision and Order G-169-25, p. 65.

Table 13-19: Historical Renewable and Lower Carbon Energy Supply

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Renewable and Lower Carbon Energy Supply Volume (TJ)	252	715	2,295	2,778	2,776	4,159	2,466
Total Volume of Gas Consumed by Customers (PJ)	219	228	231	213	220	217	115
Renewable and Lower Carbon Energy Supply as Percentage of Total Gas Consumed by Customers (%)	0.12	0.31	0.99	1.31	1.26	1.92	2.14

13.2.4.4 Natural Gas for Transportation Volumes

FEI is advancing lower- and zero-carbon transportation, including CNG and LNG as replacement fuel for heavy-carbon transport fuels. For this informational indicator, FEI has combined the CNG and LNG volume delivered to the transportation and marine sector into one overall supply metric. This includes the CNG delivered to CNG stations, LNG stations and the LNG used in marine bunkering.

In 2025, FEI delivered 7,749 TJ of Natural Gas for Transportation volume. The increase in volume for 2025 was largely driven by increased demand from the marine bunkering customer segment.

For comparison, the Company's annual results from 2020 through 2025 and June 2026 year-to-date results are provided below.

Table 13-20: Natural Gas for Transportation Volumes

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Total Gas Consumed by CNG and LNG Customers (TJ)	2,413	2,652	3,077	3,117	3,716	7,749	6,183

13.2.4.5 Demand Side Management Energy Savings

The Demand Side Management Energy Savings informational indicator measures the lifetime gas savings from FEI's conservation and energy management (C&EM) programs. These savings are the total reductions that occur over the life of all measures implemented (based on the Net Present Value of gas savings). Lifetime in this context refers to the entire stream of savings from measures supported in each of the years listed and annualizing that to present time to show the total value of the stream of savings. This view of the energy savings most accurately reflects the overall eventual impact of the savings incurred as a result of the measures incented by FEI's DSM programming.

In 2025, the total measure of lifetime gas savings from FEI's C&EM programs was 11,982 TJ.

For comparison, the Company's annual results from 2020 through 2025 are provided below.

Table 13-21: Demand Side Management Energy Savings

Description	2020	2021	2022	2023	2024	2025	June 2026 YTD
Lifetime gas savings from conservation and energy management programs (TJ)	7,937	12,304	10,811	10,104	14,159	11,982	Not available

13.3 *SUMMARY*

FEI's 2025 results and June 2026 year-to-date SQI performance indicate that the Company's overall performance is representative of a high level of service quality. In 2025, for the eight SQIs with benchmarks, six performed at or better than the approved benchmarks, with two SQIs (Emergency Response Time and First Contact Resolution) performing below their respective benchmarks but above the thresholds. Regarding the informational indicators, the performance generally remains at a level consistent with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Appendix A-1

STATISTICS CANADA AND CONFERENCE BOARD OF CANADA REPORTS

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
July 2024	156.4
August 2024	156.2
September 2024	155.8
October 2024	156.2
November 2024	156.3
December 2024	156.1
January 2025	156.0
February 2025	157.6
March 2025	157.8
April 2025	157.8
May 2025	159.0
June 2025	158.8
July 2025	159.1
August 2025	159.0
September 2025	158.8
October 2025	159.4
November 2025	159.5
December 2025	158.7
January 2026	159.1
February 2026	160.3
March 2026	161.7
April 2026	161.7
May 2026	163.6
June 2026	163.3

Table A1-2: Average Weekly Earnings (AWE)

Reference period	
	Dollars
July 2024	1,280.92 B
August 2024	1,284.97 B
September 2024	1,285.71 B
October 2024	1,289.28 B
November 2024	1,290.96 B
December 2024	1,292.51 B
January 2025	1,298.71 B
February 2025	1,299.76 B
March 2025	1,302.42 B
April 2025	1,308.50 B
May 2025	1,294.59 B
June 2025	1,302.31 B
July 2025	1,299.03 B
August 2025	1,302.02 B
September 2025	1,309.68 B
October 2025	1,310.70 B
November 2025	1,320.73 B
December 2025	1,315.46 B
January 2026	1,331.01 B
February 2026	1,349.12 B
March 2026	1,349.57 B
April 2026	1,357.68 B

Table A1-3: Provincial Outlook Long-Term Economic Forecast 2026 and 2027

BRITISH COLUMBIA	2024	2025	2026	2027	2028	2029	2030
Housing Starts Units, Singles, British Columbia	5,550	5,922	5,123	4,772	4,649	4,588	4,504
Percent Change		**6.7%**	**-13.5%**	**-6.8%**	**-2.6%**	**-1.3%**	**-1.8%**
Housing Starts Units, Multiples, British Columbia	40,278	39,568	34,303	32,107	31,165	30,448	29,497
Percent Change		**-1.8%**	**-13.3%**	**-6.4%**	**-2.9%**	**-2.3%**	**-3.1%**
e-data Source: Signal 49 (AKA Conference Board of Canada)							
Data Released: March 27th, 2026							
Data Reveived: April 2nd, 2026							

Appendix A-2

HISTORICAL FORECAST AND CONSOLIDATED TABLES

Appendix A-2

Historical Forecast and Consolidated Tables

Table of Contents

List of Appendices

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historical and Forecast Data
    a. 2016 – 2025 Actual data
    b. 2026 Seed data
    c. 2027 Forecast data
2. Percent Error
    a. 2016 - 2025 Forecast, Actual and percent error

2. HISTORICAL AND FORECAST DATA TABLES

Table A2-1: FEI Customer Counts, Customer Additions, Use per Customer, and Energy[1]

FEI Customer Counts

Rate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026-S	2027-F
RS 1	897,528	910,885	930,142	940,751	953,746	963,987	974,334	985,844	996,178	1,002,255	1,007,518	1,012,435
RS 2	86,074	86,973	88,244	88,686	89,363	89,683	89,976	90,185	92,708	93,003	93,889	94,774
RS 3	5,189	5,441	6,028	6,973	6,805	7,013	7,224	8,849	7,941	7,717	7,768	7,819
RS 23	1,803	1,712	1,648	871	746	697	620	453	376	375	376	378
Industrial	955	976	989	1,020	1,023	1,026	1,050	1,067	1,069	1,101	1,102	1,102
NGT	42	56	41	53	69	74	98	101	101	100	117	117
Total	991,591	1,006,043	1,027,092	1,038,354	1,051,752	1,062,480	1,073,302	1,086,499	1,098,373	1,104,551	1,110,770	1,116,625

FEI Customer Additions

Rate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026-S	2027-F
RS 1	11,359	13,357	19,257	10,609	12,995	10,241	10,347	9,674	10,334	6,077	5,263	4,917
RS 2	998	899	1,271	442	677	320	293	(236)	2,523	295	886	886
RS 3	(112)	252	587	945	(168)	208	211	1,609	(908)	(224)	51	51
RS 23	79	(91)	(64)	(777)	(125)	(49)	(77)	(167)	(77)	(1)	1	1
Industrial	(21)	21	13	31	3	3	24	17	2	32	1	0
NGT	11	14	(15)	12	16	5	24	3	0	(1)	17	0
Total	12,314	14,452	21,049	11,262	13,398	10,728	10,822	10,900	11,874	6,178	6,219	5,855

FEI Normalized Use Per Customer (GJ)

Rate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026-S	2027-F
RS 1	87.5	85.8	85.1	82.4	86.2	85.7	83.0	81.8	80.4	78.6	79.2	79.2
RS 2	339.1	336.8	332.5	318.1	322.2	328.1	334.9	326.5	313.5	317.5	315.0	313.7
RS 3	3,720.9	3,692.5	3,549.8	3,516.7	3,660.3	3,702.5	3,737.6	3,513.9	3,558.1	3,692.6	3,643.5	3,651.6
RS 23	5,279.0	5,360.5	5,344.9	5,051.3	5,440.7	5,724.3	5,818.1	5,764.4	6,236.1	5,688.6	6,117.5	6,465.7

FEI Energy (PJ)(1)

Rate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026-S	2027-F
RS 1	77.9	77.5	78.3	77.0	81.6	82.2	80.4	80.3	79.8	78.5	79.6	80.0
RS 2	29.0	29.1	29.1	28.1	28.7	29.3	30.0	29.3	28.7	29.5	29.4	29.6
RS 3	19.4	19.7	20.9	22.5	24.6	25.7	26.7	29.2	29.6	28.9	28.2	28.5
RS 23	9.3	9.5	9.0	7.3	4.6	4.2	3.9	3.4	2.7	2.1	2.3	2.4
Industrial	83.7	87.4	88.4	91.5	89.5	90.8	77.6	72.5	75.6	71.0	71.0	70.1
NGT	1.3	1.8	1.6	2.6	2.6	3.0	3.2	3.3	3.9	8.0	7.7	7.7
Total	220.6	225.0	227.3	229.0	231.7	235.2	221.8	218.0	220.3	218.1	218.2	218.2

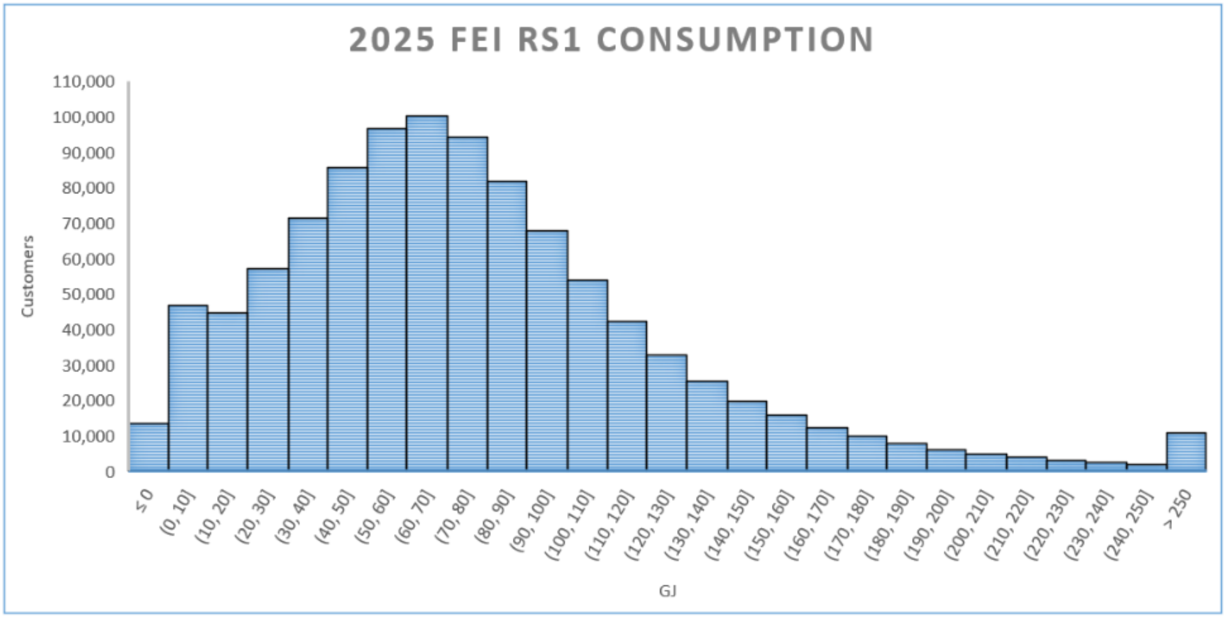
Note FTN included 2023 and beyond

Table A2-2: FEI 2027F Industrial Forecast Demand by Region[2]

Region Group	2027 Forecast Demand by Region (PJ)
Mainland	63.5
Vancouver Island	6.5
Whistler	0.1
Grand Total	**70.1**

1 Historical industrial tables do not include Burrard Thermal demand.
2 Does not include NGT forecast demand.

Figure A2-1: FEI Residential Customers Normalized UPC in 2025



3. PERCENT ERROR DATA TABLES

In the data tables presented below, FEI provides 10 years of historical actual demand, forecast demand and percent error for each customer class and service area and on a consolidated (or amalgamated) basis, for total demand, total net customers, net customer additions and use per customer. The data tables are also provided as a fully-functional Excel file in Appendix A2-1.

Percent error is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

$$PE_t = \left(\frac{Y_t - F_t}{Y_t}\right) \times 100$$

Where F_t is the forecast at time t and Y_t is the actual value at time t.

The tables provided below present the historical data in amalgamated form, unless specifically identified for a particular region.

3.1 AMALGAMATED NET CUSTOMERS

FEI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	892,830	909,727	916,365	934,804	950,330	958,899	974,625	981,299	994,950	1,006,183
Actual	897,528	910,885	930,142	940,751	953,746	963,987	974,334	985,844	996,178	1,002,255
Error = (ACT-FCST)	4,698	1,158	13,777	5,947	3,416	5,088	(291)	4,545	1,228	(3,928)
Percent Error = (Error/ACT)	0.5%	0.1%	1.5%	0.6%	0.4%	0.5%	0.0%	0.5%	0.1%	-0.4%

FEI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	85,667	87,712	88,494	89,203	89,558	90,430	90,956	91,112	91,271	93,380
Actual	86,074	86,973	88,244	88,686	89,363	89,683	89,976	90,185	92,708	93,003
Error = (ACT-FCST)	407	(739)	(250)	(517)	(195)	(747)	(980)	(927)	1,437	(377)
Percent Error = (Error/ACT)	0.5%	-0.8%	-0.3%	-0.6%	-0.2%	-0.8%	-1.1%	-1.0%	1.6%	-0.4%

FEI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	5,035	5,354	5,223	5,623	7,221	7,469	7,034	7,055	7,237	8,310
Actual	5,189	5,441	6,028	6,973	6,805	7,013	7,224	8,849	7,941	7,717
Error = (ACT-FCST)	154	87	805	1,350	(416)	(456)	190	1,794	704	(593)
Percent Error = (Error/ACT)	3.0%	1.6%	13.4%	19.4%	-6.1%	-6.5%	2.6%	20.3%	8.9%	-7.7%

FEI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	1,670	1,760	1,934	1,744	906	941	782	703	624	394
Actual	1,803	1,712	1,648	871	746	697	620	453	376	375
Error = (ACT-FCST)	133	(48)	(286)	(873)	(160)	(244)	(162)	(250)	(248)	(19)
Percent Error = (Error/ACT)	7.4%	-2.8%	-17.4%	-100.2%	-21.4%	-35.0%	-26.1%	-55.2%	-66.1%	-5.0%

FEI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Large Commercial										
Forecast	6,705	7,114	7,157	7,367	8,127	8,410	7,816	7,758	7,861	8,704
Actual	6,992	7,153	7,676	7,844	7,551	7,710	7,844	9,302	8,317	8,092
Error = (ACT-FCST)	287	39	519	477	(576)	(700)	28	1,544	456	(612)
Percent Error = (Error/ACT)	4.1%	0.5%	6.8%	6.1%	-7.6%	-9.1%	0.4%	16.6%	5.5%	-7.6%

*2023 (and beyond) Actual and Forecast included FTN

3.2 AMALGAMATED NET CUSTOMER ADDITIONS

FEI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	9,461	11,522	9,141	10,724	9,579	8,569	10,096	7,171	9,903	10,005
Actual	11,359	13,357	19,257	10,609	12,995	10,241	10,347	9,674	10,334	6,077
Error = (ACT-FCST)	1,898	1,835	10,116	(115)	3,416	1,672	251	2,503	431	(3,928)
Percent Error = (Error/ACT)	16.7%	13.7%	52.5%	-1.1%	26.3%	16.3%	2.4%	25.9%	4.2%	-64.6%

FEI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	1,026	1,318	1,210	1,115	872	872	797	472	425	672
Actual	998	899	1,271	442	677	320	293	(236)	2,523	295
Error = (ACT-FCST)	(28)	(419)	61	(673)	(195)	(552)	(504)	(708)	2,098	(377)
Percent Error = (Error/ACT)	-2.8%	-46.6%	4.8%	-152.3%	-28.8%	-172.5%	-171.9%	300.1%	83.2%	-127.7%

FEI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	(51)	26	19	91	248	248	115	10	(2)	369
Actual	(112)	252	587	945	(168)	208	211	1,609	(908)	(224)
Error = (ACT-FCST)	(61)	226	568	854	(416)	(40)	96	1,599	(906)	(593)
Percent Error = (Error/ACT)	54.5%	89.7%	96.8%	90.4%	247.6%	-19.2%	45.6%	99.4%	99.8%	264.8%

FEI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	30	18	66	16	35	35	18	3	2	18
Actual	79	(91)	(64)	(777)	(125)	(49)	(77)	(167)	(77)	(1)
Error = (ACT-FCST)	49	(109)	(130)	(793)	(160)	(84)	(95)	(170)	(79)	(19)
Percent Error = (Error/ACT)	62.0%	119.8%	203.1%	102.1%	128.0%	171.4%	123.3%	101.8%	102.9%	1893.3%

*2023 (and beyond) Actual and Forecast included FTN

1 ## 3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1											
Forecast	83.1	81.6	82.2	89.1	87.0	85.7	83.1	84.1	84.8	84.2	80.4
Actual	84.4	87.5	85.8	85.1	82.4	86.2	85.7	83.0	81.8	80.4	78.6
Error = (ACT-FCST)	1.3	5.9	3.7	(4.0)	(4.6)	0.4	2.6	(1.1)	(2.9)	(3.8)	(1.9)
Percent Error = (Error/ACT)	1.5%	6.7%	4.3%	-4.7%	-5.6%	0.5%	3.1%	-1.3%	-3.6%	-4.8%	-2.4%

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2											
Forecast	333.7	329.5	328.4	345.2	341.3	324.9	321.8	320.4	321.7	326.8	317.3
Actual	332.6	339.1	336.8	332.5	318.1	322.2	328.1	334.9	326.5	313.5	317.5
Error = (ACT-FCST)	(1.1)	9.6	8.3	(12.7)	(23.2)	(2.7)	6.3	14.6	4.7	(13.3)	0.2
Percent Error = (Error/ACT)	-0.3%	2.8%	2.5%	-3.8%	-7.3%	-0.8%	1.9%	4.3%	1.4%	-4.2%	0.1%

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3											
Forecast	3,754	3,593	3,488	3,842	3,831	3,648	3,551	3,557	3,652.0	3,728.0	3,662.8
Actual	3,587	3,721	3,692	3,550	3,517	3,660	3,703	3,737.6	3,513.9	3,558.1	3,692.6
Error = (ACT-FCST)	(167)	128	205	(292)	(314)	12	151	181	(138)	(169.9)	29.8
Percent Error = (Error/ACT)	-4.7%	3.4%	5.5%	-8.2%	-8.9%	0.3%	4.1%	4.8%	-3.9%	-4.8%	0.8%

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23											
Forecast	5,309	5,382	5,227	5,399	5,492	5,480	5,278	5,365	5,570	5,835.5	5,946.1
Actual	5,174	5,279	5,361	5,345	5,051	5,441	5,724	5,818	5,764	6,236.1	5,688.6
Error = (ACT-FCST)	(135)	(103)	133	(54)	(440)	(39)	447	453	194	400.6	(257.5)
Percent Error = (Error/ACT)	-2.6%	-2.0%	2.5%	-1.0%	-8.7%	-0.7%	7.8%	7.8%	3.4%	6.4%	-4.5%

2 *2023 (and beyond) Actual and Forecast included FTN

3.4 AMALGAMATED DEMAND

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	72.5	74.3	81.2	80.8	81.1	79.3	81.5	82.9	83.4	80.5
Actual	77.9	77.5	78.3	77.0	81.6	82.2	80.4	80.3	79.8	78.5
Error = (ACT-FCST)	5.4	3.3	(2.9)	(3.7)	0.5	2.9	(1.1)	(2.6)	(3.6)	(2.0)
Percent Error = (Error/ACT)	7.0%	4.2%	-3.7%	-4.9%	0.6%	3.5%	-1.3%	-3.2%	-4.5%	-2.5%
Abs. Percent Error	7.0%	4.2%	3.7%	4.9%	0.6%	3.5%	1.3%	3.2%	4.5%	2.5%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	28.0	28.5	30.3	30.2	28.9	28.9	29.0	29.2	29.7	29.4
Actual	29.0	29.1	29.1	28.1	28.7	29.3	30.0	29.3	28.7	29.5
Error = (ACT-FCST)	1.0	0.6	(1.2)	(2.1)	(0.2)	0.4	1.0	0.1	(1.0)	0.0
Percent Error = (Error/ACT)	3.4%	2.0%	-4.3%	-7.4%	-0.8%	1.2%	3.5%	0.5%	-3.3%	0.2%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	18.1	18.7	20.1	21.5	25.2	26.2	24.9	25.7	27.0	29.6
Actual	19.4	19.7	20.9	22.5	24.6	25.7	26.7	29.2	29.6	28.9
Error = (ACT-FCST)	1.3	1.0	0.9	1.0	(0.6)	(0.5)	1.8	3.4	2.6	(0.7)
Percent Error = (Error/ACT)	6.7%	5.2%	4.1%	4.3%	-2.4%	-1.8%	6.8%	11.8%	8.9%	-2.4%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	9.0	9.2	10.3	9.6	4.8	4.9	4.1	3.9	3.6	2.3
Actual	9.3	9.5	9.0	7.3	4.6	4.2000	3.9	3.4	2.7	2.1
Error = (ACT-FCST)	0.3	0.4	(1.3)	(2.3)	(0.2)	(0.7)	(0.2)	(0.5)	(0.9)	(0.1)
Percent Error = (Error/ACT)	3.2%	3.9%	-13.9%	-31.3%	-5.2%	-16.1%	-4.5%	-16.4%	-34.3%	-6.8%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commercial										
Forecast	55.1	56.4	60.7	61.3	59.0	60.0	58.0	58.8	60.3	61.3
Actual	57.7	58.3	59.0	57.9	57.9	59.200	60.6	61.9	61.0	60.5
Error = (ACT-FCST)	2.6	2.0	(1.6)	(3.4)	(1.1)	(0.8)	2.7	3.0	0.8	(0.8)
Percent Error = (Error/ACT)	4.5%	3.4%	-2.8%	-5.9%	-1.9%	-1.3%	4.4%	4.9%	1.2%	-1.3%
Abs. Percent Error	4.5%	3.4%	2.8%	5.9%	1.9%	1.3%	4.4%	4.9%	1.2%	1.3%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate 5										
Forecast	2.2	2.2	2.5	2.9	7.6	7.6	8.7	9.4	10.2	14.3
Actual	2.4	2.8	3.8	4.8	8.1	9.1	9.8	10.3	13.3	14.4
Error = (ACT-FCST)	0.3	0.7	1.3	1.9	0.5	1.6	1.1	0.9	3.1	0.1
Percent Error = (Error/ACT)	11%	23%	34%	40%	6%	17%	11%	9%	24%	0%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate 25										
Forecast	13.8	13.8	14.4	14.8	10.3	10.8	9.9	9.2	8.7	6.9
Actual	13.9	14.5	13.9	13.2	9.9	9.324	9.1	7.9	7.3	6.8
Error = (ACT-FCST)	0.1	0.7	(0.5)	(1.7)	(0.4)	(1.5)	(0.8)	(1.3)	(1.3)	(0.2)
Percent Error = (Error/ACT)	1%	5%	-3%	-13%	-4%	-16%	-9%	-17%	-18%	-2%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate 22										
Forecast	36.3	38.2	38.5	43.3	41.0	37.4	37.8	39.5	37.3	34.1
Actual	40.5	40.9	42.0	43.3	39.0	40.1	38.6	38.8	38.1	32.2
Error = (ACT-FCST)	4.2	2.6	3.5	0.1	(2.0)	2.7	0.8	(0.7)	0.8	(1.9)
Percent Error = (Error/ACT)	10%	6%	8%	0%	-5%	7%	2%	-2%	2%	-6%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate 27										
Forecast	6.5	6.4	7.3	7.9	4.7	4.8	4.5	4.3	3.9	3.1
Actual	6.8	7.5	6.2	5.9	4.6	4.4365	4.3	3.9	3.4	3.2
Error = (ACT-FCST)	0.3	1.1	(1.1)	(2.0)	(0.1)	(0.4)	(0.2)	(0.4)	(0.5)	0.1
Percent Error = (Error/ACT)	4%	14%	-17%	-34%	-1%	-8%	-4%	-10%	-14%	3%

FEI Demand,PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Industrial* *										
Forecast	78.1	82.1	84.3	90.6	91.9	87.8	88.9	73.3	71.7	72.9
Actual	83.7	87.4	88.4	91.5	89.5	90.8	77.6	72.5	75.6	71.0
Error = (ACT-FCST)	5.6	5.3	4.2	0.9	(2.4)	2.9	(11.3)	(0.9)	3.9	(1.8)
Percent Error = (Error/ACT)	6.7%	6.0%	4.7%	1.0%	-2.7%	3.2%	-14.6%	-1.2%	5.1%	-2.6%
Abs. Percent Error	6.7%	6.0%	4.7%	1.0%	2.7%	3.2%	14.6%	1.2%	5.1%	2.6%

FEI Demand,PJ**	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
FEI										
Forecast	205.7	212.8	226.2	232.6	232.0	227.1	228.4	215.1	215.4	214.7
Actual	219.3	223.3	225.8	226.4	229.0	232.2	218.6	214.6	216.4	210.1
Error = (ACT-FCST)	13.6	10.5	(0.4)	(6.2)	(2.9)	5.1	(9.7)	(0.5)	1.0	(4.6)
Percent Error = (Error/ACT)	6.2%	4.7%	-0.2%	-2.7%	-1.3%	2.2%	-4.5%	-0.2%	0.5%	-2.2%
Abs. Percent Error	6.2%	4.7%	0.2%	2.7%	1.3%	2.2%	4.5%	0.2%	0.5%	2.2%

*2023 (and beyond) Actual and Forecast included FTN
**Excld NGT and Burrard

*Excld NGT and Burrard

3.5 MAINLAND NET CUSTOMERS

Mainland Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	787,836	799,732	803,319	813,959	823,255	828,146	839,746	838,999	851,599	861,704
Actual	790,562	798,917	811,696	817,817	826,142	831,178	838,403	845,895	853,935	858,394
Error = (ACT-FCST)	2,726	(815)	8,377	3,858	2,887	3,032	(1,343)	6,896	2,336	(3,310)
Percent Error = (Error/ACT)	0.3%	-0.1%	1.0%	0.5%	0.3%	0.4%	-0.2%	0.8%	0.3%	-0.4%

Mainland Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	76,166	77,597	78,228	78,767	79,027	79,703	80,203	79,856	80,029	81,800
Actual	76,326	77,047	78,044	78,351	78,941	79,108	79,358	79,003	81,253	81,475
Error = (ACT-FCST)	160	(550)	(184)	(416)	(86)	(595)	(845)	(853)	1,224	(325)
Percent Error = (Error/ACT)	0.2%	-0.7%	-0.2%	-0.5%	-0.1%	-0.8%	-1.1%	-1.1%	1.5%	-0.4%

Mainland Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	4,497	4,667	4,608	5,029	6,545	6,799	6,239	6,224	6,400	7,424
Actual	4,605	4,867	5,478	6,291	6,046	6,243	6,443	7,895	7,091	6,901
Error = (ACT-FCST)	108	200	870	1,262	(499)	(556)	204	1,671	691	(523)
Percent Error = (Error/ACT)	2.3%	4.1%	15.9%	20.1%	-8.3%	-8.9%	3.2%	21.2%	9.7%	-7.6%

Mainland Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	1,582	1,609	1,669	1,562	836	872	742	664	590	381
Actual	1,614	1,546	1,458	800	708	661	587	438	364	364
Error = (ACT-FCST)	32	(63)	(211)	(762)	(128)	(211)	(155)	(226)	(226)	(17)
Percent Error = (Error/ACT)	2.0%	-4.1%	-14.5%	-95.3%	-18.1%	-31.9%	-26.4%	-51.6%	-62.0%	-4.8%

3.6 MAINLAND NET CUSTOMER ADDITIONS

Mainland Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	6,863	8,250	6,203	6,756	5,438	4,891	6,622	3,574	6,968	7,769
Actual	7,648	8,355	12,779	6,121	8,325	5,036	7,225	7,492	8,040	4,459
Error = (ACT-FCST)	785	105	6,576	(635)	2,887	145	603	3,918	1,072	(3,310)
Percent Error = (Error/ACT)	10.3%	1.3%	51.5%	-10.4%	34.7%	2.9%	8.3%	52.3%	13.3%	-74.2%

Mainland Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	851	1,072	951	860	676	676	631	355	336	547
Actual	875	721	997	307	590	167	250	(355)	2,250	222
Error = (ACT-FCST)	24	(351)	46	(553)	(86)	(509)	(381)	(710)	1,914	(325)
Percent Error = (Error/ACT)	2.7%	-48.7%	4.6%	-180.1%	-14.6%	-304.8%	-152.5%	199.9%	85.1%	-146.5%

Mainland Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	(64)	(1)	2	81	254	254	97	(13)	(22)	333
Actual	(66)	262	611	813	(245)	197	200	1,452	(804)	(190)
Error = (ACT-FCST)	(2)	263	609	732	(499)	(57)	103	1,465	(782)	(523)
Percent Error = (Error/ACT)	3.0%	100.4%	99.7%	90.0%	203.7%	-28.9%	51.7%	100.9%	97.3%	275.2%

Mainland Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	30	18	28	8	36	36	17	2	1	17
Actual	41	(68)	(88)	(658)	(92)	(47)	(74)	(149)	-74	0
Error = (ACT-FCST)	11	(86)	(116)	(666)	(128)	(83)	(91)	(151)	(75)	(17)
Percent Error = (Error/ACT)	26.8%	126.5%	131.8%	101.2%	139.1%	176.6%	123.0%	101.0%	101.8%	

1 ## 3.7 MAINLAND NORMALIZED USE PER CUSTOMER

Mainland UPC GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	86.3	86.2	93.5	91.5	90.8	88.2	89.2	89.9	89.4	85.7
Actual	92.0	90.4	89.7	87.1	91.1	90.8	88.1	87.1	85.5	83.6
Error = (ACT-FCST)	5.7	4.2	(3.8)	(4.5)	0.3	2.6	(1.0)	(2.8)	(3.9)	(2.1)
Percent Error = (Error/ACT)	6.2%	4.6%	-4.2%	-5.1%	0.4%	2.8%	-1.1%	-3.3%	-4.6%	-2.5%

Mainland UPC GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	329	327	345	339	324	320	320	322	326.3	316.1
Actual	338	335	329	316	322	327	334	326	311.9	315.7
Error = (ACT-FCST)	10	8	(15)	(23)	(2)	7	13	4	(14)	(0)
Percent Error = (Error/ACT)	2.8%	2.4%	-4.6%	-7.3%	-0.6%	2.2%	4.0%	1.3%	-4.6%	-0.1%

Mainland UPC GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	3,537	3,517	3,770	3,746	3,640	3,501	3,591	3,671	3,739	3,668
Actual	3,658	3,625	3,477	3,468	3,682	3,704	3,728	3,504	3,547	3,689
Error = (ACT-FCST)	121	108	(293)	(278)	42	202	137	(167)	(192)	20
Percent Error = (Error/ACT)	3.3%	3.0%	-8.4%	-8.0%	1.1%	5.5%	3.7%	-4.8%	-5.4%	0.5%

Mainland UPC GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	5,348	5,197	5,416	5,521	5,537	5,362	5,418	5,579	5,831	5,928
Actual	5,304	5,388	5,357	5,127	5,497	5,699	5,811	5,751	6,216	5,668
Error = (ACT-FCST)	(44)	191	(59)	(394)	(41)	336	393	172	386	(260)
Percent Error = (Error/ACT)	-0.8%	3.5%	-1.1%	-7.7%	-0.7%	5.9%	6.8%	3.0%	6.2%	-4.6%

2

1 ## 3.8 MAINLAND NORMALIZED DEMAND

Mainland Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	67.7	68.6	74.8	74.2	74.5	72.8	74.6	75.3	75.9	73.5
Actual	72.3	71.8	72.2	70.9	74.9	75.2	73.6	73.3	72.8	71.6
Error = (ACT-FCST)	4.6	3.2	(2.6)	(3.2)	0.4	2.4	(1.0)	(2.0)	(3.1)	(1.9)
Percent Error = (Error/ACT)	6.4%	4.5%	-3.6%	-4.6%	0.5%	3.2%	-1.4%	-2.7%	-4.2%	-2.6%
Abs. Percent Error	6.4%	4.5%	3.6%	4.6%	0.5%	3.2%	1.4%	2.7%	4.2%	2.6%

Mainland Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	24.9	25.2	26.7	26.5	25.5	25.4	25.6	25.6	26.0	25.7
Actual	25.6	25.7	25.5	24.7	25.3	25.8	26.4	25.7	25.0	25.7
Error = (ACT-FCST)	0.7	0.5	(1.3)	(1.8)	(0.1)	0.5	0.8	0.1	(0.9)	(0.0)
Percent Error = (Error/ACT)	2.7%	2.0%	-5.0%	-7.3%	-0.5%	1.7%	3.1%	0.4%	-3.8%	0.0%

Mainland Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	16.0	16.4	17.4	18.8	22.6	23.5	22.3	22.9	23.9	26.5
Actual	16.8	17.3	18.5	20.1	22.1	22.9	23.7	25.9	26.3	25.8
Error = (ACT-FCST)	0.8	0.9	1.2	1.3	(0.5)	(0.5)	1.4	3.1	2.4	(0.7)
Percent Error = (Error/ACT)	5.0%	5.4%	6.3%	6.4%	-2.4%	-2.3%	6.0%	11.9%	9.1%	-2.6%

Mainland Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	8.4	8.3	9.0	8.6	4.5	4.6	4.0	3.7	3.4	2.2
Actual	8.4	8.6	8.1	6.6	4.3	4.0	3.7	3.2	2.6	2.1
Error = (ACT-FCST)	-	0.3	(0.8)	(2.0)	(0.2)	(0.6)	(0.2)	(0.5)	(0.8)	(0.1)
Percent Error = (Error/ACT)	0.0%	3.1%	-10.4%	-30.8%	-4.8%	-15.9%	-5.8%	-16.3%	-31.6%	-6.7%

Mainland Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commercial										
Forecast	49.3	49.9	53.1	53.9	52.6	53.4	51.8	52.2	53.4	54.4
Actual	50.8	51.6	52.2	51.3	51.7	52.7	53.8	54.8	54.0	53.5
Error = (ACT-FCST)	1.5	1.7	(0.9)	(2.5)	(0.9)	(0.7)	2.0	2.7	0.6	(0.8)
Percent Error = (Error/ACT)	3.0%	3.3%	-1.8%	-5.0%	-1.6%	-1.4%	3.8%	4.9%	1.2%	-1.6%
Abs. Percent Error	3.0%	3.3%	1.8%	5.0%	1.6%	1.4%	3.8%	4.9%	1.2%	1.6%

2

1 ## 3.9 VANCOUVER ISLAND NET CUSTOMERS

FEVI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	102,458	107,314	110,270	117,957	124,041	127,631	131,838	137,323	138,443	139,414
Actual	104,358	109,259	115,618	119,998	124,627	129,764	132,861	135,000	137,236	138,799
Error = (ACT-FCST)	1,900	1,945	5,348	2,041	586	2,133	1,023	(2,323)	(1,207)	(615)
Percent Error = (Error/ACT)	1.8%	1.8%	4.6%	1.7%	0.5%	1.6%	0.8%	-1.7%	-0.9%	-0.4%

FEVI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	9,209	9,808	9,971	10,131	10,218	10,408	10,443	10,523	10,501	10,830
Actual	9,459	9,629	9,891	10,028	10,117	10,270	10,312	10,444	10,704	10,779
Error = (ACT-FCST)	250	(179)	(80)	(103)	(101)	(138)	(131)	(79)	203	(51)
Percent Error = (Error/ACT)	2.6%	-1.9%	-0.8%	-1.0%	-1.0%	-1.3%	-1.3%	-0.8%	1.9%	-0.5%

FEVI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	479	647	567	539	605	597	720	736	751	785
Actual	531	517	492	613	686	697	711	844	753	721
Error = (ACT-FCST)	52	(130)	(75)	74	81	100	(9)	108	2	(64)
Percent Error = (Error/ACT)	9.8%	-25.1%	-15.2%	12.1%	11.8%	14.3%	-1.3%	12.8%	0.2%	-8.9%

FEVI Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	83	141	243	164	66	65	39	37	34	11
Actual	175	152	179	67	37	35	32	14	11	10
Error = (ACT-FCST)	92	11	(64)	(97)	(29)	(30)	(7)	(23)	(23)	(1)
Percent Error = (Error/ACT)	52.6%	7.2%	-35.8%	-144.8%	-78.4%	-85.7%	-21.4%	-163.9%	-207.4%	-14.3%

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1 ## 3.10 VANCOUVER ISLAND NET CUSTOMER ADDITIONS

FEVI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	2,537	3,188	2,857	3,888	4,043	3,590	3,443	3,564	2,933	2,178
Actual	3,611	4,901	6,359	4,380	4,629	5,137	3,097	2,139	2,236	1,563
Error = (ACT-FCST)	1074	1713	3502	492	586	1547	(346)	(1425)	(697)	(615)
Percent Error = (Error/ACT)	29.8%	35.0%	55.1%	11.2%	12.7%	30.1%	-11.2%	-66.6%	-31.2%	-39.4%

FEVI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	171	239	256	251	190	190	163	126	95	126
Actual	129	170	262	137	89	153	42	132	260	75
Error = (ACT-FCST)	(42)	(69)	6	(114)	(101)	(37)	(121)	6	165	(51)
Percent Error = (Error/ACT)	-32.6%	-40.6%	2.3%	-83.2%	-113.5%	-24.2%	-287.3%	4.3%	63.6%	-67.6%

FEVI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	13	32	19	11	(8)	(8)	17	19	20	32
Actual	(51)	(14)	(25)	121	73	11	14	133	-91	-32
Error = (ACT-FCST)	(64)	(46)	(44)	110	81	19	(3)	114	(111)	(64)
Percent Error = (Error/ACT)	125.5%	328.6%	176.0%	90.9%	111.0%	172.7%	-22.0%	85.4%	122.1%	200.7%

FEVI Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	-	-	34	6	(1)	(1)	1	1	1	0
Actual	34	(23)	27	(112)	(30)	(2)	(3)	(18)	-3	-1
Error = (ACT-FCST)	34	(23)	(7)	(118)	(29)	(1)	(4)	(19)	(4)	(1)
Percent Error = (Error/ACT)	100.0%	100.0%	-25.9%	105.4%	96.7%	50.0%	130.7%	105.4%	130.1%	142.7%

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1 ## 3.11 VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER

FEVI UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	45.1	51.3	56.3	54.7	51.2	49.6	50.9	52.0	50.9	46.9
Actual	52.6	51.5	51.6	49.7	52.3	52.7	49.7	47.8	47.2	46.2
Error = (ACT-FCST)	7.5	0.3	(4.7)	(5.0)	1.1	3.1	(1.2)	(4.2)	(3.7)	(0.7)
Percent Error = (Error/ACT)	14.3%	0.5%	-9.1%	-10.1%	2.1%	5.8%	-2.3%	-8.8%	-7.8%	-1.6%

FEVI UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	334.0	322.8	342.5	357.0	331.9	333.4	318.6	318.4	325.1	321.3
Actual	343.0	344.8	351.2	332.7	322.2	331.2	338.4	322.1	319.5	326.2
Error = (ACT-FCST)	9.0	22.0	8.7	(24.3)	(9.7)	(2.2)	19.8	3.7	(5.6)	5.0
Percent Error = (Error/ACT)	2.6%	6.4%	2.5%	-7.3%	-3.0%	-0.7%	5.9%	1.1%	-1.7%	1.5%

FEVI UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	4,030.8	3,068.6	4,171.0	4,411.0	3,628.7	3,882.2	3,197.0	3,397.6	3,541.9	3,521.1
Actual	4,060.0	4,180.7	4,074.2	3,826.5	3,403.8	3,603.9	3,708.0	3,457.5	3,551.6	3,626.5
Error = (ACT-FCST)	29	1112	(97)	(584)	(225)	(278)	511	60	9.7	105.4
Percent Error = (Error/ACT)	0.7%	26.6%	-2.4%	-15.3%	-6.6%	-7.7%	13.8%	1.7%	0.3%	2.9%

FEVI UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	5,996.2	5,635.7	5,343.6	5,281.6	4,799.8	4,169.3	4,338.1	5,221.1	5,695.2	5,938.9
Actual	5,052.0	5,157.5	5,260.4	4,368.5	4,726.7	6,022.6	5,751.4	5,858.6	6,302.6	5,914.5
Error = (ACT-FCST)	(944.2)	(478.2)	(83.3)	(913.1)	(73.1)	1853.3	1,413.4	637.6	607.4	(24.3)
Percent Error = (Error/ACT)	-18.7%	-9.3%	-1.6%	-20.9%	-1.5%	30.8%	24.6%	10.9%	9.6%	-0.4%

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1 ## 3.12 VANCOUVER ISLAND NORMALIZED DEMAND

FEVI Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	4.6	5.4	6.1	6.3	6.2	6.2	6.6	7.0	7.0	6.5
Actual	5.4	5.5	5.8	5.9	6.4	6.7	6.5	6.4	6.4	6.4
Error = (ACT-FCST)	0.8	0.1	(0.3)	(0.5)	0.1	0.5	(0.1)	(0.6)	(0.5)	(0.1)
Percent Error = (Error/ACT)	15.6%	1.5%	-5.6%	-8.3%	2.3%	6.9%	-1.4%	-10.1%	-8.3%	-1.7%
Abs. Percent Error	15.6%	1.5%	5.6%	8.3%	2.3%	6.9%	1.4%	10.1%	8.3%	1.7%

FEVI Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	3.0	3.1	3.4	3.6	3.4	3.4	3.3	3.3	3.4	3.5
Actual	3.2	3.3	3.4	3.3	3.2	3.4	3.5	3.3	3.4	3.5
Error = (ACT-FCST)	0.2	0.2	0.0	(0.3)	(0.1)	(0.1)	0.2	(0.0)	(0.0)	0.0
Percent Error = (Error/ACT)	6.3%	5.4%	1.4%	-8.0%	-3.4%	-1.8%	5.1%	0.0%	-0.3%	1.4%

FEVI Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	1.9	2.0	2.4	2.4	2.3	2.3	2.3	2.5	2.6	2.7
Actual	2.2	2.1	2.1	2.0	2.2	2.5	2.6	2.8	2.8	2.7
Error = (ACT-FCST)	0.3	0.1	(0.3)	(0.3)	(0.0)	0.2	0.3	0.3	0.2	(0.0)
Percent Error = (Error/ACT)	13.6%	6.5%	-14.6%	-16.8%	-1.9%	6.9%	13.2%	10.6%	6.5%	-0.8%

FEVI Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	0.5	0.8	1.2	0.8	0.3	0.3	0.2	0.2	0.2	0.1
Actual	0.8	0.9	0.8	0.6	0.3	0.2	0.2	0.2	0.1	0.1
Error = (ACT-FCST)	0.3	0.1	(0.4)	(0.2)	(0.0)	(0.05)	0.03	(0.03)	(0.11)	(0.00)
Percent Error = (Error/ACT)	37.5%	9.2%	-44.9%	-32.2%	-11.0%	(0.2459)	16.1%	-20.0%	-126.3%	-7.4%

FEVI Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commercial										
Forecast	5.4	5.9	7.0	6.8	5.9	6.0	5.7	6.0	6.2	6.2
Actual	6.2	6.3	6.3	6.0	5.8	6.1	6.3	6.2	6.3	6.2
Error = (ACT-FCST)	0.8	0.4	(0.6)	(0.8)	(0.2)	0.1	0.6	0.3	0.1	0.0
Percent Error = (Error/ACT)	12.9%	6.3%	-10.0%	-13.6%	-3.2%	1.0%	8.8%	4.2%	1.1%	0.4%
Abs. Percent Error	12.9%	6.3%	10.0%	13.6%	3.2%	1.0%	8.8%	4.2%	1.1%	0.4%

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3.13 *WHISTLER NET CUSTOMERS*

WH Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	2,536	2,681	2,775	2,889	3,034	3,122	3,041	3,145	3,115	3,218
Actual	2,608	2,709	2,828	2,936	2,977	3,045	3,070	3,119	3,169	3,182
Error = (ACT-FCST)	72	28	53	47	(57)	(77)	29	(26)	54	(36)
Percent Error = (Error/ACT)	2.8%	1.0%	1.9%	1.6%	-1.9%	-2.5%	0.9%	-0.8%	1.7%	-1.1%

WH Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	292	309	294	305	313	319	310	302	305	297
Actual	289	297	309	307	305	305	306	292	300	303
Error = (ACT-FCST)	(3)	(12)	15	2	(8)	(14)	(4)	(10)	(5)	6
Percent Error = (Error/ACT)	-1.0%	-4.0%	4.7%	0.7%	-2.6%	-4.6%	-1.4%	-3.5%	-1.8%	1.9%

WH Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	59	39	48	55	71	74	75	76	69	86
Actual	53	57	58	69	73	73	70	88	82	81
Error = (ACT-FCST)	(6)	18	10	14	2	(1)	(5)	12	13	(5)
Percent Error = (Error/ACT)	-11.3%	31.6%	16.9%	20.2%	2.7%	-1.4%	-7.1%	13.3%	16.2%	-6.1%

WH Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	5	10	22	18	4	4	1	1	1	1
Actual	14	14	11	4	1	1	1	1	1	1
Error = (ACT-FCST)	9	4	(11)	(14)	(3)	(3)	(0)	(0)	0	(0)
Percent Error = (Error/ACT)	64.3%	28.6%	-100.0%	-350.0%	-300.0%	-300.0%	-2.0%	-4.0%	1.9%	-4.8%

1 ## 3.14 *WHISTLER NET CUSTOMER ADDITIONS*

WH Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	61	84	81	81	98	88	31	47	24	49
Actual	100	101	119	108	41	68	25	49	50	13
Error = (ACT-FCST)	39	17	38	27	(57)	(20)	(6)	2	26	(36)
Percent Error = (Error/ACT)	39.0%	16.8%	31.8%	25.4%	-139.5%	-28.9%	-23.5%	3.1%	52.5%	-276.6%

WH Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	4	7	3	4	6	6	3	(1)	-0.3	-2.7
Actual	(6)	8	12	(2)	(2)	-	1	(14)	8	3
Error = (ACT-FCST)	(10)	1	9	(6)	(8)	(6)	(2)	(13)	8	6
Percent Error = (Error/ACT)	166.7%	11.9%	77.4%	300.0%	400.0%		-167.0%	90.5%	104.2%	188.9%

WH Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	-	(5)	(2)	(1)	2	1	1	2	-0.7	4.0
Actual	5	4	1	11	4	-	(3)	18	-6	-1
Error = (ACT-FCST)	5	9	3	12	2	(1)	(4)	16	(5)	(5)
Percent Error = (Error/ACT)	100.0%	225.0%	339.0%	109.1%	50.0%		133.0%	90.9%	89.0%	495.2%

WH Customer Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	-	-	4	2	-	-	0	0	(1)	0
Actual	4	-	(3)	(7)	(3)	-	-	-	-	-
Error = (ACT-FCST)	4	0	(7)	(9)	(3)	0	(0)	(0)	1	(0)
Percent Error = (Error/ACT)	100.0%		233.3%	128.6%	100.0%					

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1 ## 3.15 WHISTLER NORMALIZED USE PER CUSTOMER

WH UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	85.1	97.9	102.1	99.5	99.0	95.8	101.8	102.1	104.4	102.0
Actual	97.7	93.5	96.3	94.2	101.5	100.3	103.6	100.6	99.7	96.7
Error = (ACT-FCST)	13	(4)	(6)	(5)	2	4	2	(2)	(5)	(5)
Percent Error = (Error/ACT)	12.9%	-4.7%	-6.1%	-5.6%	2.4%	4.5%	1.8%	-1.5%	-4.7%	-5.5%

WH UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	465.0	792.9	592.7	515.5	419.5	384.7	356.2	363.4	449.2	441.5
Actual	520.2	479.4	511.8	465.8	417.5	438.7	499.8	467.4	449.1	440.4
Error = (ACT-FCST)	55	(314)	(81)	(50)	(2)	54	144	104	(0)	(1)
Percent Error = (Error/ACT)	10.6%	-65.4%	-15.8%	-10.7%	-0.5%	12.3%	28.7%	22.2%	0.0%	-0.3%

WH UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	4,326.0	6,706.9	6,824.3	5,886.5	4,737.2	5,475.7	4,179.4	4,077.7	4,161	4,308
Actual	5,638.0	5,107.9	5,747.4	5,392.0	4,220.8	4,558.7	4,869.8	4,608.8	4,428	4,409
Error = (ACT-FCST)	1,312	(1,599)	(1,077)	(495)	(516)	(917)	690	531	267	101
Percent Error = (Error/ACT)	23.3%	-31.3%	-18.7%	-9.2%	-12.2%	-20.1%	14.2%	11.5%	6.0%	2.3%

WH UPC, GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	5,888.0	4,328.3	4,702.9	4,654.3	5,121.0	5,396.2	5,934.6	12,413.7	13,465.3	12,661.8
Actual	5,078.0	4,557.0	4,860.0	5,045.3	5,929.5	12,508.9	12,901.9	12,020.7	13,660.9	11,068.2
Error = (ACT-FCST)	(810)	229	157	391	808	7,113	6,967	(393)	195.6	(1,593.6)
Percent Error = (Error/ACT)	-16.0%	5.0%	3.2%	7.7%	13.6%	56.9%	54.0%	-3.3%	1.4%	-14.4%

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3.16 *WHISTLER NORMALIZED DEMAND*

WH Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 1										
Forecast	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Actual	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
Percent Error = (Error/ACT)	14.6%	-4.1%	-5.3%	-4.6%	1.8%	2.4%	2.8%	-2.4%	-3.2%	-5.9%
Abs. Percent Error	14.6%	4.1%	5.3%	4.6%	1.8%	2.4%	2.8%	2.4%	3.2%	5.9%

WH Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 2										
Forecast	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Actual	0.2	0.1	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.1
Error = (ACT-FCST)	0.0	(0.1)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	(0.0)	0.0
Percent Error = (Error/ACT)	10.0%	-75.0%	-12.1%	-9.6%	-1.6%	8.3%	27.9%	20.1%	-3.0%	1.2%

WH Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 3										
Forecast	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.4
Actual	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Error = (ACT-FCST)	0.0	0.0	(0.0)	0.0	(0.0)	(0.1)	0.0	0.1	0.1	(0.0)
Percent Error = (Error/ACT)	13.3%	3.5%	-3.8%	5.5%	-11.5%	-18.4%	11.2%	18.9%	23.3%	-0.2%

WH Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Schedule 23										
Forecast	0.03	0.04	0.09	0.08	0.02	0.02	0.01	0.01	0.01	0.01
Actual	0.06	0.06	0.06	0.05	0.02	0.01	0.01	0.01	0.01	0.01
Error = (ACT-FCST)	0.03	0.02	-0.03	-0.03	0.00	-0.01	0.01	0.00	0.00	0.00
Percent Error = (Error/ACT)	50.9%	32.2%	-44.7%	-73.7%	-7.7%	-72.6%	53.4%	-6.5%	2.9%	-16.7%

WH Demand, PJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commercial										
Forecast	0.4	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.5
Actual	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.5
Error = (ACT-FCST)	0.1	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	0.1	0.1	0.1	(0.0)
Percent Error = (Error/ACT)	16.8%	-15.0%	-11.1%	-5.4%	-8.5%	-12.4%	17.2%	18.7%	16.0%	-0.2%
Abs. Percent Error	16.8%	15.0%	11.1%	5.4%	8.5%	12.4%	17.2%	18.7%	16.0%	0.2%

3.17 *FORT NELSON NET CUSTOMER*

FTN Customers Rate Schedule 1 - Residential	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	1,997	1,965	1,966	1,941	1,918	1,864	1,853	1,830	1,793	1,846
Actual	1,945	1,927	1,919	1,898	1,880	1,860	1,836	1,830	1,838	1,880
Error = (ACT-FCST)	(52)	(38)	(47)	(43)	(38)	(4)	(17)	0	45	34
Percent Error = (Error/ACT)	-2.7%	-2.0%	-2.4%	-2.3%	-2.0%	-0.2%	-0.9%	0.0%	2.5%	1.8%

FTN Customers Rate Schedule 2 - Small Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.1	479	478	480							
Forecast Rate Schedule 2				465	468	450	445	430	435	452
Actual Rate Schedule 2.1	478	476	473							
Actual Rate Schedule 2				460	452	445	445	446	451	446
Error = (ACT-FCST)	(1)	(2)	(7)	(5)	(16)	(5)	(0)	16	16	(6)
Percent Error = (Error/ACT)	-0.2%	-0.4%	-1.5%	-1.1%	-3.5%	-1.1%	-0.1%	3.6%	3.5%	-1.4%

FTN Customers Rate Schedule 3- LargeCommercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.2	34	7	7							
Forecast Rate Schedule 3				19	19	17	13	20	17	15
Actual Rate Schedule 2.2	7	6	4							
Saved to S: Drive e Schedule 3				14	17	17	16	22	15	14
Error = (ACT-FCST)	(27)	(1)	(3)	(5)	(2)	-	3	2	(2)	(1)
Percent Error = (Error/ACT)	-385.7%	-16.7%	-75.0%	-35.7%	-11.8%	0.0%	16.7%	9.1%	-15.6%	-7.1%

3.18 *FORT NELSON NET CUSTOMER ADDITIONS*

FTN Customer Additions Rate Schedule 1 - Residential	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	13	1	1	32	(23)	(16)	(13)	(14)	(23)	8
Actual	(18)	(18)	(8)	(21)	(18)	(20)	(24)	(6)	8	42
Error = (ACT-FCST)	(31)	(19)	(9)	(53)	5	(4)	(11)	8	31	34
Percent Error = (Error/ACT)	172.2%	105.6%	112.5%	252.4%	-27.8%	20.0%	45.8%	-139.3%	385.0%	81.4%

FTN Customer Additions Rate Schedule 2.1/2 - Small Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.1	11	2	2							
Forecast Rate Schedule 2				9	3	(1)	(3)	(8)	(5)	1
Actual Rate Schedule 2.1	4	(2)	(3)							
Actual Rate Schedule 2				3	(8)	(7)	-	1	5	(5)
Error = (ACT-FCST)	(7)	(4)	(5)	(6)	(11)	(6)	3	9	10	(6)
Percent Error = (Error/ACT)	-175.0%	200.0%	166.7%	-200.0%	137.5%	85.7%		850.0%	200.0%	126.7%

FTN Customer Additions Rate Schedule 2.2/3 - Large Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.2	1	-	-							0
Forecast Rate Schedule 3				(1)	-		(1)	2	1	-1
Actual Rate Schedule 2.2	-	(1)	(2)							
Actual Rate Schedule 3				(6)	3	-	(1)	6	(7)	(1)
Error = (ACT-FCST)	(1)	(1)	(2)	(5)	3	-	-	5	(8)	-
Percent Error = (Error/ACT)		100.0%	100.0%	83.3%	100.0%		0.0%	75.0%	109.5%	0.0%

3.19 *FORT NELSON USE PER CUSTOMER*

FTN UPC Rate Schedule 1 - Residential	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	135	133	132	125	123	126	125.8	125.6	129.9	119.1
Actual	134	130	128	128	129	129	129.3	126.2	124.2	121.0
Error = (ACT-FCST)	(1)	(3)	(5)	3	6	3	4	1	(6)	2
Percent Error = (Error/ACT)	-0.4%	-2.6%	-3.7%	2.2%	4.6%	2.2%	2.7%	0.5%	-4.6%	1.6%

FTN UPC Rate Schedule 2.1/2 - Small Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.1	443	444	425							
Forecast Rate Schedule 2				349	323	370	337	356	368	347
Actual Rate Schedule 2.1	466	448	435							
Actual Rate Schedule 2				402	383	382	390	385	368	362
Error = (ACT-FCST)	23	4	9	53	60	12	53	29	(0)	15
Percent Error = (Error/ACT)	4.9%	0.8%	2.2%	13.2%	15.7%	3.1%	13.5%	7.5%	0.0%	4.2%

FTN UPC Rate Schedule 2.2/3 - Large Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.2	3,584	8,081	8,103							
Forecast Rate Schedule 3				3,164	2,802	5,307	6,378	5,605	6,038	4,559
Actual Rate Schedule 2.2	7,869	8,086	9,169							
Actual Rate Schedule 3				4,910	4,643	5,328	7,049	5,195	4,358	4,832
Error = (ACT-FCST)	4,285	4	1,066	1,746	1,842	21	671	(410)	(1,681)	273
Percent Error = (Error/ACT)	54.5%	0.1%	11.6%	35.6%	39.7%	0.4%	9.5%	-7.9%	-38.6%	5.7%

3.20 *FORT NELSON NORMALIZED DEMAND*

FTN Demand GJ Rate Schedule 1 - Residential	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	267,546	261,825	259,874	244,160	236,900	235,314	233,889	230,713	234,300	218,716
Actual	262,275	251,350	245,434	244,434	243,175	239,912	238,860	231,474	228,839	223,525
Error = (ACT-FCST)	(5,271)	(10,475)	(14,440)	274	6,275	4,598	4,971	761	(5,461)	4,809
Percent Error = (Error/ACT)	-2.0%	-4.2%	-5.9%	0.1%	2.6%	1.9%	2.1%	0.3%	-2.4%	2.2%

FTN FTN Demand GJ Rate Schedule 2.1/2- Small Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.1	208,642	211,897	203,742							
Forecast Rate Schedule 2				160,160	150,377	166,828	150,115	154,312	161,126	155,531
Actual Rate Schedule 2.1	221,733	214,211	205,955							
Actual Rate Schedule 2				185,202	173,841	171,131	173,378	170,787	164,944	161,223
Error = (ACT-FCST)	13,091	2,314	2,213	25,042	23,464	4,302	23,263	16,475	3,818	5,693
Percent Error = (Error/ACT)	5.9%	1.1%	1.1%	13.5%	13.5%	2.5%	13.4%	9.6%	2.3%	3.5%

FTN FTN Demand GJ Rate Schedule 2.2/3 - Large Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast Rate Schedule 2.2	120,843	56,570	56,722							
Forecast Rate Schedule 3				61,061	53,232	90,216	87,068	107,587	102,472	68,382
Actual Rate Schedule 2.2	55,081	48,357	41,919							
Actual Rate Schedule 3				70,419	71,320	90,569	115,562	101,553	82,789	70,768
Error = (ACT-FCST)	(65,762)	(8,213)	(14,804)	9,358	18,088	353	28,494	(6,034)	(19,682)	2,387
Percent Error = (Error/ACT)	-119.4%	-17.0%	-35.3%	13.3%	25.4%	0.4%	24.7%	-5.9%	-23.8%	3.4%

FTN Demand GJ Commercial	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	329,485	268,467	260,464							
Forecast				221,221	203,609	257,044	237,183	261,900	263,598	223,912
Actual	276,814	262,568	247,874							
Actual				255,621	245,161	261,699	288,940	272,340	247,734	231,992
Error = (ACT-FCST)	(52,672)	(5,899)	(12,591)	34,400	41,552	4,655	51,757	10,441	(15,864)	8,080
Percent Error = (Error/ACT)	-19.0%	-2.2%	-5.1%	13.5%	16.9%	1.8%	17.9%	3.8%	-6.4%	3.5%

FTN Demand GJ Rate Schedule 25* - General Firm Transportation	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	55,832	39,685	39,684	41,500	41,500					
Actual	41,110	41,847	43,197	37,105	29,541					
Error = (ACT-FCST)	(14,722)	2,162	3,513	(4,395)	(11,959)					
Percent Error = (Error/ACT)	-35.8%	5.2%	8.1%	-11.8%	-40.5%					

Note: Single remaining customer switched to RS 3 in 2020

FTN Total Demand GJ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast	652,863	569,978	560,023	506,881	482,009	492,358	471,072	492,613	497,898	442,628
Actual	580,199	555,765	536,505	537,160	517,877	501,611	527,801	503,815	476,573	455,516
Error = (ACT-FCST)	(72,664)	(14,212)	(23,517)	30,279	35,868	9,253	56,729	11,202	(21,325)	12,889
Percent Error = (Error/ACT)	-12.5%	-2.6%	-4.4%	5.6%	6.9%	1.8%	10.7%	2.2%	-4.5%	2.8%

Appendix B

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-278-22 – FEI APPLICATION FOR COMMON RATES AND 2022 REVENUE REQUIREMENTS FOR THE FORT NELSON SERVICE AREA						
1.	32	3	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	The Panel approves FEI to establish, for BCUC review, the actual Fort Nelson Residential Customer Common Rate Phase-in Rider each year in FEI's regulatory review process to set delivery rates, commencing in 2023, based on an updated forecast of FEFN's residential customer demand and the remaining balance of the deferral account each year for the five-year phase-in period.	Phase-in has concluded in 2027.	Section 10.3.2
G-69-25 AND DECISION – FEI RATE SETTING FRAMEWORK FOR 2025 TO 2027						
2.	21 and 29		O&M Costs impacts by the AMI project	To properly track and report on the annual costs and savings, FEI proposes to forecast O&M costs impacted by the AMI project in each Annual Review and provide a discussion of its expectations for the costs for the coming year, with variances between forecast and actual costs recorded in the flow-through deferral account and returned to or recovered from customers in subsequent years. …FEI is approved to do the following: …Remove $19.783 million of O&M costs from its 2024 Base O&M that will be impacted by its AMI project and reclassify the related costs to Forecast (flow-through) O&M.	Ongoing during the Rate Framework term.	Section 6.3.4
3.	49		Hydrogen Integration	The Panel directs FEI to address hydrogen integration in its next rates application after the conclusion of the Rate Framework.	Will be addressed in FEI's 2028+ Rates Application.	n/a
4.	65-66		SQIs – FEI's Energy Transition Informational Indicators	***Renewable and Low Carbon Energy Supply Volume Indicator:*** The Panel directs FEI to also include specific reporting on the mix of renewable and low-carbon gas sources, as well as the percentage of these sources in its total gas supply, in each Annual Review. ***Scope 3 Emissions:*** The Panel directs FEI to include an informational indicator for Scope 3 emissions as part of its energy transition informational indicators.	Ongoing during the Rate Framework term.	Section 13.2.4

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	78		Next Rates Application	In its next rates application for the period beginning January 1, 2028, the Panel provides the following directions to FortisBC: • For FEI and FBC, evaluate the merits of a price cap model that takes a top-down approach to rate-setting, such that the customers' rate is the starting point as opposed to the end product; • For FEI, evaluate alternate rate frameworks based on a jurisdictional review of other research that begin with an optimal gas delivery price as the starting point; • Evaluate whether such a new common rates plan could reasonably be implemented for both FEI and FBC given potentially different impacts of the energy transition on their operations, or whether the next rates plan would merit separate rate frameworks for each of the two utilities; and • For FEI and FBC, evaluate targeted incentives that may be appropriate to introduce to further incent FEI's and FBC's energy transition work.	Will be addressed in FEI's 2028+ Rates Application.	n/a
6.	82		Clean Growth Innovation Fund (CGIF)	The Panel directs FEI in its next rates application to (i) provide a comprehensive report of the utility of the CGIF in regard to its stated objectives; (ii) evaluate the need for continuation of the CGIF; and (iii) evaluate alternate mechanisms that might address these objectives including a review of any relevant mechanics in other Canadian jurisdictions.	Will be addressed in FEI's 2028+ Rates Application.	n/a
G-162-25 - FEI DISCONTINUE OPERATION OF THE LNG FUELING STATION AT VEDDER TRANSPORT LTD.						
7.		3	Recovery of Amounts	FEI is directed to provide an update regarding the recovery of amounts associated with the decommissioning of the Vedder Abbotsford Fueling Station in its next Annual Review of Delivery Rates application to the BCUC.		Section 5.2.4.3

Appendix C

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Annual Review for 2027 Delivery Rates

BEFORE:
[X. X. Last Name, Panel Chair]
[X. X. Last Name, Commissioner]
[X. X. Last Name, Commissioner]

on [Month Day, Year]

ORDER

WHEREAS:

A. On March 18, 2025, the British Columbia Utilities Commission (BCUC) issued Order G-69-25 for FortisBC Energy Inc. (FEI) and Order G-70-25 for FortisBC Inc. (FBC) approving a Rate Setting Framework (Rate Framework) for 2025 through 2027 (Rate Framework Decision). In accordance with the Rate Framework Decision, FEI is to conduct an annual review process to set delivery rates for each year (Annual Review);

B. By letter dated June 10, 2026, FEI proposed a regulatory timetable for the Annual Review of its 2027 delivery rates (2027 Annual Review);

C. By Order G-150-26 dated July 14, 2026, the BCUC established the regulatory timetable for the 2027 Annual Review, which included FEI filing its Annual Review materials, intervener registration, one round of information requests, letters of comment, and written final and reply arguments;

D. On July 24, 2026, FEI submitted its materials for the 2027 Annual Review (Application). In the Application, FEI requests approval of a 3.43 percent permanent delivery rate increase over the 2026 delivery rates, effective January 1, 2027, among other things, pursuant to sections 59 to 61 of the *Utilities Commission Act*; and

E. The BCUC has reviewed the Application, evidence, and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act* and for the reasons outlined in the decision accompanying this order, the BCUC orders as follows:

1. FEI is approved to recover the 2027 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2027.

2. FEI is approved to set the 2027 Revenue Stabilization Adjustment Mechanism (RSAM) rate rider at $0.406 per GJ on a permanent basis, effective January 1, 2027.

3. FEI is approved to record the actual after-tax costs of the 2026 equity issuance in the Flotation Costs deferral account.

4. FEI is approved to establish the following rate base deferral accounts:

    a. The 2028+ Rate Setting Application deferral account, with the amortization period to be determined in a future proceeding;

    b. The 2026 Long-Term Gas Resource Plan (LTGRP) deferral account. FEI is approved to amortize the balance in the deferral account over a three-year period starting January 1, 2027; and

    c. The 2026 Mains Extensions (MX) Policies Review deferral account. FEI is approved to amortize the balance in the deferral account over a one-year period starting January 1, 2027.

5. FEI is directed to file as a compliance filing, amended tariff pages for the BCUC's endorsement and tariff continuity and bill impact schedules, reflecting the approved 2027 permanent delivery rates by December 15, 2026.

DATED at the City of Vancouver, in the Province of British Columbia, this [XXth] day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner