Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604)908-2790
Fax: (604) 576-7074
www.fortisbc.com

August 12, 2020

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

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-165-20 (MRP Plan)

Annual Review for 2020 and 2021 Delivery Rates

In accordance with the MRP Plan and BCUC Order G-209-20 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2020 and 2021 Delivery Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to the FortisBC Application for Multi-Year Rate Plan for 2020 through 2024

FORTISBC

FORTISBC ENERGY INC.

Multi-Year Rate Plan

for 2020 through 2024

Annual Review for 2020 and 2021 Delivery Rates

Volume 1 - Application

August 12, 2020

Table of Contents

List of Appendices

Index of Tables and Figures

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) Order G-165-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FEI for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

By Order G-302-19, the BCUC approved FEI's 2020 rates on an interim basis, pending a decision on the MRP. With the filing of this Application, FEI seeks to commence the annual review process to set permanent rates for 2020 and 2021.

The MRP approved by the Decision attached to Order G-165-20 (MRP Decision) provides stable levels of O&M funding, the flexibility to innovate and adapt, and incentive to invest in the future, while maintaining service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

In the first year of the MRP, FEI anticipates relatively minor O&M savings in 2020 as compared to that allowed under the O&M formula, and as a result has not forecast any savings or related earnings sharing. The reason for FEI's expectation of relatively minor formulaic O&M savings is threefold. First, as described in its MRP application, FEI expects to face both continued and new cost pressures. Second, FEI faces additional pressures on its spending resulting from the denial of $2.36 million of incremental O&M expenses for Customer Expectations and Engagement activities, as directed by the BCUC in the MRP Decision. Third, with the inclusion of a 0.5 percent Productivity Improvement Factor (PIF), which was directed by the BCUC as part of the MRP Decision, FEI will be challenged to achieve savings beyond the embedded PIF.

FEI will continue to pursue productivity improvements as it seeks to manage its business needs within the challenges described above. While such potential productivity improvements may lead to cost reductions, FEI's focus will be on efficient allocation of resources within the business and "doing more with what we have". FEI believes this approach to productivity represents an appropriate balancing of the ongoing need to manage costs and mitigate customer rate pressure, while providing resources to support growth and the challenges being faced, and maintaining service levels.

1.1.1 Permanent 2020 Rates

The proposed permanent rates for 2020 flowing from the approved formulas and forecasts set out in the Application result in a 3.27 percent delivery rate increase from 2019 rates. This increase, which is further described in Section 1.4, incorporates the actual 2019 results of the final year of the 2014-2019 Performance Based Ratemaking (PBR) Plan. Overall, FEI proposes to distribute $1.653 million (before tax) in earnings sharing to customers in 2020. This amount is a true-up from FEI's 2019 projected earnings sharing and does not reflect savings in 2020 that may be achieved.

Due to the expected timing of a decision on this Application, FEI is proposing to set permanent 2020 rates at the existing interim levels and to capture the revenue deficiency greater than the 2 percent approved as interim in the existing 2017 & 2018 Revenue Surplus deferral account as an offset to prior years' revenue surpluses.

1.1.2 Permanent 2021 Rates

The proposed rate change for 2021 after drawing down the 2017 & 2018 Revenue Surplus deferral account to zero is a 6.59 percent delivery rate increase from 2020 rates, or an increase of approximately $27 or 3.1 percent to the annual bill for an average residential customer[1]. After consideration of the delivery rate riders, the annual bill impact is an increase of approximately $29 or 3.4 percent for a residential customer. The increase is primarily due to FEI's 2021 depreciation and amortization expense increases of $48.281 million when compared to 2020 Projected, as noted in Section 1.4.4 below.

As noted above, FEI anticipates relatively minor formulaic O&M savings in 2020. FEI continues to maintain a high level of service quality as indicated by meeting the Service Quality Indicators (SQIs) approved in the MRP Decision. Once 2020 results are known, FEI will determine the 2020 earnings sharing, if any, when setting rates for 2022.

In the subsections below, FEI sets out the approvals it is seeking 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 rate changes for 2020 and 2021 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

1.2 APPROVALS SOUGHT

With this Application, FEI requests BCUC approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act*:

1. Existing 2020 interim rates be made permanent, effective January 1, 2020;
2. A permanent delivery rate increase of 6.59 percent, effective January 1, 2021;
3. The following deferral account approvals as described in Sections 7.5 and 12.4:
    - Creation of rate base deferral accounts for the following regulatory proceedings:
        - Annual Reviews for 2020 to 2024 Rates, with balances to be amortized in the following year;

[1] Based on a using approximately 90 GJs per year.

- 2022 Long-Term Gas Resource Plan, with the amortization period to be determined in a future proceeding;
- BCUC Initiated Inquiries, with balances amortized in the following year; and
- The City of Coquitlam Application Proceeding, with amortization over 3 years beginning January 1, 2021.

- The previously-approved 2020 Revenue Requirement Application deferral account to be renamed to the 2020–2024 MRP Application deferral account, and amortized over a five year period beginning January 1, 2020; and
- Draw down of the 2017 & 2018 Revenue Surplus deferral account in the amount of $10.338[2] million in 2020 and $35.287[3] million in 2021, bringing the account balance to zero.

4. A Biomethane Variance Account (BVA) Rate Rider for 2021 in the amount of $0.022 per gigajoule (GJ) as calculated in Section 10.2.1;
5. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2021 in the amounts set out in Table 10-5 in Section 10.2.2;
6. Continuation of the debiting of the Midstream Cost Reconciliation Account (MCRA) and crediting of Other Revenue in the amount of $300 thousand per month for the period of January 1, 2020 to October 31, 2020. Effective November 1, 2020, and for the duration of the MRP term, debiting of the MCRA and crediting of Other Revenue in the amount of $346.617 per MMcfd (equivalent to approximately $0.3059/GJ per day), as described in Section 5.3.2;
7. The 2021 Core Market Administration Expense (CMAE) budget of $5.524 million, as set out in Appendix B, and the allocation of the CMAE between FEI's Commodity Cost Reconciliation Account (CCRA) and MCRA based on the existing allocation percentages of 30 percent and 70 percent, respectively; and
8. To record COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account as discussed in Section 12.2.1 of the Application.

A draft order is included in Appendix D.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FEI's response or where it is addressed in the Application.

[2] Before Tax.
[3] Ibid.

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	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.	FEI has not identified any efficiency initiatives with a payback beyond the end of the MRP period
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 10.2.3
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 Rate Changes for 2020 and 2021

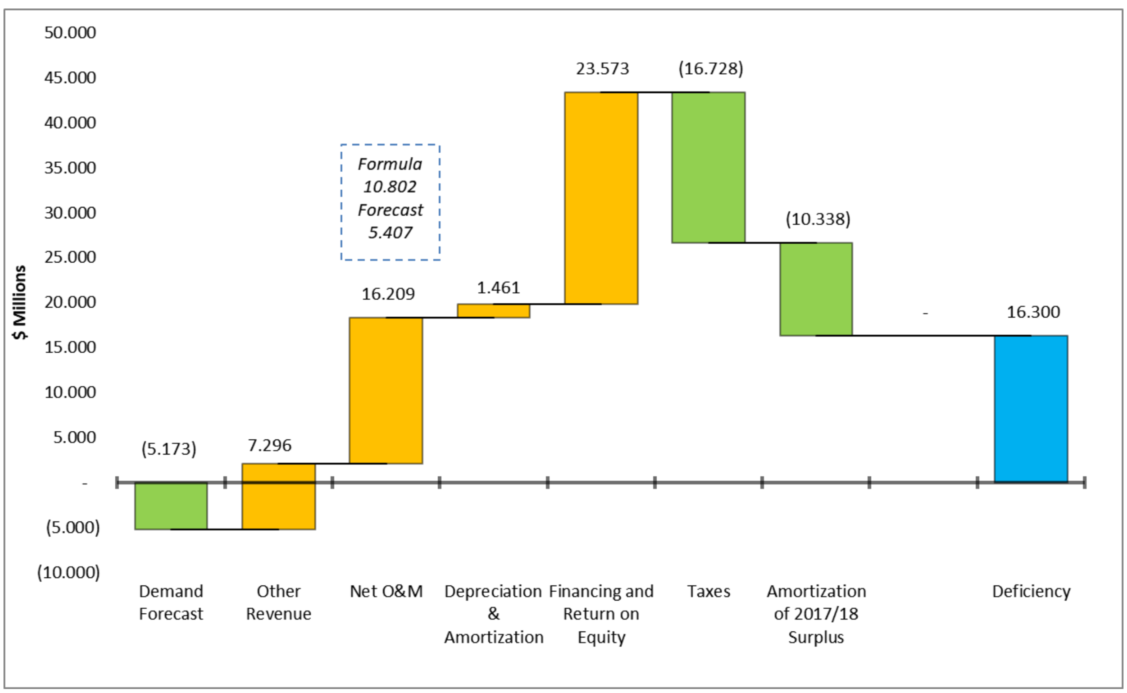
FEI has calculated the 2020 revenue requirement using a combination of the approved formulas for O&M and Growth Capital and the approved forecasts for Sustainment/Other Capital from the MRP Decision as well as projected 2020 amounts for items which are forecast annually. The projected 2020 amounts for these forecast items include six months of actual results up to June 30, 2020.

The delivery rates for 2020 flowing from the revenue requirement components set out in the Application result in a 3.27 percent increase from 2019 delivery rates; however, FEI is proposing to make permanent the existing interim delivery rates for 2020, effective January 1, 2020, and to capture the revenue deficiency greater than 2 percent in the existing 2017 & 2018 Revenue Surplus deferral account.

The proposed delivery rates for 2021, after drawing down the balance of the 2017 & 2018 Revenue Surplus deferral account, result in a 6.59 percent increase from 2020 delivery rates.

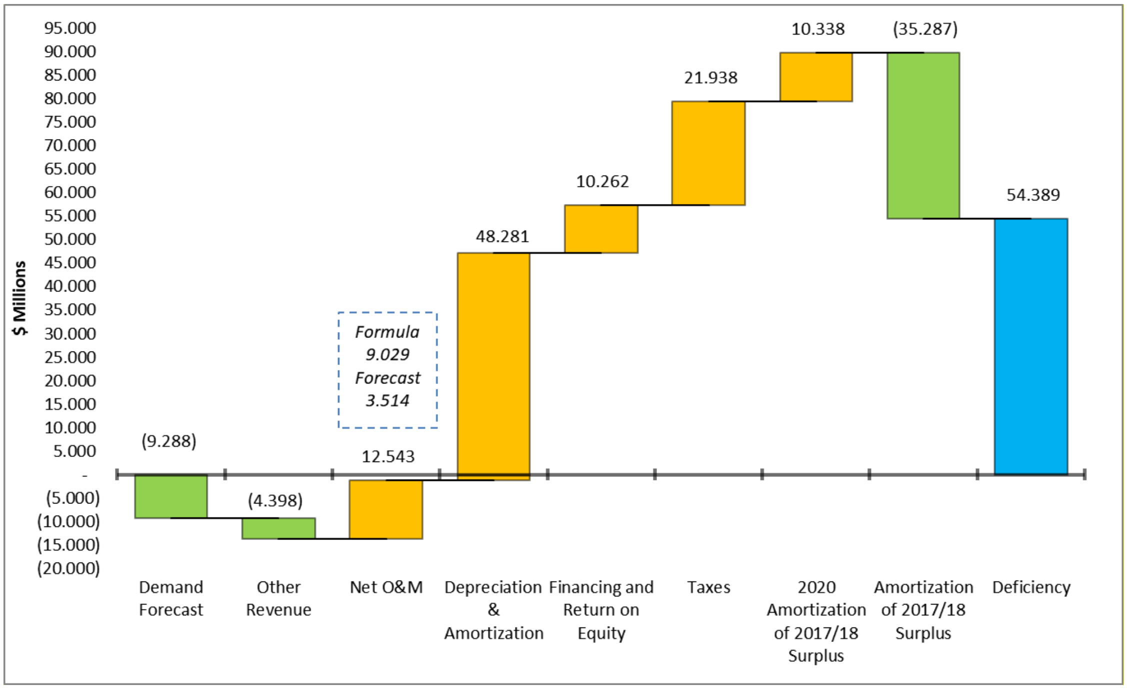
The following charts summarize the items that contribute to the 2020 and 2021 revenue deficiencies, including the proposed draw down of $10.338[4] million in 2020 and $35.287[5] million in 2021 from the 2017 & 2018 Revenue Surplus deferral account. The charts show each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2020 and 2021 deficiencies of $16.300 million and $54.389 million, respectively, are then the sum of all of the previous bars and are shown at the end of the charts in blue. For 2020, the blue bar represents the sum required to bring the total revenue deficiency to the deficiency determined when setting interim rates for 2020 (2 percent). For 2021, the blue bar represents the sum required to bring the total revenue deficiency to $54.389 million (6.59 percent).

Figure 1-1: 2020 Delivery Revenue Deficiency ($ millions)



4 Before Tax.
5 Ibid.

Figure 1-2: 2021 Delivery Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.4.1 Demand Forecast (Section 3)

In 2020, demand is projected to be nearly equal to 2019 Approved at 235 PJs. The 2020 Projection has Residential demand increasing by 0.3 PJ, Commercial demand decreasing by 2.3 PJs and Industrial demand increasing by 1.3 PJs. Overall, the changes in 2020 demand reduce the 2020 deficiency by $5.173 million when compared to 2019 Approved. In 2021, demand is forecast to decrease by approximately 2 PJs compared to 2020 Projected demand. The 2 PJ decrease is predominantly made up of a 1.8 PJ decrease in Residential demand. While demand has decreased slightly overall, FEI is forecasting an increase in LNG demand (Rate Schedule 46) which attracts a higher delivery rate than other rate schedules; consequently, the net impact is that the 2021 deficiency is reduced by $9.288 million. FEI's 2020 Projected revenue at 2019 existing rates and 2021 Forecast revenue at 2020 approved interim rates is $1,299.148 million and $1,390.853 million, respectively. FEI's 2020 Projected and 2021 Forecast gross delivery margin is $849.330 million and $874.918 million, respectively.

1.4.2 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2020 deficiency when compared to 2019 Approved by approximately $7.296 million, mainly due to a decrease in SCP Third Party Revenue. Other Revenue is forecast to reduce the 2021 deficiency by approximately $4.398 million, mainly due to more costs being transferred to the MCRA than in prior years.

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

FEI establishes the majority of its O&M costs by formula during the MRP term. For 2020, the formula incorporates an inflation factor (I-Factor) of 2.290 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers,[6] for a total increase in formula O&M of 5.2 percent from 2019 Approved. O&M forecast outside of the formula is increasing by 63.3 percent over 2019 Approved, primarily due to Pension and OPEB and Insurance expense increases, and the addition of BCUC Fees and Integrity Digs as forecast O&M items. The 2020 increase in total O&M expense net of capitalized overhead is $16.209 million.

For 2021, the O&M formula incorporates an inflation factor (I-Factor) of 3.358 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent and uses a forecast of the change in average customers[7] for a total increase in formula O&M of 4.1 percent from 2020 formula O&M. O&M forecast outside of the formula is increasing by 8.0 percent over 2020 Projected, primarily due to Pension and OPEB and Insurance expense increases. The 2021 increase in total O&M expense net of capitalized overhead is $12.543 million.

1.4.4 Depreciation and Amortization (Section 7 and Section 12)

FEI's depreciation expense decreased by $9.893 million in 2020. Depreciation decreased by $11.904 million from adopting new depreciation rates approved in the depreciation study filed with the MRP Application, with an offsetting $2.011 million increase in expense from net plant additions. FEI's amortization expense increased by $11.354 million in 2020. FEI's Net Salvage Provision, which is included in amortization expense, increased by $12.617 million from applying the net salvage rates approved in the depreciation study filed with the MRP application.

FEI's 2021 depreciation and amortization expense increased by $48.281 million compared to 2020 Projected. Depreciation expense increased by $9.980 million as a result of CPCN additions to plant for the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) project, Tilbury Expansion project and Inland Gas Upgrade project, as discussed in Section 7. Amortization in 2021 increased by $38.301 million primarily from the elimination the credit flow-through variance embedded in 2020 rates from the final year of the 2014 – 2019 PBR Plan.

1.4.5 Financing and Return on Equity (Section 8)

The impact to FEI's 2020 and 2021 deficiency is a sum of financing rate changes, the ratio of long-term debt vs. short-term debt, and changes in rate base.

For 2020, FEI has issued $200 million of long-term debt mid-year, and is forecasting a short-term debt rate of 1.65 percent, a decrease from the 3.10 percent short-term debt rate embedded in the 2019 Approved revenue requirement. Overall, FEI's deficiency is reduced by $11.004 million from financing rate changes and further reduced by $0.973 million from the ratio change

[6] Modified by 75 percent.
[7] Ibid.

between long-term and short-term debt. Resetting rate base after exiting the 2014-2019 PBR Plan has increased FEI's 2020 deficiency by $7.614 million, as discussed in Section 14.2. A further increase in 2020 rate base has contributed $27.936 million to FEI's deficiency when compared to 2019 Approved, due to a combination of the LMIPSU project entering rate base in 2020 and regular capital additions, as discussed in Section 7.

For 2021, FEI has forecast a mid-year long-term debt issue of $200 million and is forecasting a short-term debt rate of 2.19 percent, an increase from the 1.65 percent short-term debt rate embedded in the 2020 Projected revenue requirement. Overall, FEI's deficiency is reduced by $3.344 million from financing rate changes and increased by $3.157 million from the ratio change between long-term and short-term debt. The increase in 2021 rate base has contributed $10.449 million to FEI's deficiency when compared to 2020 Projected due to a combination of CPCN additions and regular capital additions entering rate base, as discussed in Section 7.

FEI has utilized the approved 2020 and 2021 capital structure and return on equity of 38.5 percent at 8.75 percent, respectively.

1.4.6 Taxes (Section 9)

FEI's 2020 property taxes are projected to increase by 0.6 percent or $0.400 million from 2019 Approved, and 2021 property taxes are forecast to increase by 5.7 percent or $3.852 million from 2020 Projected. These increases are driven by construction activities, market value increases and changes in tax policies of local taxing authorities.

There has been no change in the income tax rate of 27 percent from 2019. Taxes are forecast to decrease in 2020 by $17.128 million, primarily due to a decrease to adjustments to taxable income from the Federal government's Accelerated Investment Incentive regime, and increase in 2021 by $18.086 million due to an increase in delivery margin required mainly to offset an increase in amortization of deferred charges.

1.4.7 Service Quality Indicators[8] (Section 13)

FEI's June 2020 year-to-date SQI results indicate that the Company's overall performance to date meets service quality requirements. In June 2020, for those SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one, Meter Reading Accuracy, lower than the benchmark and threshold due to the impact of COVID-19. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years. Details of the SQIs are included in Section 13.

[8] FEI's Final 2018 and 2019 SQIs, pertaining to the PBR Plan, are provided in Section 14.

2. FORMULA DRIVERS

2.1 *INTRODUCTION AND OVERVIEW*

This section provides the calculation of the Inflation Factor (or I-Factor) used for calculating the 2020 and 2021 O&M and Growth Capital amounts according to the MRP formula.

In the MRP Decision and Order G-165-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals[9].

The MRP Decision approved the elimination of the lagging growth factor and approved the use of a forecast of growth[10] to determine Formula O&M and Formula Growth Capital. Further, the MRP Decision approved the elimination of a growth factor multiplier for Formula Growth Capital and determined that a growth factor multiplier of 75 percent for Formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2020 and 2021, FEI has used July 2017 through June 2019 inflation data for the 2020 revenue requirement calculations and July 2018 through June 2020 inflation data for the 2021 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 determines the 2020 and 2021 Inflation Factors based on prior year's BC-CPI and BC-AWE used to calculate Formula O&M discussed in Section 6 and Formula Growth Capital discussed in Section 7. Section 2.3 determines the average customer count used to calculate the Formula O&M discussed in Section 6 and provides the gross customer additions forecast used to calculate the Formula Growth Capital discussed in Section 7.

2.2 *INFLATION FACTOR CALCULATION SUMMARY*

In the MRP Decision, the BCUC approved an Inflation Factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FEI uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 (formerly CANSIM 326-0020) for CPI-BC and Table 14-10-0223-01 (formerly CANSIM 281-0063) to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of May 2020 has been used as a placeholder for June 2020 for AWE-BC, as results for this period have not been released by Statistics Canada. Once results for this period are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

---

9 FEI's most recent year of completed actuals is 2019 so that ratio has been used for both the 2020 and 2021 I-Factor calculation. The 2022 I-Factor calculation will be based on 2020 actual non-labour / labour split.

10 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 actual customers in the following years.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2019 labour weighting of 52 percent, the calculation of the 2020 I-Factor is (2.692 percent x 48 percent) + (2.881 percent x 52 percent) = 2.790 percent, and the calculation of the 2021 I-Factor is (1.596 percent x 48 percent) + (5.946 percent x 52 percent) = 3.858 percent.

Table 2-1: I-Factor Calculation

		Table: 18-10-0004-01	*Table: 14-10-0223-01*	12 Mth Average				Last Completed			
Line No.	Date	BC CPI index	BC AWE $	CPI index	AWE $	CPI %	AWE %	Non Labour %	Labour %	I-Factor %	MRP Year
1	Jul-2017	125.6	939.88								
2	Aug-2017	125.9	939.79								
3	Sep-2017	125.7	951.51								
4	Oct-2017	125.6	950.29								
5	Nov-2017	125.9	952.12								
6	Dec-2017	125.2	958.25								
7	Jan-2018	126.1	957.22								
8	Feb-2018	127.0	962.48								
9	Mar-2018	127.4	963.99								
10	Apr-2018	127.7	953.93								
11	May-2018	128.4	956.99								
12	Jun-2018	128.6	967.63	126.6	954.51						
13	Jul-2018	129.7	974.29								
14	Aug-2018	129.6	979.82								
15	Sep-2018	128.9	975.65								
16	Oct-2018	129.4	978.07								
17	Nov-2018	128.9	979.83								
18	Dec-2018	129.0	976.63								
19	Jan-2019	129.1	973.10								
20	Feb-2019	129.8	974.09								
21	Mar-2019	130.7	986.67								
22	Apr-2019	131.2	991.01								
23	May-2019	131.8	1,001.50								
24	Jun-2019	131.9	993.45	130.0	982.01	2.692%	2.881%	48%	52%	2.790%	2020
25	Jul-2019	132.4	996.11								
26	Aug-2019	132.2	1,003.60								
27	Sep-2019	132.0	1,008.09								
28	Oct-2019	132.2	1,015.74								
29	Nov-2019	131.8	1,012.40								
30	Dec-2019	131.7	1,014.52								
31	Jan-2020	132.1	1,025.61								
32	Feb-2020	132.9	1,025.17								
33	Mar-2020	132.3	1,029.38								
34	Apr-2020	131.2	1,106.54								
35	May-2020	131.5	1,123.79								
36	Jun-2020	132.6	1,123.79	132.1	1,040.40	1.596%	5.946%	48%	52%	3.858%	2021

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine Formula O&M, and a forecast of gross customer additions to determine Formula Growth Capital.

The calculation of the average customers used to determine Formula O&M is summarized in the table below.

Table 2-2: Average Customer (AC) Growth Factor Calculation[11]

Line No.		2020	2021	Reference
1	Average Customer Forecast - Prior Year	1,031,862	1,043,259	
2	Average Customer Forecast - Test Year	1,043,259	1,053,292	Schedule 19, Row 30
3	Average Customer Change	11,397	10,033	Line 2 - Line 1
4	Customer Growth Factor Multiplier	75%	75%	
5	Change in Customers - Rate Setting Purposes	8,548	7,525	Line 3 x Line 4
6				
7	*Average Customer Continuity for Rate Setting Purposes*			
8	Average Customer Forecast - Prior Year	1,031,862	1,040,410	Prior Year Line 10
9	Change in Customers - Rate Setting Purposes	8,548	7,525	Line 5
10	Average Customer Forecast - Rate Setting Purposes	1,040,410	1,047,935	Line 8 + Line 9

The forecast for FEI's Gross Customer Additions for determination of the Formula Growth Capital is provided in the table below.

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

	2020	2021
Gross Customer Additions	18,000	16,000

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 forecast, FEI has assumed that the following activities remain at the same or similar levels to the prior years: the market capture rate for new construction at 82 percent, conversion activity comprises approximately 19 percent of the gross additions, and there are no further policy or building code impacts. The forecast for 2020 has been developed by starting with June 2020 YTD additions and forecasting new additions for the remainder of the year. Forecasting for the remainder of 2020 and for the 2021 year is undertaken by reviewing information contained in FEI's customer relationship management software (CRM) (leads, connection requests, timing of connection requests, etc.) along with interactions with builders, developers, and contractors. With forecasts that are further out in time, such as 2021, FEI uses market information such as building permits, forecast housing starts and completions as well as any knowledge of policy or building code changes that may affect specific municipalities. The

[11] Line 1 for 2020 (Average Customer Forecast – Prior Year) is 2019's actual average customer count.

impact of the COVID-19 pandemic over the coming months and years creates greater uncertainty in the forecast of gross customer additions, which will be corrected in subsequent years with the BCUC approved true-up mechanism.

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine Formula O&M and Formula Growth Capital for 2020 and 2021 is provided in Table 2-4, including the I-Factors calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of customers determined in Section 2.3.

Table 2-4: Summary of Formula Drivers

Line No.	Particulars	2020	2021	Reference
1	CPI	2.692%	1.596%	Table 2-1, Lines 24 and 36
2	AWE	2.881%	5.946%	Table 2-1, Lines 24 and 36
3				
4	Non Labour	48%	48%	Table 2-1, Lines 24 and 36
5	Labour	52%	52%	Table 2-1, Lines 24 and 36
6				
7	CPI/AWE Inflation	2.790%	3.858%	(Line 1 x Line 4) + (Line 2 x Line 5)
8				
9	Productivity Factor	-0.500%	-0.500%	Order G-165-20
10				
11	Net Inflation Factor	2.290%	3.358%	Line 7 + Line 9
12				
13	Average Customers for Formula O&M purposes	1,040,410	1,047,935	Table 2-2, Line 10
14				
15	Gross Customer Additions for Formula Growth Capital purposes	18,000	16,000	Table 2-3, Line 1

In summary, the Net Inflation Factors for 2020 and 2021 are 2.290 percent and 3.358 percent, respectively. Formula O&M for 2020 and 2021 is determined using average customers of 1,040,410 and 1,047,935, respectively. Formula Growth Capital for 2020 and 2021 is determined using gross customer additions of 18,000 and 16,000, respectively.

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. The total demand is a combination of energy demand from residential, commercial and industrial customers.

FEI is forecasting minimal change in consumption in the 2020 Projected (2020P) forecast (which includes actuals to June 30, 2020) compared to the 2019 Approved forecast. The total 2020P normalized[12] demand is projected to be approximately 235.4 PJs, which is nearly equal to the 2019 Approved demand. Based on the 2019 Approved rates for each customer class, FEI's 2020 Projected revenue forecast is $1,299 million and FEI's 2020 gross margin forecast is $849 million.

FEI is forecasting a decrease in consumption in the 2021 Forecast (2021F) compared to the 2020 Projected forecast. The 2021F normalized load is forecast to be approximately 233.6 PJs, which is a 1.8 PJ decrease compared to 2020 Projected forecast. The decrease in 2021F is due to decreased loads in the residential and industrial classes. Based on the 2020 Approved Interim rates for each customer class, FEI's 2021 revenue forecast is $1,391 million and FEI's 2021 gross margin forecast is $875 million.

FEI has provided further information supporting its demand forecast in Appendix A of the Application.

3.2 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting method followed by FEI in previous years, the demand forecast relies on three components:

- the residential and commercial net customer additions forecast;[13]
- the residential and commercial use per customer (UPC) forecast; and
- the Industrial Forecast.

The demand forecast for residential and commercial customers is based on forecasts for the number of customers and UPC rates. Specifically, the average UPC is estimated for customers under Rate Schedules 1, 2, 3 and 23 and then multiplied by the corresponding forecast of the number of customers (opening number of customers plus average net customer additions during the year) in these rate schedules to derive energy consumption.

[12] For the 2020P demand, FEI replaced the first six months of projected normalized load with actual load.
[13] The net customer additions are the year-over-year change in the total number of customer additions over the past three years.

The forecast of industrial energy demand is based upon customer-specific forecasts obtained through an Industrial Survey, as discussed in Section 3.3.3.

See Appendix A3 for a detailed description of FEI's demand forecast methods.

The forecast Natural Gas for Transportation (NGT) Demand is for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) volumes. The NGT demand forecast is discussed is Section 3.3.4 below.

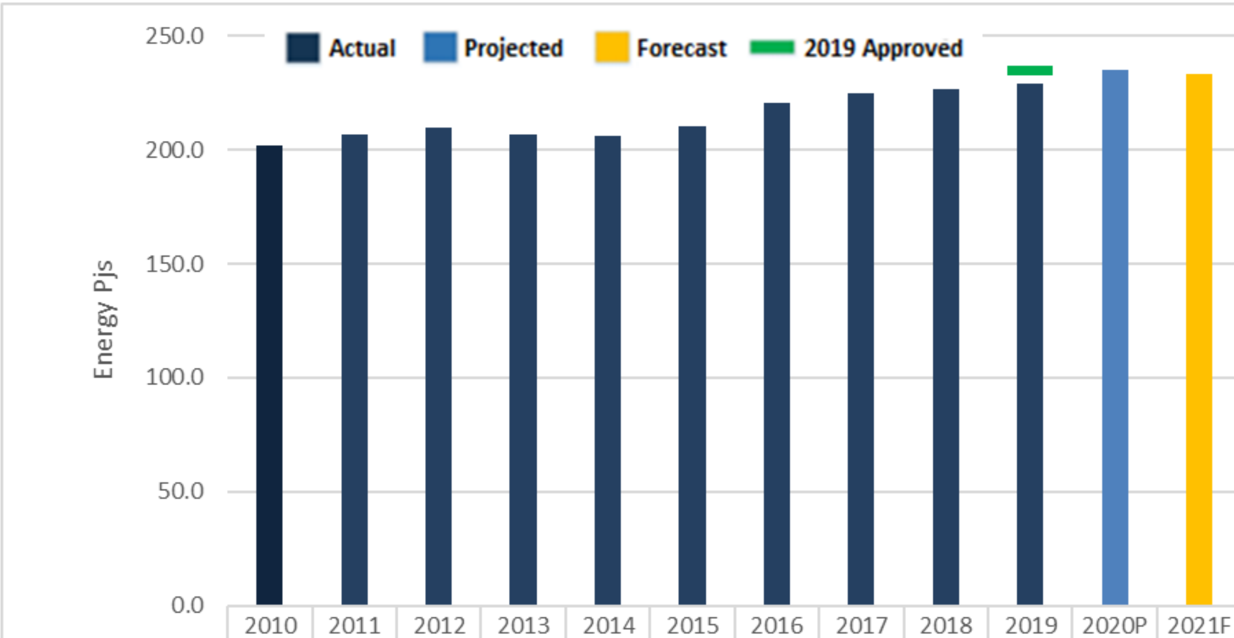
The following sections set out the results of the demand forecast. In the figures provided in the demand forecast sections, the following three time periods are shown:

- 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 2019 calendar year.
- Projected Year: The Projected Year (2020P) is the year prior to the first forecast year. The Projected Year is forecast based on the latest years of actual data available (through 2019). The January through June forecast values were then replaced with Actual 2020 values.
- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2021 (2021F).
- Also included in the figures in this section is the prior year's forecasts, 2019F as presented in the Annual Review for 2019 Rates.

3.3 *DEMAND FORECAST*

FEI's total energy demand consists of the weather normalized residential and commercial demand and the industrial and NGT demand. As shown in Figure 3-1 below, the total load is projected to remain flat at 235.4 PJs in 2020, compared to 2019 Approved, and is forecast to be 233.6 PJs in 2021F, down 1.8 PJ from 2020P.

Figure 3-1: Total Energy Demand in PJs



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Total Demand	201.9	206.7	209.9	206.6	206.5	210.6	220.6	225.0	227.3	229.0	235.4	233.6
2019 Approved										235.4		

The residential, commercial, industrial, and NGT demand forecasts are provided separately in the following subsections.

3.3.1 Residential

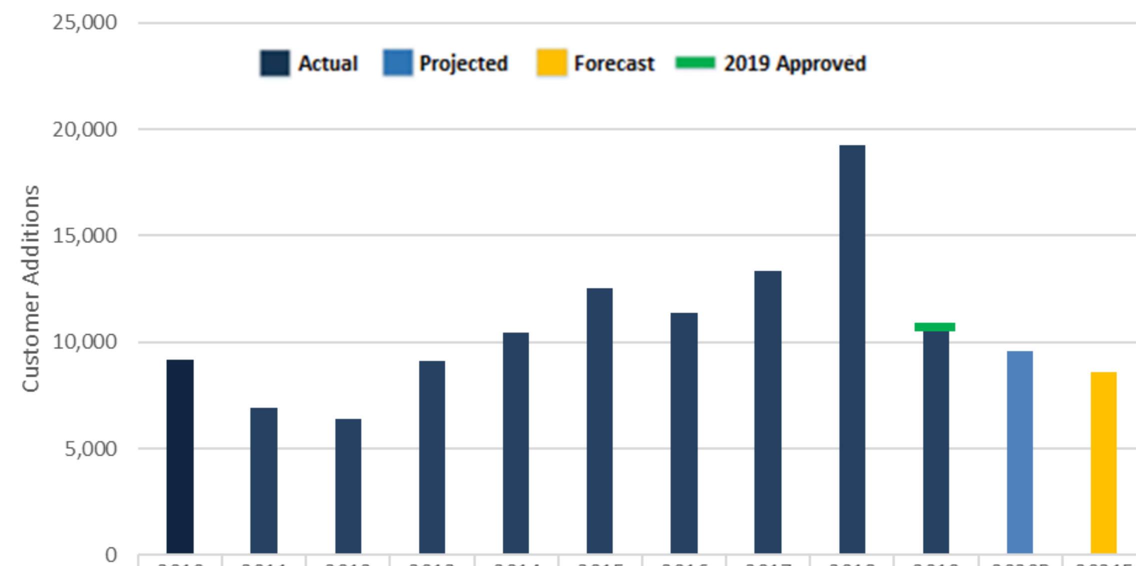
3.3.1.1 Residential Customer Additions

Consistent with past practice, FEI uses the Conference Board of Canada (CBOC) housing starts forecast as a proxy for residential net customer additions. The CBOC data used for the forecast, in Appendix A3, was issued prior to the start of the pandemic and, at the time of this filing, the CBOC had not issued an updated single or multi-family forecast. The 2021 forecast of 8,569[14] additions reflects a lower CBOC housing starts forecast for BC than experienced in 2019 or projected for 2020. In deriving the 2020 projection, the first six months of the forecast of customer additions were replaced by actual values. As shown in Figure 3-2, residential customer additions are forecast to decrease by 1,145 in 2020P compared to 2019 Approved and decrease by 1,010 additions in 2021F compared to 2020P.

Figure 3-2 provides the residential net customer additions for 2010 through 2021.

[14] Difference between December 2020P customer count and December 2021F customer count.

Figure 3-2: Residential Net Customer Additions



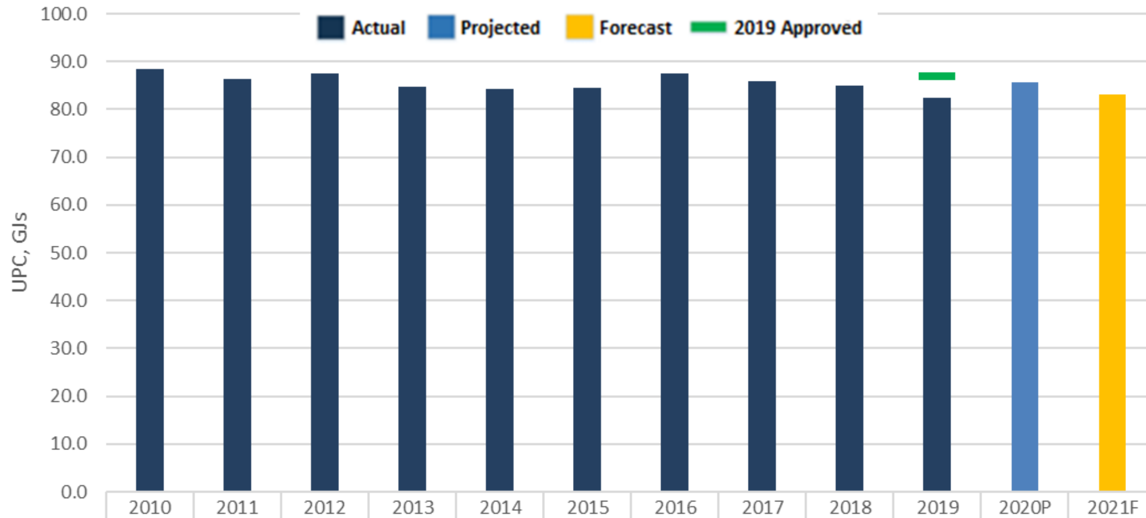
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 1	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	9,579	8,569
2019 Approved										10,724		

3.3.1.2 Residential UPC

The residential UPC forecast was developed using the exponential smoothing (ETS) method with the most recent 10 years of historical weather-normalized UPC, described in Appendix A3. For 2020, the first six months of the forecast were replaced by actual values.

As shown in Figure 3-3, the residential UPC is forecast to decrease by approximately 1.3 GJs in 2020P compared to 2019 Approved and then decrease by approximately 2.6 GJs in 2021F compared to 2020P.

Figure 3-3: Rate Schedule 1 UPC

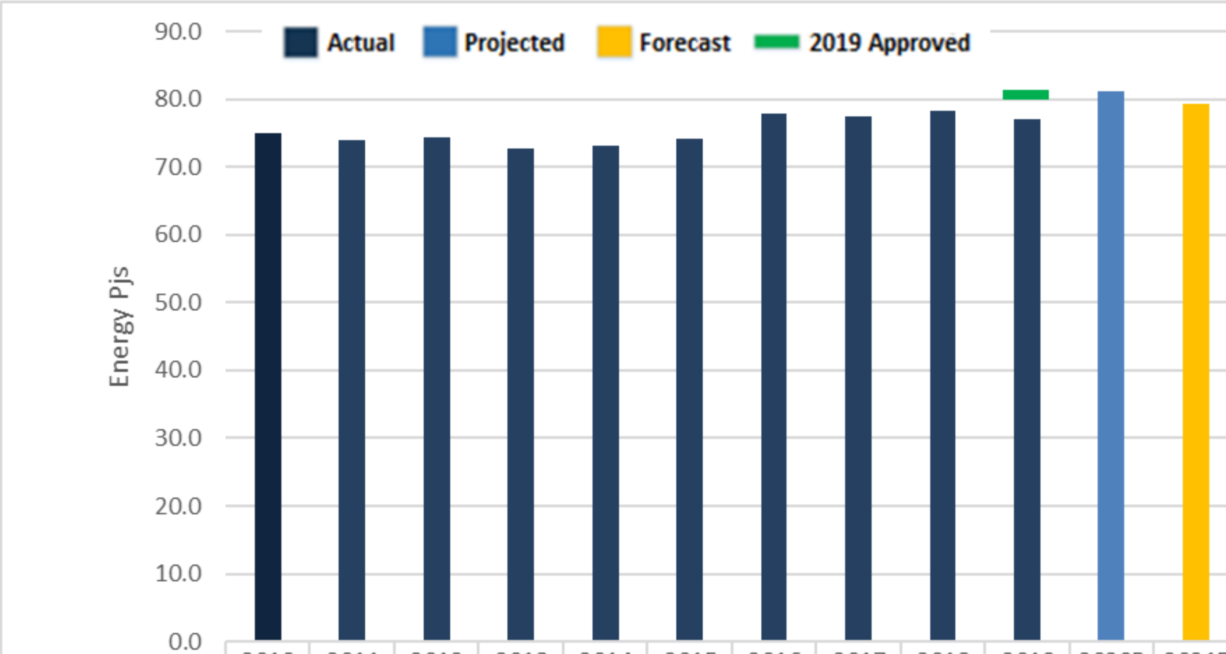


	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	85.7	83.1
2019 Approved										87.0		

3.3.1.3 Residential Demand

Taking into account the customer additions and UPC forecasts described above, and as shown in Figure 3-4 below, residential demand is forecast to increase by 0.3 PJ in 2020P compared to 2019 Approved, and then decrease by 1.8 PJ in 2021F.

Figure 3-4: Normalized Residential Demand



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 1	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.1	79.3
2019 Approved										80.8		

3.3.2 Commercial

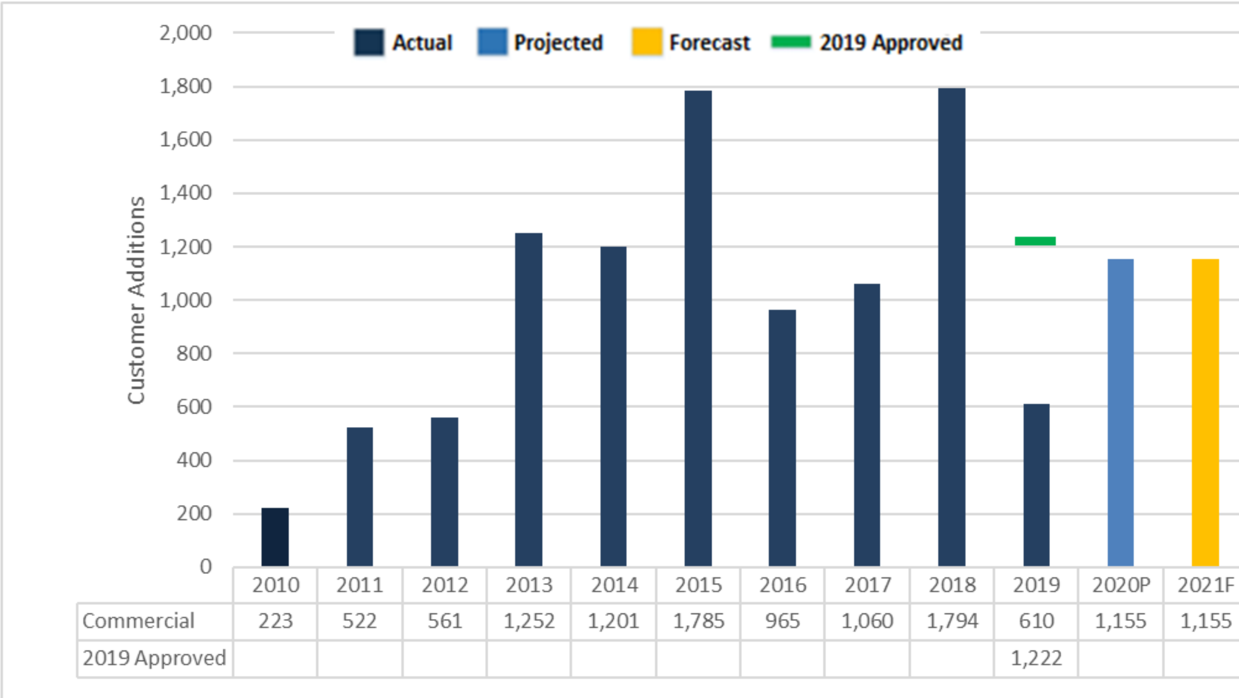
3.3.2.1 Commercial Customers

The commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2017 to 2019). As there was a relatively large migration of Rate Schedule 23 transportation customers to bundled service under Rate Schedule 3 over the past years, these two rate classes were forecast together as "large commercial" and the total allocated to the two rate classes proportional to the current composition. For 2020, the first six months of the forecast were replaced by actual values.

As shown in Figure 3-5 below, commercial customer additions are forecast to decrease by 67[15] customers in 2020P compared to 2019 Approved and remain flat in 2021F.

[15] Difference between December 2020P customer count and December 2021F customer count.

Figure 3-5: Commercial Net Customers Additions

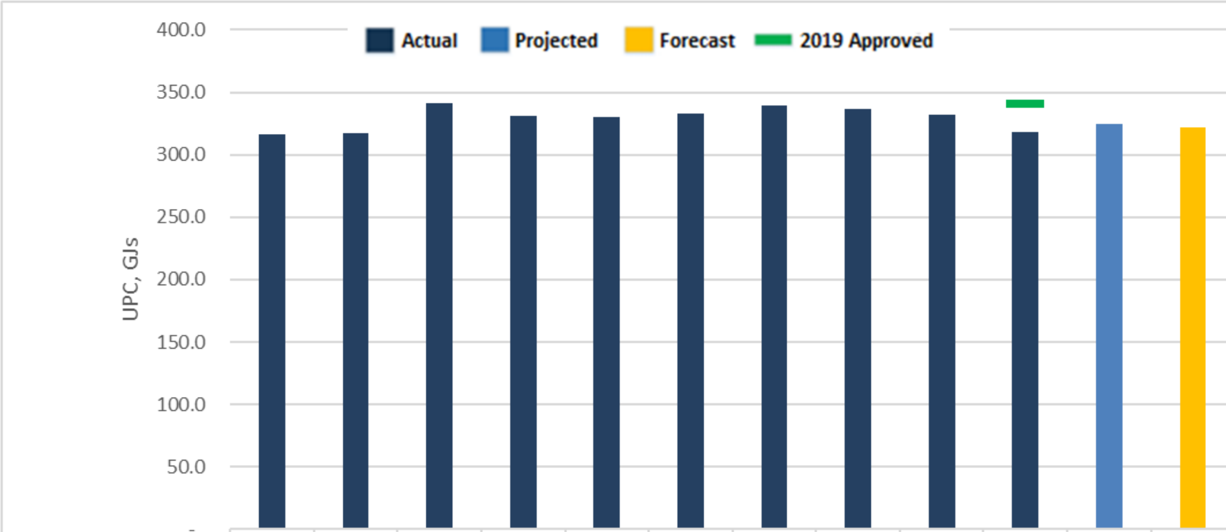


3.3.2.2 Commercial UPC

The commercial UPC forecast was developed using the ETS method, considering the most recent 10 years of historical weather-normalized UPC. For 2020, the first six months of the forecast were replaced by actual values.

As shown in Figure 3-6, the Rate Schedule 2 UPC is forecast to decrease by 16.4 GJs in 2020P compared to 2019 Approved and decrease 3.1 GJs in 2021F compared to 2020P.

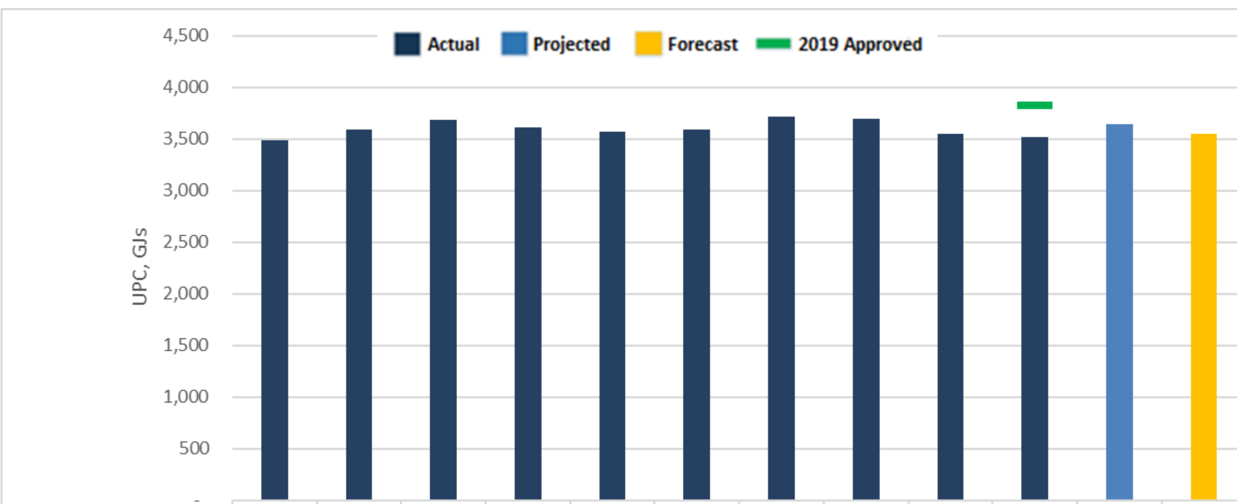
Figure 3-6: Rate Schedule 2 UPC



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 2	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	324.9	321.8
2019 Approved										341.3		

As shown in Figure 3-7, the Rate Schedule 3 UPC is forecast to decrease by 183 GJs in 2020P compared to 2019 Approved, and decrease 97 GJs in 2021F compared to 2020P.

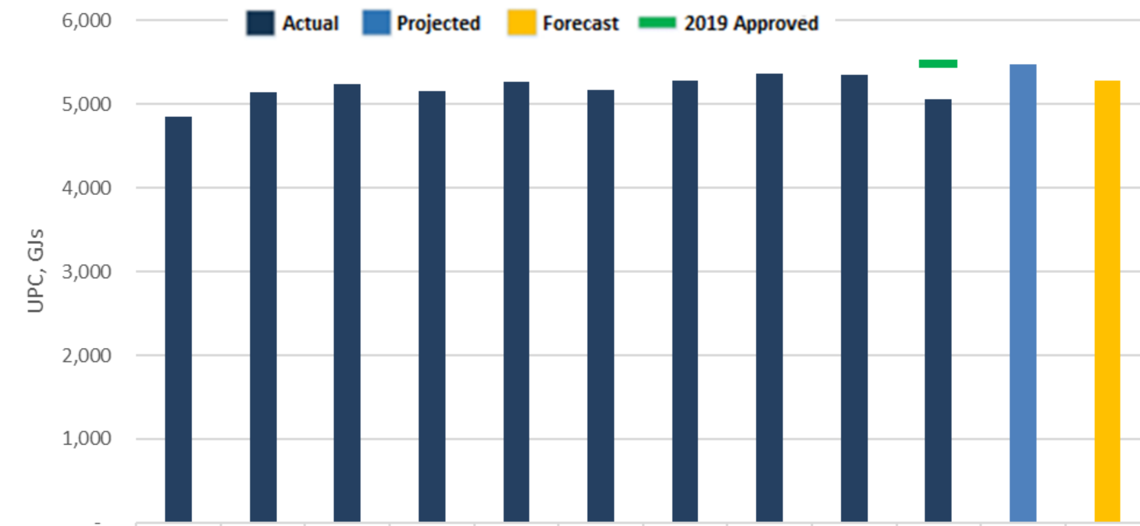
Figure 3-7: Rate Schedule 3 UPC



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 3	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	3,648	3,551
2019 Approved										3,831		

As shown in Figure 3-8, the Rate Schedule 23 UPC is forecast to decrease by 12 GJs in 2020P compared to 2019 Approved and then decrease by 202 GJs in 2021F compared to 2020P.

Figure 3-8: Rate Schedule 23 UPC

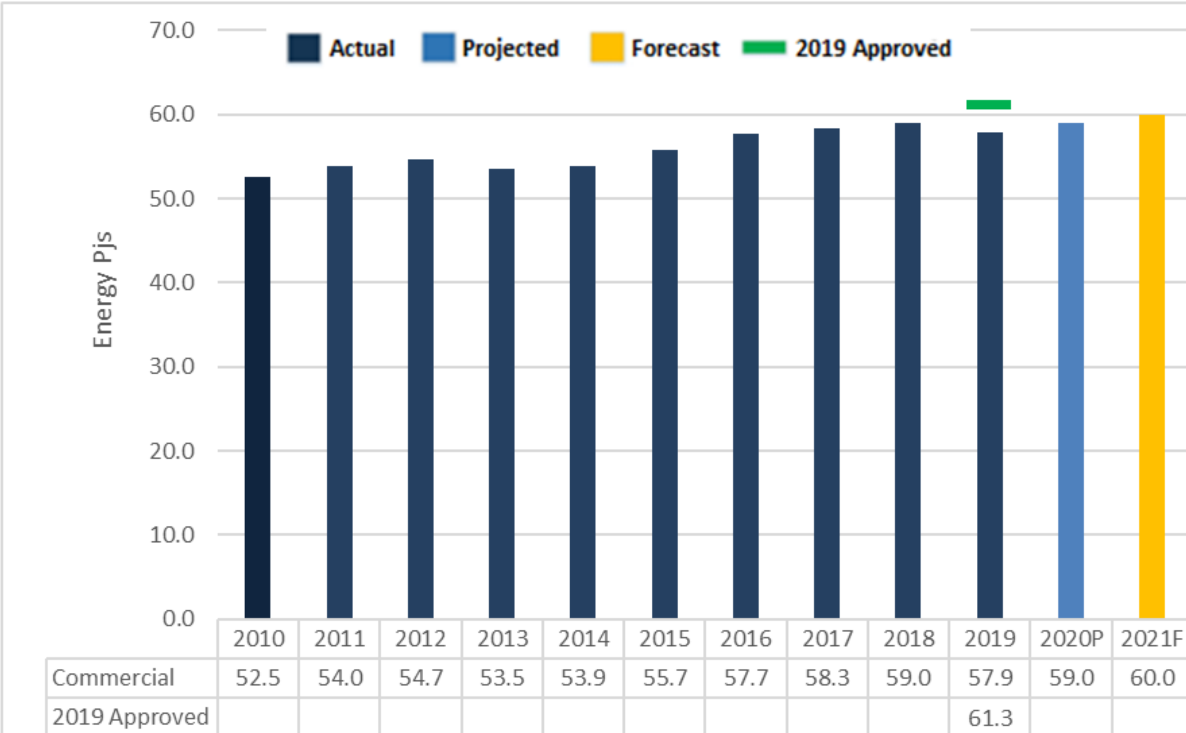


	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 23	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051	5,480	5,278
2019 Approved										5,492		

3.3.2.3 Commercial Demand

Taking into account the customer additions and UPC forecasts described above, and as seen in Figure 3-9 below, commercial demand is forecast to decrease by 2.3 PJs in 2020P compared to 2019 Approved and then grow by 1 PJ in 2021F compared to 2020P.

Figure 3-9: Commercial Demand



3.3.3 Industrial Demand

The 2020P demand for industrial customers was developed using 2020 actual demand from January through June and 2019 actual demand for July through December.

The 2021F demand for industrial customers was forecast using the Industrial Survey.

For the 2021 Forecast, customers responded to the survey in June and July of 2020. The survey was launched as close as possible to the filing date to mitigate potential variances in the forecast, particularly from Rate Schedule 22 customers. The survey needed to be completed by July 6, 2020 to allow sufficient time for internal review of the results, loading of data in FEI's Forecasting Information System (FIS), preparing the forecast and drafting the Application. Since the survey requires approximately five weeks to complete, it was launched on June 5, 2020.

As shown in Table 3-1 below, the response rate achieved in 2020 was 46.7 percent of industrial customers, representing approximately 89.3 percent of industrial volumes. There was no reply from 44.5 percent of industrial customers, who received the survey and three reminder notifications; this group represents only 9.5 percent of the industrial demand. Surveys could not be delivered to 8.8 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 1.2 percent of the total industrial load.

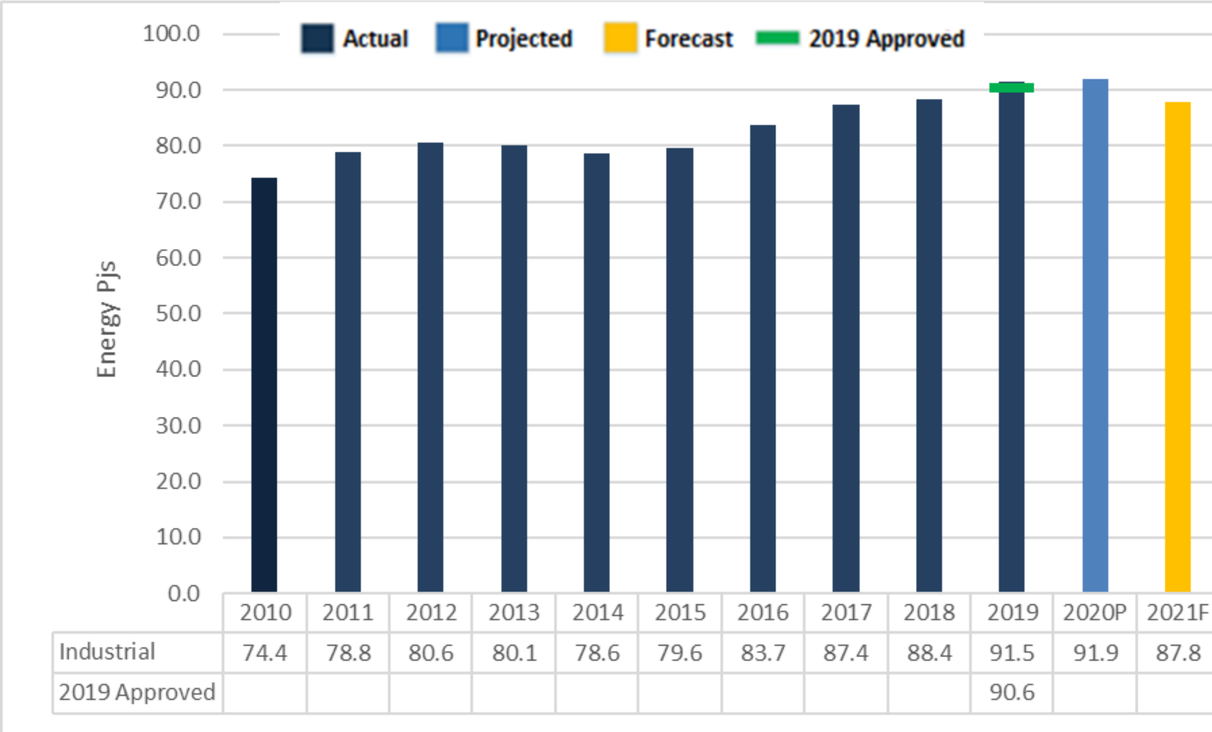
Table 3-1: Industrial Survey Response Rates

2020 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	46.7%	89.3%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	44.5%	9.5%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	8.8%	1.2%
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 11 percent of the total industrial demand) was set to equal 2019 Actual consumption.

As seen in Figure 3-11 below, the demand from the industrial rate schedules is forecast to increase by 1.3 PJ in 2020P compared to 2019 Approved and then decrease 4.1 PJs in 2021F comparted to 2020P.

Figure 3-10: Industrial Demand[16]



3.3.4 Natural Gas for Transportation and LNG Demand

This section summarizes the CNG and LNG demand forecasts related to demand from NGT customers and non-NGT related demand for LNG supplied under Rate Schedule 46, including power generation as well as export customers. Table 3-2 below provides the 2019 Approved and Actual, 2020 Projection and 2021 Forecast of total NGT and non-NGT demand. As directed in Order G-86-15, FEI has included the forecast of demand provided to customers under spot purchase agreements (i.e., not under firm take-or-pay commitments) in the total NGT and non-NGT demand.

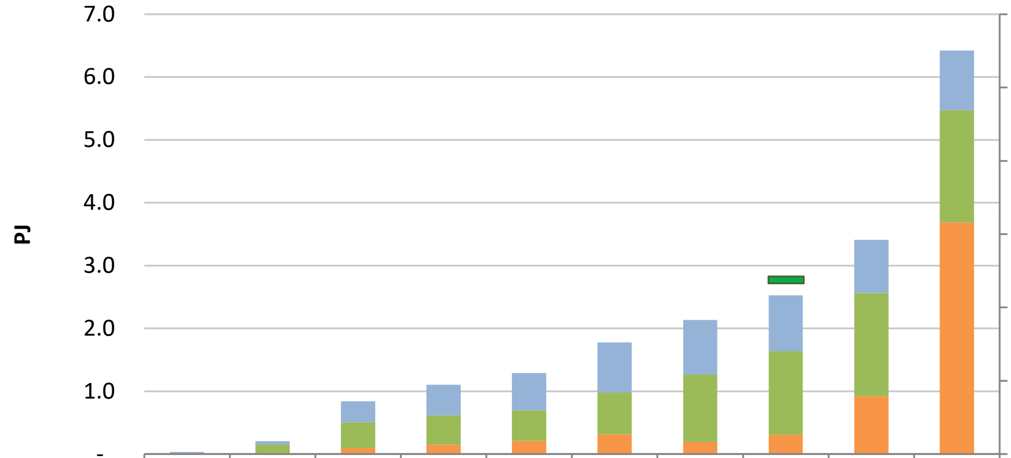
Table 3-2: FEI Total Natural Gas Demand for NGT and non-NGT (GJ per year)

GJ	2019 Approved	2019 Actual	2020 Projected	2021 Forecast
CNG	1,074,309	885,913	845,199	951,388
LNG	1,526,049	1,335,079	1,643,386	1,784,400
Total NGT Demand	**2,600,358**	**2,220,992**	**2,488,585**	**2,735,788**
Non-NGT Demand	170,460	305,297	922,202	3,685,185
Total NGT and Non-NGT Demand	**2,770,818**	**2,526,289**	**3,410,787**	**6,420,973**

The following figure shows the composition of the 2011 to 2019 Actual, 2019 Approved, 2020 Projected, and 2021 Forecast annual demand for CNG (RS 3/5/23/25/6P) and LNG (RS 46), including a breakdown of LNG between NGT and non-NGT.

[16] Excludes NGT.

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[17]



	2011A	2012A	2014A	2015A	2016A	2017A	2018A	2019A	2020P	2021F
RS 3/5/23/25/6P - CNG (NGT)	0.0	0.1	0.3	0.5	0.6	0.8	0.9	0.9	0.8	1.0
RS 46 - LNG (NGT)	0.0	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.6	1.8
RS 46 - LNG (Non-NGT)	-	-	0.1	0.1	0.2	0.3	0.2	0.3	0.9	3.7
2019 Approved								2.8		
Total CNG & LNG	0.0	0.2	0.8	1.1	1.3	1.8	2.1	2.5	3.4	6.4

The 2020 Projected demand is approximately 0.9 PJ higher than the 2019 Actual demand of 2.5 PJs. Of this 0.9 PJ increase, approximately 0.3 PJ (or approximately 30.2 percent) is attributed to demand that serves NGT customers while the rest of the increase is attributed to non-NGT demand involving LNG exports (approximately 0.6 PJ or 69.8 percent).

For 2021, the CNG demand for NGT customers is forecasted to increase by approximately 0.11 PJ (approximately 13 percent) from the 2020 Projected level. This is primarily attributable to incremental load from existing customers and two new CNG stations to be in-service starting in mid-2020 with demand ramp up by 2021. The LNG demand for NGT customers is forecast to increase by approximately 0.14 PJ (approximately 9 percent) from the 2020 Projected level which is primarily attributed to increased volumes from BC Ferries and Seaspan due to two additional fleet vessels.

For non-NGT demand, FEI expects the 2021 Forecast will continue to increase as a result of expanded LNG exports. This is an approximately 2.7 PJ increase from the 2020 Projected level.

3.4 *REVENUE AND MARGIN FORECAST*

The forecast of revenues and margins has been developed by considering the total 2020 Projected and 2021 Forecast energy in GJ applied at 2019 and 2020 approved delivery rates[18]

[17] Forecast includes all NGT related CNG and LNG demand, and Other LNG demand inclusive of contract and excess demand flowing through stations as well as spot volumes and third party station CNG/LNG volumes.

[18] At 2019 Approved delivery rates and 2020 Interim Approved delivery rates.

and applicable 2020 Approved commodity and storage and transport rates (most recent approved commodity and storage and transport rates).

3.4.1 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 2019 Approved, 2019 Actual, 2020 Projected, and 2021 Forecast revenue.

Table 3-3: Forecast Sales Revenue at Approved Rates

Revenue ($ millions)	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
Residential [1]	709.672	718.167	739.480	770.705
Commercial [2]	376.335	383.029	391.697	425.484
Industrial [3]	127.432	145.155	167.970	194.664
Total	**1,213.439**	**1,246.351**	**1,299.148**	**1,390.853**

Notes:
[1] Rate Schedule 1.
[2] Rate Schedules 2, 3, 23.
[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Joint Venture, BC Hydro Island Generation.

3.4.2 Margin

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 2019 Approved, 2019 Actual, 2020 Projected, and 2021 Forecast margin, by customer segment, at approved delivery rates[19].

Table 3-4: Forecast Gross Margin at Approved Rates

Margin ($ millions)	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
Residential [1]	491.826	476.454	496.085	499.176
Commercial [2]	238.980	228.756	232.324	241.074
Industrial [3]	113.351	116.637	120.920	134.668
Total	**844.157**	**821.847**	**849.330**	**874.918**

[19] Ibid.

Notes:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Joint Venture, BC Hydro Island Generation.

Variances between the delivery margin forecast in this section and actual delivery margin are captured in either the Revenue Stabilization Adjustment Mechanism (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.

3.5 *SUMMARY*

FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years, or – in the case of the ETS method – represent a method that has been demonstrated to be superior to past practice as reported previously to the BCUC. FEI's forecast provides a reasonable estimate of future natural gas demand for 2020 and 2021. Based on these methods, FEI is forecasting a minimal change in consumption in 2020P compared to 2019 Approved, followed by a decrease in consumption in 2021F of 1.8 PJs compared to 2020P. Based on the 2019 and 2020 approved rates for each customer class, FEI's 2020 and 2021 revenue forecast is $1,299 million and $1,391 million respectively.

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. With the exception of the CMAE costs, as further explained below and in Appendix B, the Company is not requesting approval of forecast gas costs with this Application. Instead, any rate changes related to the flow through of gas costs 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.

Commencing with the 2021 CMAE budget, FEI will be filing for approval of the CMAE budget as part of the Annual Review filings. This approach is in compliance with the BCUC's determination in decision and Order G-79-14. Please see Appendix B for a detailed discussion of the CMAE budget. In summary, and as included in the Approvals Sought (Section 1.2, item 7) of the Application, FEI is requesting BCUC approval of the following related to CMAE, effective January 1, 2021:

- Approval of the 2021 CMAE Budget of $5.524 million, as set out in Schedule 1 of Appendix B; and
- Approval of the allocation of the 2021 CMAE between the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

While the Company is not requesting approval of forecast gas costs (other than CMAE) with 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 forecast described in Section 3, by the August 1, 2020 unit gas cost recovery charges for each rate schedule.

The natural gas commodity cost recovery rate for the Mainland and Vancouver Island service area became effective August 1, 2020 pursuant to Order G-189-20, dated July 16, 2020. The natural gas storage and transport rates and riders, also known as the midstream cost recovery rates and MCRA rate riders, for the Mainland and Vancouver Island service area became effective January 1, 2020 pursuant to Order G-306-19, dated November 28, 2019.

The propane cost recovery rates for Revelstoke became effective August 1, 2020 pursuant to Order G-191-20, dated July 16, 2020.

The table below sets out the forecast cost of gas at existing rates, by rate schedule group.

Table 4-1: Forecast Cost of Gas at Existing Rates[20]

Cost of Gas ($ millions)	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
Residential [1]	217.846	241.713	243.395	271.529
Commercial [2]	137.355	154.273	159.373	184.410
Industrial [3]	14.081	28.518	47.050	59.996
Total	**369.282**	**424.504**	**449.818**	**515.935**

Notes:

1. Includes Rate Schedules 1 volumes
2. Includes Rate Schedules 2, 3, 23 volumes
3. Includes Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27 volumes

The natural gas storage and transport, or midstream, component of the cost of gas includes the costs for the contracted third party pipeline and storage resources, seasonal and peaking supply, and also includes costs for unaccounted for gas (UAF).

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Sources of UAF comprise, but are not limited to, system leakage, lost gas (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 included in the cost of gas and recovered from core customers[21] via the gas cost rates. The cost of UAF related to the Transportation Service rate classes is included in the determination of the delivery rates to facilitate recovery of UAF costs from Transportation Service customers, as they do not pay midstream charges.

[20] Biomethane commodity costs are excluded from the table because they are allocated directly to the Biomethane Variance Account.

[21] 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 MRP Decision (page 74), FEI was approved for forecast variances in certain components of Other Revenue 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 2014-2019 PBR Plan term.

As shown in the table below, FEI is forecasting Other Revenue to decrease from the amount approved for 2019, primarily due to a decrease in SCP Third Party revenue.

Table 5-1: Other Revenue Components

Other Operating Revenue, ($ millions)				
	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
Late Payment Charge	2.549	2.778	1.671	2.954
Application Charge	1.925	1.707	1.965	1.984
NSF Returned Cheque Charges	0.028	0.037	0.028	0.028
Other Recoveries	0.288	0.353	0.288	0.288
NGT Related Recoveries	4.378	3.946	3.792	3.698
Biomethane Other Revenue	0.614	0.614	0.937	0.951
SCP Third Party Revenue	17.072	17.072	10.877	14.053
LNG Capacity Assignment	18.039	18.039	18.039	18.039
Total Other Operating Revenue	**44.893**	**44.546**	**37.597**	**41.995**

In the following sections, FEI summarizes the methods used to forecast the line items included in the table above, and also addresses the largest components of Other Revenue, the SCP Third Party Revenue and the LNG Capacity Assignment.

5.2 OTHER REVENUE COMPONENTS

5.2.1 Late Payment Charge

FEI implemented a number of customer relief measures in 2020 during the COVID-19 pandemic, including the suspension of Late Payment Charges. As a result, 2020 Projected Late Payment Charges are expected to be lower than 2019 Approved. In 2021, FEI expects the amount of Late Payment Charges to return to a more normal level.

The 2021 Forecast for Late Payment Charges as part of Other Revenue is based on the 2017 to 2019 average of Late Payment Charges earned. The calculation for 2020 Projected includes six months of actual results, with the remaining six months projected based on the prorated average of the actual 2017 to 2019 Late Payment Charges.

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 2020 Projected and 2021 Forecast amounts are expected to be in line with 2019 levels.

5.2.3 NSF Returned Cheque Charges and Other Recoveries

The 2020 Projected and 2021 Forecast amounts for NSF Returned Cheque Charges and other miscellaneous income items are based on 2019 levels.

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing 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 will affect ROE and will be subject to earnings sharing. Variances in the NGT Tanker Rental Revenue and CNG & LNG Service Revenues are treated as Flow-through with the variances being captured in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2020 and 2021 NGT Related Recoveries

NGT Related Recoveries, ($ millions)				
	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
NGT Overhead and Marketing Recovery	$ 0.325	$ 0.305	$ 0.284	$ 0.258
NGT Tanker Rental Revenue	0.680	0.582	0.569	0.774
CNG & LNG Service Revenues	3.373	3.059	2.939	2.666
Total NGT Related Recoveries	**$ 4.378**	**$ 3.946**	**$ 3.792**	**$ 3.698**

The following subsections discuss each of the NGT related recoveries.

5.2.4.1 NGT Overhead and Marketing Recovery

Pursuant to Order G-78-13, FEI has included a forecast of overhead and marketing (OH&M) recovery from FEI's NGT fuelling station customers for both 2020 and 2021. As shown in Table 5-3 below, the total projection of NGT OH&M revenue for 2020 is $0.284 million and the forecast NGT OH&M revenue for 2021 is $0.258 million. This revenue is calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[22] 2020 Projected and 2021 Forecast CNG and LNG sales volumes, respectively.

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

NGT Overhead and Marketing Revenue	2019 Approved	2019 Actual	2020 Projected	2021 Forecast
Applicable Volume (GJ)	624,316	587,433	545,537	495,745
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.325**	**$ 0.305**	**$ 0.284**	**$ 0.258**

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)

Tanker Rental Revenue	2019 Approved	2019 Actual	2020 Projected	2021 Forecast
Standard Tanker Rental Deliveries	627	430	366	360
Rate ($/Delivery)	$ 279	$ 283	$ 289	$ 295
Sub Total ($ millions)	$ 0.175	$ 0.122	$ 0.106	$ 0.106
Tridem Tanker Rental Deliveries	112	-	-	-
Rate ($/Delivery)	$ 335	$ 339	$ 346	$ 353
Sub Total ($ millions)	$ 0.038	$ -	$ -	$ -
Marine Equipped Tridem Tanker Rental Deliveries	990	965	952	1,344
Rate ($/Delivery)	$ 472	$ 477	$ 487	$ 497
Sub Total ($ millions)	$ 0.467	$ 0.460	$ 0.464	$ 0.668
Total Tanker Rental Revenue ($ millions)	**$ 0.680**	**$ 0.582**	**$ 0.569**	**$ 0.774**

For the Standard tankers, the 2019 Actual rental revenue is approximately $0.053 million less than the 2019 Approved level primarily due to the closure of three LNG stations resulting in a decrease in the utilization of the standard tankers. FEI is expecting the Standard tanker rental revenue in 2020 and 2021 to be further reduced from the 2019 Actual level primarily due to spot customer deliveries and US deliveries continuing to be curtailed as a result of COVID-19.

For Tridem tankers, the 2019 Actual rental revenue is zero since these tankers are primarily used for long haul deliveries in Canada such as to the Yukon and these tankers are not permitted in the US (due to weight restrictions in the US). FEI does not expect Canadian deliveries to occur outside of British Columbia and is therefore expecting the 2020 Projected and 2021 Forecast Tridem tanker rental revenue to be zero.

For Marine equipped Tridem tankers, the 2019 Actual rental revenue is relatively the same as the 2019 Approved level with a variance of $0.007 million. FEI expects the rental revenues for Marine equipped Tridem tankers in 2020 to remain relatively the same level as 2019 with no growth as a result of COVID-19. For 2021, FEI is expecting recovering from COVID-19 for

[22] 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.

marine vessels and is forecasting 392 additional marine tanker deliveries from increased vessel consumption and an additional vessel put into service.

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., fuelling customer uses more than their contracted minimum take-or-pay volume).

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

CNG/LNG Service Revenue	2019 Approved	2019 Actual	2020 Projected	2021 Forecast
CNG Station	$ 1.836	$ 1.798	$ 1.840	$ 1.850
LNG Station	1.450	1.138	0.977	0.696
Subtotal - NGT Stations	**$ 3.286**	**$ 2.935**	**$ 2.817**	**$ 2.545**
Surrey Ops CNG Pump	0.086	0.124	0.122	0.121
Total	**$ 3.373**	**$ 3.059**	**$ 2.939**	**$ 2.666**

The 2019 Actual recoveries for CNG and LNG Stations are lower than the 2019 Approved levels by $0.038 million and $0.312 million, respectively. This is due to expected CNG customers not executing contracts with FEI and the closure of two LNG stations in 2019. CNG recoveries for 2020 Projected and 2021 Forecast are expected to increase slightly, while there will be a decrease in LNG recoveries due to the two LNG station closures and expiry of the Teck Coal Ltd. Agreement with FEI at the end of 2020. The 2019 Actual Surrey Ops CNG pump recoveries are higher than the 2019 Approved due to increased usage at the station. The 2020 Projected and 2021 Forecast for the Surrey Ops CNG pump recoveries are consistent with the 2019 Actual recoveries.

5.2.5 Biomethane Other Revenue

The Other Revenue amount of $0.937 million in 2020 and $0.951 million in 2021 shown in Table 5-1 above is the transfer from delivery margin to the Biomethane Variance Account (BVA) for the cost of service of the Biomethane capital assets.

In accordance with Order G-210-13, which approved the Biomethane Program on a permanent basis, the following delivery margin related costs must be included in the BVA[23]:

- Upgrading plant cost of service;
- Interconnection cost of service[24]; and

[23] The cost of procuring Biomethane supply does not need to be transferred because it is accounted for directly in the BVA.

- Program overhead costs.[25]

Commencing in 2020, the BCUC approved[26] the interconnection costs prior to Order G-210-13 to be recorded in the BVA consistent with costs incurred after Order G-210-13.

For 2020 and 2021, FEI has transferred the earned return on capital and tax components of the cost of service related to all Biomethane plant in service to the BVA by crediting 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: 2019, 2020 and 2021 SCP Revenue Components

Southern Crossing Pipeline Revenue, ($ millions)				
	Approved 2019	**Actual 2019**	**Projected 2020**	**Forecast 2021**
NW Natural	$ 5.763	$ 5.763	$ 4.154	$ -
MCRA	3.600	3.600	5.220	13.284
Net Other Mitigation - West to East Capacity	7.709	7.709	1.503	0.769
Total SCP Revenue	**$ 17.072**	**$ 17.072**	**$ 10.877**	**$ 14.053**

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

5.3.1 NW Natural

FEI is projecting reduced revenue from NW Natural in 2020 and forecasting no revenue from NW Natural in 2021, as FEI will not be renewing the firm service contract with NW Natural, formerly Northwest Natural Gas Co., which expires October 31, 2020. This contract was for 46.5 MMcfd of SCP east to west capacity and was approved by Order G-98-05.

As FEI explained in its 2020/2021 Annual Contracting Plan (ACP) as accepted by the BCUC in Letter L-31-20, dated June 5, 2020, FEI will be taking this SCP capacity back effective November 1, 2020 to meet load requirements and provide supply diversity for its customers. This means that the revenue from NW Natural will no longer be received for the last two months

24 Prior to Order G-165-20, the cost of service of Biomethane interconnection costs for projects introduced before Order G-210-13 were recorded in FEI's general cost of service.

25 Program costs as defined in Order G-210-13 include education, marketing, direct administration, cost of enrollment and the cost of IT upgrades.

26 Order G-165-20.

of 2020 and all of 2021. Taking this capacity back was FEI's only opportunity in the marketplace to diversify its portfolio, which is vital in light of the October 9, 2018 rupture and capacity restrictions imposed thereafter on the Westcoast T-South pipeline (T-South incident).

5.3.2 Midstream Cost Reconciliation Account (MCRA)

As shown in Table 5-6 above, 2019 Approved and 2019 Actual amounts include a $3.6 million per year credit in Other Revenue from the MCRA, which increases to $5.22 million in 2020 and $13.284 million in 2021. The 2019 amounts reflect the 58.5 MMcfd of SCP east to west capacity that FEI held as part of its midstream portfolio during that year. The increases in 2020 and 2021 are due to FEI's contract with NW Natural expiring November 1, 2020, and FEI taking back this capacity and holding it in its midstream portfolio, as explained in Section 5.3.1 above.

As the contract with NW Natural will continue until October 31, 2020, FEI seeks BCUC approval to continue debiting the MCRA and crediting Other Revenue in the amount of $300 thousand per month for the period of January 1, 2020 to October 31, 2020, during which FEI will continue to hold 58.5 MMcfd of SCP east to west capacity in its midstream portfolio.

Effective November 1, 2020, at which time the NW Natural contract will expire, FEI seeks BCUC approval for the debiting of the MCRA and crediting Other Revenue for the 105 MMcfd of SCP east to west capacity based on the cost of service valuation of $346.617 per MMcfd (equivalent to approximately $0.3059/GJ per day) as set out in Table 5-7 below.

In the subsections below, FEI explains the debits and credits to the MCRA in further detail.

Debiting MCRA and Crediting Other Revenue

The MCRA contains the midstream portfolio costs that FEI incurs to bring gas to its various interconnects from gas trading hubs such as Station 2 or AECO. This includes, for example, the costs to hold capacity on T-South and Aitken Creek storage costs. The customers that benefit from these costs are FEI's Sales Customers (not FEI's Transport Customers). Sales Customers purchase their gas from FEI, whereas Transport Customers purchase[27] their own gas and deliver it to FEI's various interconnects.[28] FEI uses the SCP pipeline, in part, to transport gas to its various interconnects. Therefore, some of the costs of the SCP pipeline in FEI's delivery cost must be moved to the MCRA so that only Sales Customers bear those costs through the Storage and Transport rate on their monthly bill (both Sales and Transport customers pay delivery rates). Moving the cost to the MCRA is achieved by crediting FEI's Other Revenue and debiting FEI's MCRA in each Annual Review.

Midstream Portfolio to Hold Additional Capacity

As noted above and explained in the 2020/2021 ACP, FEI will not be renewing the NW Natural SCP Agreement. With the expiration of the NW Natural contract for SCP east to west capacity

[27] A Transport Customer may purchase their gas directly or through a gas marketer.

[28] FEI then takes possession of the Transporters gas and moves it across FEI's system to the Transport Customer's point of use.

on October 31, 2020, FEI will increase its holding of SCP east to west capacity to the full amount of 105 MMcfd starting November 1, 2020. This capacity will provide more flexibility for future load growth, supply restrictions, or other marketplace constraints. Therefore, effective November 1, 2020, the cost of the 105 MMcfd of SCP east to west capacity contracted by FEI within its midstream portfolio needs to be charged to the Midstream.

In addition to increasing it's holding of SCP, FEI has entered into a T-South mitigation agreement that offsets the lost revenue from NW Natural's contracted capacity on the SCP. The mitigation revenue will be accounted for in the MCRA and flow to FEI's Sales Customers.

Determining the Cost of SCP in the MCRA

As FEI will no longer have any firm transportation service agreements for SCP capacity with external counter parties, FEI reviewed the valuation of the SCP capacity to be used in the transfer of costs to the MCRA. FEI considered various approaches to the valuation including Avoided Cost, Market Based, and Cost of Service (COS) approaches. Under the Avoided Cost and Market Based approaches there is uncertainty due to market factors such as new projects increasing regional demand, future pipeline expansions, flow dynamics, future Enbridge tolls and Enbridge system reliability. Given this uncertainty and considering that FEI owns the SCP assets, FEI valued the SCP capacity based on the cost of service of the SCP pipeline. Most regulated pipelines determine tolls through a comparable process.

The cost of service, toll and Other Revenue calculations are summarized in Table 5-7 below.

Table 5-7: Calculation of Toll and Other Revenue Credit[29]

Line No.	Particulars	Unit	Amount	Reference
1	*Physical Flows*			
2	Oliver North	MMCFD	140	
3	Kingsvale South	MMCFD	105	
4	Total	MMCFD	245	Line 2 + Line 3
5				
6	**Percent Flow across SCP to MCRA**		**43%**	**Line 3 / Line 4**
7				
8	*Capacity*			
9	Contracted Capacity	MMCFD	105	
10	Contracted Capacity	MMCFY	38,325	Line 8 x 365
11	PV 40 years		613,932	40 year PV of Line 10
12				
13	*Cost of Service*			
14	PV 40 years COS	$000	494,882	40 year PV of COS
15	Percent Flow across SCP to MCRA		43%	Line 6
16	PV COS to MCRA	$000	212,799	Line 14 x Line 15
17				
18	**Toll**	**$/MMCF**	**346.617**	**Line 16 / Line 11 x 1000**
19				
20	*Other Revenue Credit*			
21	Physical Flow allocated to MCRA	MMCFD	105	Line 3
22	Days per year		365	
23	**Other Revenue Credit**	**$000**	**13,284**	**Line 18 x Line 21 x Line 22 / 1000**

As set out in Table 5-7 above, the cost of service valuation for the 105 MMcfd of SCP east to west capacity is $346.617 per MMcfd (equivalent to approximately $0.3059/GJ per day). FEI will begin debiting this amount to the MCRA and crediting it to Other Revenue effective November 1, 2020.

5.3.3 Net Other Mitigation Revenue

The Company has been seeking, and will continue to seek, opportunities to contract the west to east capacity on the SCP. The significant decrease in the 2020 Projected mitigation revenue for the SCP west to east capacity compared to the 2019 Approved amount is due to changing market conditions. The projected mitigation revenue for the SCP west to east capacity for 2020 is based on the mitigation achieved to the end of June and the amount forecast based on

[29] The Other Revenue credit can be found in Table 5-6 and is embedded in SCP Mitigation Revenues on Schedule 23 – 2021, Line 5.

current forward market price differentials. Market price differentials for summer 2020 have narrowed considerably since the previous year.

The forecast mitigation revenue for the SCP west to east capacity for 2021 is based on the current forward market price differentials for summer 2021. FEI forecasts generating net mitigation revenue in the amount of $0.769 million in 2021.

The 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. These market conditions will continue to change over time and mitigation revenues have decreased significantly since 2019. The mitigation revenue forecast is net of the cost of using FEI gas supply resources, such as the Westcoast Energy Inc. 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.

5.4 *LNG CAPACITY ASSIGNMENT*

The $18.039 million in LNG capacity assignment Other Revenue shown in Table 5-1 above represents a transfer of costs from the delivery margin to gas costs reflecting the allocation of a portion 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 the 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.[30]

5.5 *SUMMARY*

FEI has forecast the Other Revenue components for 2020 and 2021 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 SCP Mitigation Revenues Variance Account (for variances in the items discussed in Section 5.3), the Biomethane Variance Account (for variances in the items discussed in Section 5.2.5), the CNG/LNG Recoveries deferral account (for excess revenue from the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4.3), the Flow-through deferral account (for any remaining variances from forecast in Section 5.2.4.3), and all variances from forecast in Sections 5.2.4.2 and 5.4, with variances in the remaining items affecting ROE and shared with customers through the earnings sharing mechanism.

[30] 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 MRP, FEI's O&M Expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis.

In the MRP Decision and Order G-165-20, the BCUC approved a Base 2019 O&M for FEI based on the adjusted actual 2018 O&M plus incremental O&M funding in certain areas.[31] As provided in the compliance filing to the MRP Decision[32], the resulting 2019 Base O&M for FEI is $253.790 million, which, divided by the 2019 Actual Average Customer count, results in a 2019 Base O&M per customer of $246.

In 2020, the Formula O&M is $261.798 million, representing a 5.2 percent increase from the 2019 Formula O&M approved under the 2014-2019 PBR Plan and a 3.2 percent increase from the 2019 Base O&M. The increase of 5.2 percent is primarily the result of re-setting the Base O&M as part of the approved MRP as well as an increase resulting from the formula drivers. The increase of 3.2 percent from the 2019 Base O&M is entirely due to the formula drivers. For 2021, the Formula O&M is $272.547 million, representing a 4.1 percent increase from the 2020 Formula O&M, entirely due to the formula drivers.

O&M expenses forecast outside the formula for 2020 are $52.612 million, representing a 63.3 percent increase from the amount approved for 2019. The majority of this increase stems from increases in Pension & OPEB and Insurance expense, as well as from a reclassification of expense items formerly included in base (formula) O&M. O&M expenses forecast outside the formula for 2021 are $56.844 million, representing an 8.0 percent increase from the amount projected for 2020.

Overall, the increase in Gross O&M Expense from 2019 to 2020 is 11.8 percent and the increase from 2020 to 2021 is 4.8 percent.

The components of 2020 and 2021 O&M expense are shown in Table 6-1 below.

Table 6-1: 2020 and 2021 O&M Expense

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Formula O&M	248.939	247.587	261.798	272.547	Section 11, Schedule 20, Line 8
2	Forecast O&M	32.209	36.293	52.612	56.844	Section 11, Schedule 20, Line 19
3	Total Gross O&M	281.148	283.880	314.410	329.391	Line 1 + Line 2
4	Capitalized Overhead	(33.738)	(33.738)	(50.306)	(52.703)	Section 11, Schedule 20, Line 23
5	Biomethane O&M transferred to BVA	(1.322)	(1.149)	(1.807)	(1.848)	Section 11, Schedule 20, Line 22
6	Net O&M	246.088	248.993	262.297	274.840	Sum of Lines 3 through 5

[31] MRP Decision, pp. 107-115.
[32] MRP Decision Compliance Filing, p. 5.

In the sections below, FEI provides further details on its formula and forecast O&M expenses for 2020 and 2021. Additionally, in compliance with the BCUC's directive in the MRP Decision[33], FEI provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

Base O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and 75 percent of the forecast growth in average customers. As calculated in Section 2, the 2020 and 2021 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 2.290 percent in 2020 and 3.358 percent in 2021.

For 2020, the annual operating and maintenance expense under the formula is calculated as:

> 2019 Approved Base UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)]

For 2021, the annual operating and maintenance expense under the formula is calculated as:

> 2020 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)]

Table 6-2 below shows the calculation of the 2020 and 2021 Formula O&M.

Table 6-2: Calculation of 2020 and 2021 Formula O&M

Line No.	Description	Projected 2020	Forecast 2021	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	246	252	G-165-20 FEI MRP Decision
2	I-Factor	2.290%	3.358%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	252	260	
4	Average Customer Forecast - Rate Setting Purposes	1,040,410	1,047,935	Section 2, Table 2-2
5	Inflation Indexed O&M	261.798	272.547	Line 3 x Line 4

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 115), the BCUC directed FEI to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: integrity management; maintaining system infrastructure; operations, compliance and safety; cyber security; data analytics; gas control; CEPA participation; and any other significant factors or miscellaneous items.

[33] MRP Decision, 115.

The table below shows the requested information, including the new/incremental funding in each category in 2019 dollars, escalated by the annual formula factors to arrive at the Formula O&M amounts, and the forecast amounts for 2020.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending

System Operations, Integrity and Security		2020 Formula O&M[1]	Forecast 2020 O&M	2020 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
		$ millions			
Integrity Management	$ 1.350	$ 1.381	$ 1.381	$ -	$ -
Maintaining System Infrastructure	$ 0.700	$ 0.716	$ 0.716	$ -	$ -
Operations, Compliance and Safety	$ 0.600	$ 0.614	$ 0.614	$ -	$ -
Cyber Security	$ 0.508	$ 0.520	$ 0.520	$ -	$ -
Data Analytics	$ 0.300	$ 0.307	$ 0.307	$ -	$ -
Gas Control	$ 0.650	$ 0.665	$ 0.665	$ -	$ -
CEPA Participation	$ 0.700	$ 0.716	$ 0.716	$ -	$ -
Other	$ -	$ -	$ -	$ -	$ -
Total	$ 4.808	$ 4.918	$ 4.918	$ -	$ -

Notes:
(1) 2020 Formula O&M is the incremental funding with Net Inflation factor applied (2.290%)
(2) Cumulative Forecast/Actual variance is the same as the 2020 (first year of MRP) Forecast/Actual variance.

At the time of preparing this Application, FEI has critical initiatives underway and is in the process of finalizing its plans to implement further activities. As shown in the table above, FEI is forecasting to spend all of the incremental funding approved. For 2020, given that the MRP Decision was issued part way through the year, there will likely be a variance between the actual expenditures in 2020 and the amounts calculated using the formula escalators. Over the term of the MRP, FEI anticipates that the total new/incremental spending in the combined categories of System Operations, Integrity and Security required will be relatively close to the cumulative approved formula amounts, although there will continue to be variations from year to year.

In the MRP Decision, the BCUC also directed FEI to describe how it is prioritizing its new/incremental funding approved for System Operations, Integrity and Security.

The categories of the new/incremental System Operations, Integrity and Security funding, as shown in Table 6-3 above, were developed based on the anticipated requirements over the term of the MRP, recognizing that priorities may change and that the expenditures may vary from year to year depending upon factors such as the availability of resources (i.e., labour vacancies) and the timing of activities. The common theme underlying the need for the new/incremental funding is to support the safe and reliable delivery of energy to customers. In prioritizing the new/incremental funding, FEI will consider factors such as regulation changes, code requirements, safety and security requirements, and customer requirements which may create a higher priority and urgency for certain expenditures compared to other expenditures. Similar to what other organizations may do, funds are reprioritized as required depending on the business environment, conditions, and requirements the Company is facing. In prioritizing new/incremental spending, the safety and reliability of the system will be paramount.

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, O&M supporting Biomethane, NGT O&M, LNG production O&M, integrity digs and BCUC fees, as well as any exogenous factors. These amounts are shown in Table 6-4 below along with a comparison to 2019.

Table 6-4: 2020 and 2021 Forecast O&M ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Pension/OPEB (O&M Portion)	13.795	13.795	21.147	22.354
2	Insurance	5.473	6.294	8.521	9.908
3	Integrity Digs	-	-	4.400	4.800
4	BCUC Levies	-	-	6.782	7.290
5	**Clean Growth Initiatives:**				
6	Biomethane O&M	1.369	1.205	1.807	1.848
7	Renewable Gas Development	-	-	0.400	0.750
8	NGT O&M	2.339	2.060	1.694	1.813
9	LNG				
10	RS46 O&M (prior to 2020)	7.432	10.846	-	-
11	Production O&M (2020 to 2024)	-	-	7.861	8.081
12	**Exogenous Factors:**				
13	EHT & MSP	1.801	2.093	-	-
14	Forecast O&M	32.209	36.293	52.612	56.844

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by the BCUC in 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 digs, 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 for 2020 is based upon actuarial estimates using a range of assumptions as at December 31, 2019 provided by the Company's external third party actuary, Willis Towers Watson. The pension and OPEB expense for 2021 is similarly based on actuarial assumptions determined at December 31, 2019 but has been further updated to reflect the volatility in the assumptions around expected return on assets and discount rates that has occurred during the first half of 2020, in part due to the COVID-19 pandemic. In addition to

O&M, pension and OPEB expense is embedded in Capital Expenditures, Asset Removal Costs, and Core Market Administration Expense (CMAE) categories, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	O&M	13.795	13.795	21.147	22.354
2	Capital - Growth	0.903	0.903	1.519	1.832
3	Capital - Other (Approved)	2.661	2.661	3.275	3.317
4	Capital - Other (to Pension & OPEB Variance Deferral) [1]	-	-	1.198	2.079
5	Deferral - Asset Removal Costs	1.050	1.050	1.764	2.128
6	Deferral - CMAE	0.317	0.317	0.534	0.644
7	Total	18.727	18.727	29.437	32.354

Notes:

1 this line item represents the pension and OPEB expense difference between the estimates embedded in the Sustainment & Other Capital forecasts on Line 3 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019, and the actuarial estimates updated for 2020 and 2021 rate setting purposes.

2019 Actual pension and OPEB expense equals the 2019 Approved expense as any variances from the approved amount for setting 2019 rates are flowed through to the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-138-14[34].

Projected 2020 pension and OPEB expense has increased by $10.710 million compared to the 2019 Approved expense primarily due to the following factors:

- An approximately $10.3 million increase in amortization of actuarial losses and increases in current service costs and interest costs due to a decline in discount rates. The discount rates, which are determined with reference to the market rate of interest on high quality debt instruments at a point in time, decreased from 3.5 percent, which was used to determine 2019 Approved expense, to 3.0 percent, which is used to determine 2020 Projected expense; and
- An approximately $1 million increase due to an increase in expected interest provision where a portion of investment returns are allocated to provide for indexing of pension benefits;

offset in part by:

- An approximate $0.6 million decrease due to the full elimination of the Medical Services Premium (MSP) in 2020 as compared to 50 percent MSP in place for 2019.

[34] Total pension and OPEB expense for 2019 was $15.082 million; therefore a credit of $3.645 million was recorded in the deferral account in 2019.

The 2021 pension and OPEB expense is forecasted to be $2.917 million higher than the 2020 Projected expense primarily due to two factors. First, there is a forecasted further decline in discount rates in mid-2020 due to the volatility in capital debt markets. Second, while there has been a recovery in the value of pension plan assets since the beginning of the pandemic in 2020, it is still expected that the estimated annual asset return for 2020 will remain lower than expected and this expectation has been incorporated into the determination of the 2021 pension and OPEB expense.

With respect to the discount rates used in determining pension expense, FEI notes that, due to the timing of filing this Application, the rates have been impacted by the financial market impacts of COVID-19. FEI will monitor the rates for the remainder of the year, and file an Evidentiary Update to reflect any significant changes.

6.3.2 Insurance Expense

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

Table 6-6: Insurance Expense ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Insurance Premiums	5.473	6.294	8.521	9.908	Section 11, Schedule 20, Line 12
2	Total	5.473	6.294	8.521	9.908	

The projected insurance premium expense for 2020 of $8.521 million incorporates FEI's July 2020 insurance renewals, an increase of $3.048 million from what was approved for 2019. The higher premiums experienced in 2020 are expected to continue into 2021. The forecast for 2021 insurance is $9.908 million, an increase of $1.387 million from 2020. The forecast for 2021 is calculated as the amount of the first six months of the known annual insurance premium for July 2020 to June 2021 of $9.666 million and applying a 5 percent increase for the remaining six months[35]. FEI has experienced significant increases in insurance expense in the last two renewals as a result of various insurers reducing their capacity and increasing restrictions and retentions.

[35] $9.666 million/2 = $4.833 million x 1.05 = $5.075 million. $4.833 million + $5.075 million = $9.908 million.

6.3.3 Integrity Digs

In the MRP Decision and Order G-165-20[36], the BCUC approved FEI's proposal to change the treatment of integrity digs from that approved in the 2014-2019 PBR Plan. As a result, the costs of integrity digs are now treated as a flow-through item and variances between forecast and actual amounts will be captured in the Flow-through deferral account. In accordance with the approved deferral account treatment of integrity digs, FEI provides the following update and forecast of its integrity dig expenditures. Costs associated with integrity digs are primarily outside of FEI's control, and there can be considerable uncertainty related to scope, cost, timing and volume of expected digs.

The following table provides the forecast, and builds on information that was provided to the BCUC as part of the response to BCUC IR1 32.6 in the MRP proceeding. FEI has broadened the Reason for Dig categories in the table below to be more general than previously reported, thereby improving their relevance to future reports. Footnotes to the table identify how these numbers can be compared to past submissions. FEI considers the Reason for Dig categories to be the significant drivers for uncertainty with respect to integrity digs. Discussion of each category follows.

Table 6-7: Integrity Digs Activities and Expenditures

		Number of Digs per Year		
Line No.	**Reason for Digs**	**2019**	**2020 Projection**	**2021 Forecast**
1	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[1]	11	60	80
2	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[2]	45	50	40
3	Ongoing ILI digs not covered by a category above[3]	37	10	25
4	Non-ILI digs identified through above-ground cathodic protection and coating surveys	24	25	10
5	**Total Integrity Digs**	**117**	**145**	**155**
6	Total Expenditures ($000s)	$3,100	$4,400	$4,800
7	Cost per dig ($000s)	$26	$30	$31

Notes:

1 Previously reported as "Circumferential magnetic flux leakage in-line inspection digs", which is just one example of integrity digs due to a first-time inspection with an ILI technology or ILI tool in a given pipeline segment.

2 Previously reported as "Dent digs (includes dig selections that were influenced by the strain-based criteria)". The intent of this Reason for Dig was to capture increasing numbers of integrity digs due to a change to an industry practice or industry standard. The current wording will facilitate FEI's future reporting of other potential changes to industry practices and standards that will require a corresponding change from FEI's past integrity dig practices.

36 MRP Decision, p. 74.

[3] Previously reported as "Other ILI digs". These are digs resulting from FEI's routine and ongoing use of previously adopted ILI technology or ILI tools.

FEI's forecasts related to In-line Inspection (ILI) technology/tools not previously run in a given pipeline are influenced by the following:

- One EMAT tool run was completed in 2019, with subsequent digs estimated within FEI's forecasts for 2020 and 2021. A second EMAT inspection is expected to be completed in 2020, with subsequent integrity digs estimated within FEI's forecast developed for 2021. FEI is currently planning the Transmission Integrity Management Capabilities (TIMC) project to mitigate the risk of rupture failure due to Stress Corrosion Cracking (SCC) and other crack-like imperfections. Where practical, this will be achieved through alteration of the transmission system to allow for passage of the EMAT ILI tools and the collection of data;
- FEI continues to run Circumferential MFL (Magnetic Flux Leakage) tools in its transmission pipelines, and by the end of 2020 will have run these tools in all pipelines constructed in the 1970s or earlier. Baseline inspections with this technology in FEI's later-constructed pipelines are expected to be completed over the next 15 years; and
- In 2020, FEI was granted a CPCN for its Inland Gas Upgrade project. Future forecasts will include FEI's estimates of integrity digs resulting from this project, once lines become available for their first-time in-line inspection.

FEI's forecasts related to evolving industry practices/standards continue to be influenced by the required adoption of the strain-based criteria for dents in current industry practice and standards.

FEI's forecasts related to ongoing ILI integrity digs result from FEI's analysis of its MFL and geometry tool runs, which are scheduled on a maximum seven-year interval and will vary from year to year. As other tool technologies (e.g. CMFL, EMAT) become established on a similar re-run schedule, it is expected that FEI's estimates of ongoing ILI digs will also include integrity digs identified through those tools.

FEI has continued to experience a range of scope and costs associated with its 2019 integrity digs and 2020 year-to-date integrity digs. Cost drivers include site access, site management during the dig, site restoration, and whether or not a repair is deemed to be required based on in-ditch pipeline examination during the dig.

6.3.4 BCUC Levies

FEI's forecast for BCUC levies for 2020 and 2021 is based on two components: (i) the BCUC levy; and (ii) FEI's portion of funding for the BCUC hearing room facilities.[37]

The 2020 Projected BCUC levies for FEI is $6.782 million and includes the following:

- The projected BCUC levy of $6.635 million. This amount is comprised of the levy amount from Order G-138-19A1 for the BCUC's Fiscal 2019/20 year which is applied to FEI's first fiscal quarter of 2020 (January to March),38 and the levy amount from Order G-134-20 for the BCUC's Fiscal 2020/21 year which is applied to FEI's remaining three quarters of 2020 (April to December); and
- An estimate of $0.147 million for FEI's portion of the funding for the BCUC hearing room facilities.

The 2021 Forecast BCUC levies for FEI is $7.290 million and includes the following:

- The forecast BCUC levy of $7.143 million based on Order G-134-20 for the BCUC's Fiscal 2020/21 year because this is the best information available at this time. FEI notes that the BCUC levy calculation for Fiscal 2021/22 will not be available until early in 2021; and
- An estimate of $0.147 million for FEI's portion of the funding for the BCUC hearing room facilities.

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.

6.3.5 Clean Growth Initiative - Biomethane O&M

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

---

[37] Located at 12th floor, 1125 Howe Street, Vancouver, BC and managed/operated by Allwest Reporting Ltd.
[38] Which is the BCUC's Fiscal 2019/20 fourth quarter.

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

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Program Overhead	0.986	0.470	1.058	1.079
2	City of Surrey	0.010	0.010	0.010	0.010
3	Kelowna Upgrader	0.147	0.403	0.492	0.502
4	Salmon Arm Upgrader	0.180	0.276	0.194	0.194
5					
6	Fraser Valley Biogas	0.011	0.011	0.010	0.010
7	Salmon Arm Landfill	0.011	0.011	0.010	0.010
8	Kelowna Landfill	0.011	0.011	0.010	0.010
9	Seabreeze Farms	0.011	0.011	0.010	0.010
10	Lulu Island WWTP	0.001	0.001	0.003	0.010
11	Dickland Farms	-	-	0.010	0.010
12	Total Biomethane O&M	1.369	1.205	1.807	1.848

[1] Prior to order G-165-20 lines 1-4 were transferred to the BVA and lines 6-11 remained in delivery rates. Order G-165-20 approves the legacy interconnection charges to be accounted in the BVA, this results in the total Biomethane O&M (line 12) being transferred to the BVA.

The 2020 Projected and 2021 Forecast total Biomethane O&M is $1.807 million and $1.848 million, respectively.

The 2020 Projected Biomethane O&M of $1.807 million is $0.438 million higher than the 2019 Approved O&M of $1.369 million. This is primarily due to increased run time and maintenance costs of the Kelowna upgrader.

The 2021 Forecast Biomethane O&M of $1.848 million is in line with the 2020 Projected amount with the increase due to inflation.

6.3.6 Clean Growth Initiative – Renewable Gas Development

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

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Renewable Gas Development	-	-	0.400	0.750	Section 11, Schedule 20, Line 17
2	Total	-	-	0.400	0.750	

In order to support the continued growth of the renewable gas portfolio, including investigating the feasibility of other renewable gases such as hydrogen and synthetic methane, FEI requires additional resources within its Renewable Gas team to support work on safety, codes and standards, and feasibility work more generally. The O&M requirements for this initial phase of hydrogen development are approximately $0.400 million in 2020, increasing to approximately $0.750 million in 2021 to hire or contract resources to proceed with work on safety, codes and standards, and feasibility work.

6.3.7 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 and FEI-owned LNG tankers available for rental to LNG customers. Table 6-10 below summarizes the NGT O&M.

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

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	CNG Stations	0.929	0.778	0.791	0.856
2	LNG Stations	0.540	0.741	0.303	0.311
3	LNG Tankers	0.770	0.495	0.500	0.545
4	Emergency Response and Preparedness (ERAP)	0.100	0.046	0.100	0.100
5	**Total NGT O&M**	**2.339**	**2.060**	**1.694**	**1.813**

The 2020 Projected O&M expense is approximately $0.645 million less than the 2019 Approved O&M. This is primarily due to the closure of three LNG stations and the anticipated completion of two transit CNG facilities in 2019 which did not occur as the two organizations did not proceed with FEI.

The NGT O&M for 2021 is forecast to increase by approximately $0.119 million from the 2020 Projected level. This is primarily due to the incremental increase of CNG and LNG demand from 2020 Projected to 2021 Forecast as discussed in Section 3.3.4 of this Application.

6.3.8 Clean Growth Initiative - Variable LNG Production Costs

For the MRP, 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 fixed costs to operate the LNG plant, regardless of its use (for peak shaving storage, or LNG production for sales). The remaining portion of total LNG O&M costs is treated as flow-through outside of formula O&M. These costs represent the variable costs for the production of LNG (liquefaction of natural gas, the dispensing of LNG, the handling and loading of tankers with LNG, etc.) where the costs fluctuate and are dependent on sales volumes.

A table breaking out the various components of the Variable LNG Production Costs is included below.

Table 6-11: Variable LNG Production O&M ($ millions)[39]

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Tilbury Plant:				
2	Labour	n/a	n/a	1.375	1.650
3	Materials	n/a	n/a	1.000	0.540
4	Contractor	n/a	n/a	1.365	1.131
5	Power	n/a	n/a	3.200	3.813
7	Fees and Employee Expenses	n/a	n/a	0.300	0.308
8	Sub-total	n/a	n/a	7.240	7.443
9	Mt. Hayes Plant				
10	Labour	n/a	n/a	0.306	0.315
11	Materials	n/a	n/a	0.025	0.026
12	Contractor	n/a	n/a	0.054	0.056
13	Power	n/a	n/a	0.236	0.243
14	Fees and Employee Expenses	n/a	n/a	0.000	0.000
16	Sub-total	n/a	n/a	0.621	0.639
17	Forecast O&M	na	n/a	7.861	8.081

The Variable LNG Production O&M expense required for operation of the Expanded Tilbury LNG facility[40] and the Mt Hayes LNG facility consists of variable labour, materials, certain contractor costs, power to run the plants, and employee expenses for the employees included in variable labour, as set out in the MRP Application in Section 2.4.2.2.3 Flow Through Treatment, page C-25. The definition of variable costs was also outlined in the response to BCUC IR2 173.4 as part of the MRP proceeding.

These amounts are projected to be $7.861 million in 2020 and $8.081 million in 2021.

Included in the variable labour is the labour for LNG operators for truck loading and shunting of LNG, Millwrights and Electrical and Instrumentation Technicians to support production-related maintenance activities, and Operations Management personnel to oversee activities. Labour costs are expected to increase in 2021, reflecting the full complement of staffing and labour required.

The materials costs are for materials related to production and for freight for the shipping of LNG. In 2021, materials costs are expected to decrease as shunting activities (movement of LNG containers to facilitate loading) will be transitioned to internal labour.

The variable contractor services include services used for truck loading and sewer water treatment related to the production of LNG.

[39] 2019 Actuals and Approved not available as 2020 is the first year under the MRP where the variable portion of LNG O&M costs are forecasted with the forecast variances treated as flow-through.

[40] The expanded LNG facility is 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.

In 2020, contractor services are included for work performed by Partners in Performance (PiP) and Global IO. PiP completed a review of FEI's LNG operation and tanker loading to help identify opportunities for improvements, specifically around NGT and ISO container loading. Through this review, FEI alleviated constraints in the loading process and identified Key Performance Indicators (KPIs). Global IO was contracted to review FEI's LNG business to propose a shift schedule, which will help meet business objectives, local labour availability, recruitment and retention considerations, and operational productivity. In 2021, based on recent experience, a similar but slightly lower amount for contractor services is forecast.

Other variable costs include those for power (i.e., electricity) costs, employee expenses and shunting truck costs. Electricity costs vary directly with production and are estimated based on the forecast sales volumes for 2021, which are forecast to be higher than 2020 sales projections.

The overall 2021 Forecast Variable LNG Production O&M costs are estimated to be similar to the 2020 Projected Amount, with increases consistent with general inflation.

6.4 *NET O&M EXPENSE*

Net O&M expense is Gross O&M less capitalized overhead and Biomethane O&M transferred to the BVA. As approved by the BCUC in Order G-165-20, the capitalized overhead rate is set at 16 percent for FEI. After capitalized overhead and the transfer of $1.807 million of Biomethane O&M to the BVA, the net O&M expense for 2020 is $262.297 million. For 2021, after capitalized overhead and the transfer of $1.848 million of Biomethane O&M to the BVA, the net O&M expense is $274.840 million.

6.5 *SUMMARY*

Overall, the increase in Gross O&M Expense from 2019 Approved to 2020 Projected is 11.8 percent. The formula-driven O&M is increasing at a rate of 5.2 percent with the O&M forecast outside of the formula increasing at a rate of 63.3 percent. The capitalized overhead rate has increased from 12 percent to 16 percent in 2020, as approved by the BCUC in Order G-165-20.

For 2021, Gross O&M Expense is forecast to increase by 4.8 percent from 2020 Projected. The formula-driven O&M is increasing at a rate of 4.1 percent with the O&M forecast outside of the formula increasing at a rate of 8.0 percent. The capitalized overhead rate remains unchanged from 2020.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

Rate Base for FEI is forecast to be $5.047 billion for 2020 and $5.213 billion for 2021. 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, deferred income tax, and LILO benefit.

FEI's 2020 Rate Base includes the full-year impacts of the 2019 closing plant balances as well as the impact of the following amounts:

- Mid-year impact of capital additions, net of Contributions in Aid of Construction (CIAC) additions, resulting from regular capital expenditures of $285.204 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $183.428 million;
- Full-year impact of $304.415 million for the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project as discussed in Section 7.2.3.1 below;
- Impact of $23.481 million for the Tilbury Expansion Project as discussed in Section 7.2.3.1 below;
- Full-year impact of the 2019 capital formula dead band adjustment of $61.082 million as shown in Row 35, Column 8 in Table 14-3 in Section 14.4.1; and
- Full-year impact of the 2014-2019 cumulative capital expenditures within the dead band of $65.006 million as shown in Row 38, Column 2 in Table 14-3 in Section 14.4.1.

FEI's 2021 Rate Base includes the full-year impacts of the 2020 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of capital additions, net of CIAC additions, resulting from regular capital expenditures of $287.834 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $193.499 million;
- Full-year impact of $28.630 million of 2020 expenditures and related AFUDC for the LMIPSU Project as discussed in Section 7.2.3.1 below;
- Impact of $4.147 million for the Tilbury Expansion Project as discussed in Section 7.2.3.1 below; and
- Full-year impact of $45.846 million 2020 expenditures and related AFUDC for the Inland Gas Upgrade (IGU) Project as discussed in Section 7.2.3.1 below.

In addition, various changes in deferred charges, working capital and other items increase Rate Base by a net amount of $56.231 million in 2020 and decrease Rate Base by a net amount of $15.671 million in 2021.

Details of the 2020 and 2021 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-165-20, FEI received the following approvals for capital expenditures:

- Approval of FEI's forecasts submitted for regular sustainment and other capital expenditures for the years 2020 through 2023;
- Approval of growth capital to be set annually on a formula basis; and
- Approval of a number of items to be forecast outside the formula on an annual basis.

The components of 2020 and 2021 regular capital expenditures are shown in Table 7-1 below.

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

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Formula Growth Capex	40.143	88.454	68.199	62.657	Table 7-2, Line 5
2	Formulaic CIAC			2.452	2.253	Section 11, Schedule 9, Line 2
3	Formula/Forecast Sustainment & Other Capex	122.928	151.476	161.300	162.860	Section 11, Schedule 4, Lines 15 + 16
4	Flow through Capex	25.210	8.080	10.398	27.012	Section 11, Schedule 4, Sum of Lines 11 through 14
5	Total Gross Regular Capex	188.281	248.010	242.349	254.782	Sum of Lines 1 through 4
6	Less: Formula CIAC	(5.812)	(5.700)	(2.452)	(2.253)	- Line 2
7	Less: Forecast CIAC	-	-	(4.767)	(3.752)	Section 11, Schedule 9, - Line 6/1000 - Line 6
8	Net Regular Capex	182.469	242.310	235.130	248.777	Sum of Lines 5 through 7

In the subsections below, FEI provides further details on its regular capital expenditures for 2020 and 2021.

7.2.1 Formula Growth Capital Expenditures

The formula-driven growth capital expenditures start from a base of the prior year's approved unit cost for growth capital (UCGC), which is escalated by the prior year's inflation and multiplied by the forecast gross customer additions for the current year. As calculated in Section 2, the 2020 and 2021 net inflation factors based on prior year's BC-CPI and BC-AWE are 2.290 percent and 3.358 percent, respectively. Forecast gross customer additions in 2020 of 18,000 and in 2021 of 16,000 are then multiplied by the unit cost for growth capital.

For 2020, the annual growth capital expenditures under the formula is calculated as:

2019 Approved Base UCGC x [1 + (I Factor – X Factor)] x Gross Customer Additions

For 2021, the annual growth capital expenditures under the formula is calculated as:

2020 Approved formula UCGC x [1 + (I Factor – X Factor)] x Gross Customer Additions

Table 7-2 below shows the calculation of the resulting 2020 and 2021 Formula growth capital expenditures.

Table 7-2: Calculation of 2020 and 2021 Formula Growth Capital ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Prior Year Base Unit Cost Growth Capital ($/customer)			3,704	3,789	G-165-20 and Section 11, Schedule 4, Line 2
2	Net Inflation Factor			2.290%	3.358%	Section 11, Schedule 3, Line 9
3	Current Year Unit Cost Growth Capital ($/customer)			3,789	3,916	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast			18,000	16,000	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	40.143	88.454	68.199	62.657	Line 3 x Line 4 / 1,000,000
6	Formulaic CIAC			2.452	2.253	Section 11, Schedule 9, Line 2
7	Total Growth CapEx			70.651	64.910	Line 5 + Line 6

The 2020 and 2021 Formula Growth Capital amounts of $68.199 million and $62.657 million, respectively, are net of CIAC; therefore, CIAC must be added to the calculated growth capital amounts to determine total growth capital before CIAC. The 2020 and 2021 CIAC amounts included in the calculated growth capital are $2.452 million and $2.253 million, respectively.

7.2.2 Forecast Capital Expenditures

The level of forecast capital expenditures approved for 2020 and 2021 by the MRP Decision and Order G-165-20 is shown in Table 7-3 below.

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

Line No.	Description	Approved 2019	Actual 2019	Approved 2020	Approved 2021	Reference
1	Sustainment Capital	89.044	107.278	111.530	112.944	Section 11, Schedule 4, Line 15
2	Other Capital	33.884	44.198	49.770	49.916	Section 11, Schedule 4, Line 16
3	Total	122.928	151.476	161.300	162.860	Line 1 + Line 2

7.2.3 Flow-Through Capital Expenditures

FEI is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to clean growth initiatives, or because of the uncertainty in scope, costs and timing. The amounts for 2020 and 2021 are shown in Table 7-4 below along with a comparison to 2019.

Table 7-4: Flow-Through Regular Capital Expenditures ($ millions)[41]

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Pension/OPEB (Growth Capital Portion)	0.903	0.903	1.519	1.832	Section 11, Schedule 4, Line 11
2	Biomethane Upgraders	11.300	0.618	2.890	15.690	Section 11, Schedule 4, Line 12
3	Biomethane Interconnect	1.561	(0.138)	1.910	4.460	Section 11, Schedule 4, Line 13
4	NGT Assets	8.455	3.654	4.079	5.030	Section 11, Schedule 4, Line 14
5	Forecast Regular Capex	22.219	5.037	10.398	27.012	Sum of Lines 1 through 4

Each of these items is described further below.

Pension/OPEB (Growth Capital Portion)

The 2020 Projected and 2021 Forecast Pension and OPEB capital expenditures of $1.519 million and $1.832 million, respectively, represent the forecast growth capital portion of the total Pension and OPEB costs for 2020 and 2021. Pension and OPEB costs are described in Section 6.3.1.

Biomethane Upgraders and Interconnect

The 2019 Actual amounts were less than expected due to the timing of construction of biomethane projects. In the Biomethane Upgrader category, the majority of the original approved amount was allocated to the City of Vancouver Biomethane project, which has been delayed based on the approval date of September 2019 and slower than expected initial spending. It is expected that the full amount will be moved into future years. The interconnect portion of capital is set aside for FEI costs related to new supply not owned by FEI. These costs were not incurred due to delays in supplier execution of their projects.

The following table provides additional detail by project for the 2020 and 2021 Biomethane upgrader and interconnect capital projection and forecast, including the Order approving the project.

[41] For consistent presentation, the table excludes PBR amounts that are not comparable to the MRP amounts.

Table 7-5: Biomethane CapEx

Line No.	Description	Order	Projected 2020	Forecast 2021
1	City of Vancouver	G-235-19	2.070	15.570
2	Kelowna Upgrader	E-19-12	0.700	0.120
3	Salmon Arm Upgrader	G-194-10	0.120	-
4	Total Biomethane Upgraders		2.890	15.690
5				
6	Lulu Island WWTP	E-13-13	1.380	0.020
7	Dickland Farms	E-13-20	0.100	1.230
8	City of Vancouver	G-235-19	0.230	1.730
9	Ren Energy	G-60-20	0.100	1.480
10	Seabreeze Farms	E-11-19	0.100	-
11	Total Biomethane Interconnect		1.910	4.460
12				
13	Total Biomethane Upgraders & Interconnect		4.800	20.150

The Projected 2020 capital expenditures for Biomethane upgraders are $2.890 million and the 2021 Forecast is $15.690 million. The Kelowna and Salmon Arm upgrader capital will be transferred to plant in service when spent. The City of Vancouver capital is expected to be transferred to plant in service in 2022 at project completion.

The 2020 Projected Biomethane Interconnect capital expenditures are $1.910 million and the 2021 Forecast amounts are $4.460 million. The Seabreeze capital will be transferred to plant in service in 2020, Lulu Island and Dickland Farms will transferred to plant in service in 2021, and City of Vancouver and Ren Energy will be transferred to plant in service in 2022.

Natural Gas for Transportation (NGT) Assets

The following table provides additional detail by project for the 2020 and 2021 NGT Assets capital expenditures.

Table 7-6: NGT Assets Capital Expenditures[42]

Line No.	Description	BCUC Order	Projected 2020	Forecast 2021
1	E360S (CNG)	G-237-19	(0.036)	-
2	Fresh Direct (CNG)	G-238-19	0.110	-
3	London Drug (CNG)	G-299-19	0.195	-
4	Waste Connections Expansion (CNG)	G-110-20	0.180	-
5	Waste Management Expansion (CNG)	G-77-20	0.264	-
6	Annacis Island (CNG)	To be filed	1.895	-
7	Cumberland (CNG)	To be filed	0.950	0.950
8	Waste Connections Abbotsford (CNG)	To be filed	0.721	0.080
9	Prince George (CNG)	To be filed	-	1.000
10	District of Cowichan (CNG)	To be filed	-	1.000
11	LNG Tanker (LNG)	GGRR	(0.201)	2.000
12	**Total NGT Capital Expenditures**		**4.079**	**5.030**

The 2020 Projected and 2021 Forecast NGT Assets capital expenditures are $4.079 million and $5.030 million, respectively. For 2020, the capital expenditures are associated with: (i) the construction of six new stations (Environmental 360, Fresh Direct, London Drugs, Annacis Island, Cumberland, and Waste Connection Abbotsford), forecasted to be approximately $3.836 million; and (ii) the expansion of two existing stations (Waste Connection Expansion and Waste Management Expansion), forecasted to be approximately $0.444 million. Further, a PST refund of $0.201 million will be collected in 2020 for the first three marine tankers put into FEI's LNG logistics fleet. For 2021, the capital expenditures are associated with completing the Cumberland and the Waste Connections Abbotsford CNG stations and construction of two new CNG stations (Prince George and District of Cowichan) totalling to approximately $3.030 million, and one additional marine LNG tanker forecasted to be approximately $2.000 million.

7.2.3.1 CPCN and Special Project Capital Expenditures

Also forecast outside of the formula are any capital expenditures related to approved CPCNs, and other projects that are proceeding as a result of an Order in Council (OIC). In 2020, FEI is forecasting capital expenditures related to the Tilbury Expansion Project, the LMIPSU Project, and the Inland Gas Upgrade (IGU) Project. The Tilbury Expansion Project was included in rate base on January 1, 2019, while clean-up and close-out costs will continue be incurred in 2020 and 2021. The Coquitlam and Burnaby sections of the LMIPSU Project and Coquitlam station portions of the LMIPSU Project were completed in 2019, and are included in rate base in 2020. A portion of the IGU Project (Mackenzie, Cranbrook, and Fording Laterals) is forecast to be completed in 2020, and is included in rate base in 2021. Each project is discussed below.

42 LNG Tanker capital expenditures are approved by BC GGRR Prescribed Undertaking 2.

TILBURY EXPANSION PROJECT

The cost recovery of expenditures associated with the Tilbury Expansion Project is authorized by Direction No. 5 to the BCUC as amended by OIC Nos. 557 (2013), 749 (2014), and 162 (2017). Under Direction No. 5, FEI can spend up to $425 million, plus AFUDC and feasibility and development costs, to construct storage and liquefaction facilities. FEI is forecasting the cost of the Tilbury Expansion Project to be within the authorized amount, at a total of $495 million as outlined in the table below ($425 million excluding AFUDC and feasibility and development costs). $467.3 million of the Tilbury Expansion Project was added to rate base as of January 1, 2019. The remaining expenditures of $14.7 million prior to 2020[43], and 2020 expenditures of $8.062 million[44] (excluding AFUDC), will be added to rate base in 2020, with the final $4.147 million[45] of 2021 expenditures added to rate base in the same year.

Table 7-7: Tilbury Expansion Project ($ millions)

Description	Prior Years	2020	2021	Total
Capital Expenditures	$ 412.783	$ 8.062	$ 4.147	$ 424.992
Feasability & Development	$ 6.494			$ 6.494
AFUDC	$ 62.715	$ 0.684		$ 63.399
Total	**$ 481.992**	**$ 8.746**	**$ 4.147**	**$ 494.885**

LMIPSU PROJECT CPCN

The LMIPSU Project CPCN application was filed with the BCUC in December 2014 and approved through Order C-11-15. The LMIPSU Project includes work on the Coquitlam Gate IP project, which addresses an increasing number of gas leaks on the Coquitlam Gate IP line and restores operational flexibility and resiliency to the Metro Vancouver IP system, and the Fraser Gate IP project, which will provide required seismic upgrades to the Fraser Gate IP line. The Burnaby and Coquitlam IP sections of the Coquitlam Gate IP project and the Coquitlam gate station were placed in service in 2019 at a cost of $304.415 million and were added to rate base January 1, 2020. FEI forecasts expenditures of $28.630 million[46] and $16.170 million[47] (excluding AFUDC) in 2020 and 2021, respectively, to complete the Coquitlam Gate and Fraser Gate portions of the LMIPSU Project. Any remaining capital expenditures are primarily related to close-out and clean-up costs and will be added to rate base in future years (beyond 2020 or 2021). The total estimated capital cost for the LMIPSU Project, including AFUDC and abandonment/demolition costs, is $449.065 million.

IGU PROJECT CPCN

The IGU Project CPCN application was filed with the BCUC in December 2018 and approved through Order G-12-20. The IGU Project includes upgrades to 29 pipeline laterals in the Interior

[43] $482 million per Table 7-7 less $467.3 million = $14.7 million.
[44] Section 11 – 2020, Schedule 5, Line 9, Column 2.
[45] Section 11 – 2021, Schedule 5, Line 9, Column 2.
[46] Section 11 – 2020, Schedule 5, Line 7, Column 2.
[47] Section 11 – 2021, Schedule 5, Line 7, Column 2.

of British Columbia that currently do not accommodate In-line Inspection. This project will address a pipeline integrity risk associated with pipelines that operate at a hoop stress that has the potential for pipeline rupture due to corrosion on these lines that cannot be detected using current pipeline integrity methods. The Mackenzie, Cranbrook, and Fording Laterals are being upgraded in 2020 at an expected projected cost of $18.541 million, $14.260 million, and $13.045 million, respectively, totaling $45.846 million. These expenditures will be added to rate base January 1, 2021. The estimated capital cost for the IGU Project, including AFUDC and abandonment/demolition costs, is approximately $360 million. FEI forecasts expenditures of $45.846 million[48] and $60.630 million[49] (excluding AFUDC) in 2020 and 2021, respectively. The remaining IGU capital expenditures are forecasted to be added to rate base in future years, and are therefore not included in 2020 or 2021 delivery rates.

7.3 *2020 AND 2021 PLANT ADDITIONS*

The 2020 and 2021 Plant Additions are comprised of: (i) FEI's 2020 and 2021 regular capital expenditures from Section 7.2 above, plus the Tilbury Expansion Project, LMIPSU Project and the IGU Project; (ii) the change in work in progress which adjusts for capital expenditures for projects such as those listed in Section 7.2 that are in progress at year end; (iii) AFUDC; and (iv) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-8: Reconciliation of 2020 and 2021 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	Projected 2020	Forecast 2021	Reference
1	Formula Growth Capex	70.651	64.910	Section 11, Schedule 4, Line 8
2	Forecast Sustainment & Other Capex	161.300	162.860	Section 11, Schedule 4, Lines 15 + 16
3	Flow through Capex	10.398	27.012	Section 11, Schedule 4, Sum of Lines 11 through 14
4	Total Gross Regular Capex	242.349	254.782	Sum of Lines 1 through 3
5	Capitalized Overheads	50.306	52.703	Section 11, Schedule 5, Line 18
6	AFUDC	3.648	3.654	Section 11, Schedule 5, Line 19
7	Change in Work in Progress	(3.880)	(17.300)	Section 11, Schedule 5, Line 21
8	Total Regular Additions to Plant	**292.423**	**293.839**	
9				
10	Special Projects and CPCN Capex			
11	LMIPSU	28.630	16.170	Section 11, Schedule 5, Line 7
12	IGU	45.846	60.630	Section 11, Schedule 5, Line 8
13	Tilbury Expansion Project	8.062	4.147	Section 11, Schedule 5, Line 9
14	Special Projects and CPCN AFUDC	2.930	2.301	Section 11, Schedule 5, Line 25
15	Change in Special Projects and CPCN Work in Progress	242.427	(2.380)	Section 11, Schedule 5, Line 27
16	Total Special Projects and CPCN Additions to Plant	**327.895**	**80.868**	
17				
18	Total Plant Additions	**620.318**	**374.707**	

48 Section 11 – 2020, Schedule 5, Line 8, Column 2.

49 Section 11 – 2021, Schedule 5, Line 8, Column 2.

7.4 ACCUMULATED DEPRECIATION

The rate base of FEI 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 2020 and 2021 were approved by Order G-165-20, 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 in 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 2020 depreciation expense is calculated as $181.127 million[50], and 2021 depreciation expense is calculated as $190.918 million[51].

7.5 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist[52]. 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, Schedule 11 and 12, FEI has classified its existing rate base deferral accounts in accordance with this classification.

The forecast mid-year balance of unamortized deferred charges in rate base for FEI is a credit of $0.428 million in 2020 and a credit of $19.923 million in 2021.

The 2020 credit balance is driven largely by the balances in several deferral accounts, including the Net Salvage Provision account, the net variance between the Pension and OPEB Funding accounts, Midstream Cost Reconciliation Account (MCRA), Deferred Interest on MCRA / CCRA / RSAM / Gas in Storage account, the Emissions Regulations account, and the Commodity Cost Reconciliation Account (CCRA). The credit balance is offset by Demand Side Management, Greenhouse Gas Reductions Regulation Incentives, Revenue Stabilization Adjustment Mechanism, Gains and Losses on Asset Disposition, and Whistler Pipeline Conversion deferrals.

The 2021 credit balance is driven largely by the balances in several deferral accounts, including the Net Salvage Provision account, the net variance between the Pension and OPEB Funding accounts, Deferred Interest on MCRA / CCRA / RSAM / Gas in Storage account, and the

[50] $189.443 million depreciation expense as calculated in Section 11 - 2020, Schedule 21, Line 5 less $8.316 million amortization of CIAC as calculated in Section 11 - 2020, Schedule 21, Lines 11 and 12.

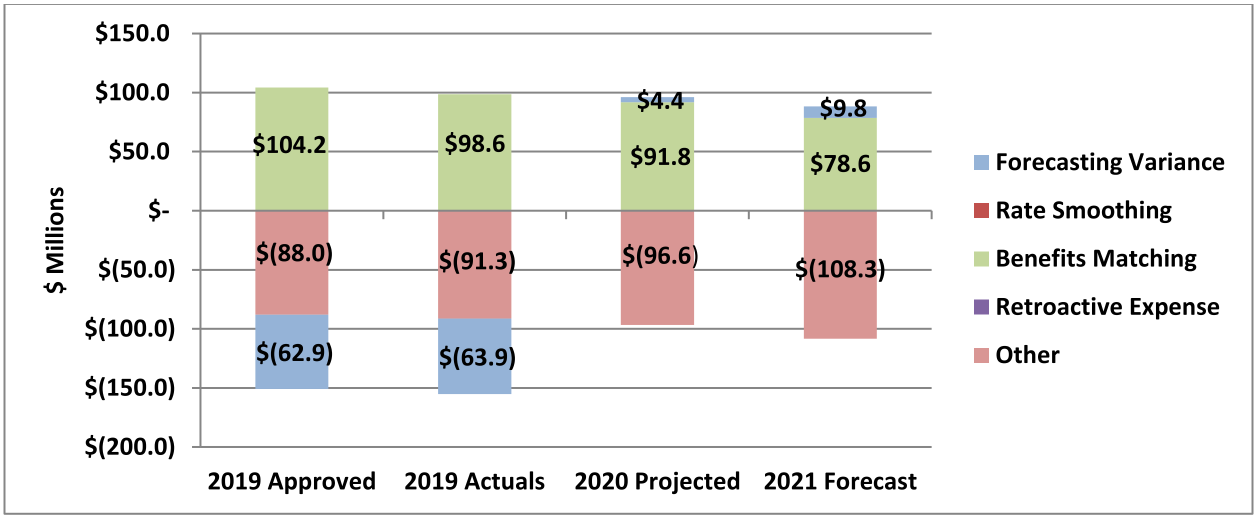
[51] $199.423 million depreciation expense as calculated in Section 11 - 2021, Schedule 21, Line 5 less $8.505 million amortization of CIAC as calculated in Section 11 - 2021, Schedule 21, Lines 11 and 12.

[52] Log No. 53608, Appendix B.

Emissions Regulations account. The credit balance is partially offset by the Demand Side Management, Greenhouse Gas Reductions Regulation Incentives, Revenue Stabilization Adjustment Mechanism, Gains and Losses on Asset Disposition, Whistler Pipeline Conversion deferral and the COVID-19 Customer Recovery Fund deferral.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

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



Based on amortizing the opening deferral account balances using the approved amortization periods, the 2020 amortization expense is calculated as $51.033 million[53] and the 2021 amortization expense is calculated as $89.523 million[54]. 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.

7.5.1 New Deferral Accounts

FEI is seeking approval of four new rate base deferral accounts to capture costs related to the following regulatory processes:

- Annual Reviews for 2020 to 2024 Rates;
- 2022 Long-Term Gas Resource Plan;
- BCUC Initiated Inquiries; and
- The City of Coquitlam Application Proceeding.

[53] Total of Section 11 - 2020, Schedule 11.1, Line 28, Column 6 and Schedule 12, Line 27, Column 6.
[54] Total of Section 11 - 2021, Schedule 11.1, Line 28, Column 6 and Schedule 12, Line 27, Column 6.

1 Table 7-9 below addresses the considerations identified in the Regulatory Account Filing
2 Checklist, as they pertain to the deferral accounts requested in Section 7.5.1.1 to 7.5.1.4 below.

3 **Table 7-9: 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 four new deferral accounts to capture costs related to the Annual Reviews for 2020 to 2024 Rates, 2022 Long-Term Gas Resource Plan, BCUC Initiated Inquiries, and the City of Coquitlam Application Proceeding.
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.
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 MRP index-based 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.

Item	Consideration	Determination
IV	Address:	
a)	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 index-based O&M Expense under the MRP. See section 7.5.1.1 to 7.5.1.4.
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 section 7.5.1.1 to 7.5.1.4. 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.
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 index-based O&M Expense.

Item	Consideration	Determination
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 section 7.5.1.1 to 7.5.1.4.
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. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.5.1.1 Annual Reviews for 2020 – 2024 Rates

FEI is requesting approval to establish a deferral account to capture the costs related to the Annual Reviews for 2020 – 2024 Rates. Consistent with other deferral accounts related to regulatory applications, the Annual Review deferral account will capture costs such as BCUC costs, intervener and participant funding costs, consulting costs, legal fees, and miscellaneous facilities, stationary and supplies costs. FEI forecasts additions of $0.100 million ($0.073 million after tax) in each of 2020 and 2021.

Consistent with past practice, FEI is proposing to amortize costs over one year, whereby costs related to each annual review will be amortized in the subsequent year.

7.5.1.2 2022 Long-Term Gas Resource Plan Application

As directed in Order G-39-19, FEI will file its 2022 Long-Term Gas Resource Plan (LTGRP) on or before March 31, 2022. Consistent with historical and previously approved practice, FEI is seeking a deferral account to capture the costs of external resources required for the 2022 LTGRP that are incremental to the costs in FEI's Base O&M for the LTGRP. Generally, these incremental costs are required to comply with the BCUC directives from the 2010, 2014 and 2017 LTGRP Decisions, to conduct work incremental to that required for past resource plans. These costs are also the result of intermittent activities that are not undertaken every year due to the submission of a resource plan on a multi-year cycle, and are therefore not included in ongoing annual O&M costs and are better managed through a deferral account mechanism.

In addition to the recommendations and directives from the BCUC in their decisions on the 2010, 2014 and 2017 Long Term Resource Plans, FEI was given the following specific directives to be included in its next LTGRP filing, per Order G-39-19:

1. In the next LTGRP filing, FEI is directed to:
    - Update the information filed in this proceeding to respond to the BCUC's directive in the 2014 LTRP Decision to provide an analysis of FEI's End-Use Method as compared to other end-use methods, including an assessment of the of FEI's method compared to other models that incorporate some form of end-use modelling combined with econometric modeling;[162]
    - Provide a detailed explanation of any changes to its demand forecast methodology as it evolves between now and the next LTGRP filing; and
    - Include high level assessment of the effectiveness of the Traditional and End-Use Models compared to actual results.
2. FEI is directed to continue use of its Traditional Method as a comparison to test its End-Use Method until such time as the BCUC approves a new demand forecast methodology.
3. The Panel directs FEI to continue to provide the following information, in the next LTRGP:
    - DSM funding scenarios, reflecting the results of the most recent CPR, that include a "reference" DSM funding scenario with "high DSM" and "low DSM" scenarios that are relative to the reference scenario;
    - An analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:
        - Total Resource Cost/modified Total Resource Cost test results;
        - Utility Cost Test result, expressed as a ratio and $/GJ;
        - Delivery rate impact;
        - Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers; and
        - Estimated gas (GJ) and GHG emission reductions.
4. The Panel directs FEI to provide an update of its analysis of opportunities for DSM to be used to cost-effectively replace or defer infrastructure investments in its next LTGRP.

5. In the next LTGRP, the Panel directs FEI to address the implications for FEI's long-term resource and conservation planning of the 2018 CleanBC plan released by the Government of BC on December 6, 2018 and to provide an update on its analysis of GHG targets. In particular, the Panel expects that FEI should address the long term impacts to FEI of:
   - Initiatives targeting more energy efficient buildings, in terms of gas
   - Requirements for 15 percent of natural gas consumption to be from renewable gas;
   - Industrial electrification, with respect to demand for natural gas;
   - How 2018 CleanBC's plans for clean transportation affect FEI's forecast for its NGT programs; and
   - Other initiatives to be developed by the Government of BC over the next 18 to 24 months.
6. The Panel directs FEI to address security of supply concerns in its next LTGRP.
7. The Panel directs FEI to file its next LTGRP on or before March 31, 2022.

FEI estimates that total costs of the LTGRP application will be $0.850 million ($0.621 million after tax), with $0.295 million ($0.215 million after tax) of costs projected to be incurred in 2020 and a further $0.430 million ($0.314 million after tax) forecast to be incurred in 2021. Table 7-10 provides a detailed summary of the specific cost categories that comprise the total estimated expenditures of $0.850 million for the 2022 LTGRP.

Table 7-10: 2022 LTGRP Estimated Expenditures

Activity	Total Estimated Expenditures
Scenario Development	$ 75,000
Comparison of Demand Forecasting Methodologies	$ 45,000
End-Use Demand Forecast	$ 150,000
Alternative Residential and Commercial Customer Additions Forecast	$ -
Alternative Industrial Customer Additions and Demand Analysis	$ 50,000
Impact of New End-Use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 115,000
Incremental Consultation Activities	$ 50,000
DSM Portfolio Scenario Analysis & Alternative DSM Funding and Savings Scenarios	$ 90,000
Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 80,000
Infrastructure Contingency Plans	$ 20,000
Analysis of Impact on GHG Targets	$ 20,000
Addressing Security of Supply / Resiliency	$ 50,000
Address Implications of the CleanBC Plan / Initiatives being Developed by the Provincial Government	$ 50,000
Additional Regulatory Assistance (if needed)	$ 55,000
Total	$ 850,000

Consistent with past practice, FEI is also requesting approval to capture regulatory application and proceeding costs such as legal fees, intervener and participant funding costs, BCUC costs, required public notification costs, and miscellaneous administrative costs related to the LTGRP Application within the same deferral account. FEI estimates total regulatory and proceeding costs associated with the LTGRP application will be \$0.350 million (\$0.256 million after tax), with \$0.050 million (\$0.037 million after tax) forecast to be incurred in 2021.

FEI will apply for disposition of the account in a future application, following completion of the regulatory process for the 2022 LTGRP.

7.5.1.3 BCUC-Initiated Inquiries

FEI is seeking a deferral account to capture, in aggregate, costs associated with its participation in BCUC-initiated inquiries and proceedings for the purpose of determining provincial regulatory policy or ensuring consistency of treatment among utilities. These costs represent BCUC costs, intervener and participant funding costs, consulting costs and external legal fees. The following proceedings are currently included or will be included in this deferral account:

- BCUC Indigenous Utilities Regulation Inquiry, which concluded in April 2020. To date, FEI has incurred \$0.487 million (\$0.356 million after tax) and anticipates additional costs of $0.125 million in 2020 related to the issuance of the final report and participant funding costs.

- BCUC Inquiries, which include the Municipal Energy Utilities Inquiry and Thermal Energy Systems Guidelines Review. To date, FEI has incurred $0.096 million ($0.070 million after tax). FEI forecasts further costs of $0.070 million in 2020 and $0.100 million in 2021 related these inquiries.

FEI proposes to include the costs of these and future BCUC-initiated inquiries in a single deferral account in order to reduce the number of individual deferral account requests. Further, FEI proposes to amortize costs in the year following when the expenses are forecast.

7.5.1.4 City of Coquitlam Application Proceeding

FEI is requesting approval for a deferral account to capture costs related to the ongoing dispute with the City of Coquitlam regarding the use of land that arose from the LMIPSU Project. As part of the BCUC's approval of the LMIPSU CPCN, FEI was granted approval to proceed with the LMIPSU Project; however, the City of Coquitlam was unwilling to issue the necessary permits. FEI filed an application to the BCUC and received a decision to direct the use of the land without the City of Coquitlam's permits. The City of Coquitlam challenged the decision both through the BCUC on reconsideration of their decision and by filing an application for Leave to Appeal with the Court of Appeal. The BCUC's reconsideration process has been completed, dismissing the City's Reconsideration Application. However, the regulatory process related to the allocation of any pipeline removal costs is ongoing. The City of Coquitlam is also pursuing its Leave to Appeal.

To date, FEI has incurred costs of $0.285 million ($0.208 million after tax) for legal fees, BCUC costs and consulting fees. FEI anticipates further costs related to this proceeding and any ongoing legal proceedings through the courts. At this time, these costs are estimated to be an additional $0.100 million ($0.073 million after tax) in 2020 and $0.250 million ($0.183 million after tax) in 2021; however, these costs are only a best estimate at this time and there is uncertainty over the remainder of the process.

Further, FEI proposes to amortize these costs over 3 years beginning January 1, 2021. FEI believes a three-year amortization period is appropriate as it is consistent with the recovery period of other similar regulatory proceeding applications and it balances potential rate impacts with the benefits of the application.

7.5.2 Existing Deferral Accounts

In the discussion below, FEI provides information on three existing deferral accounts and requests an amortization period for one of them.

7.5.2.1 COVID-19 Customer Recovery Fund Deferral Account

In June 2020, FEI received approval through Order G-132-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

a) any bill payment deferrals provided to customers due the COVID-19 pandemic and subsequent payments of those deferred amounts;

b) any bill credits provided to customers due to the COVID-19 pandemic; and

c) any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2020 and 2021 financial estimates and descriptions for each of the three items for inclusion in the COVID-19 Customer Recovery Fund Deferral Account.

a) Bill payment deferrals provided to residential and small commercial customers

The 3-month bill payment deferral program has been offered to residential and small commercial customers affected by COVID-19 from April to June 2020. The bill payment deferrals are to be repaid by customers over a 12-month period with such repayments beginning in July 2020.

Table 7-11: 2020 Bill payment deferral forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Payment Deferrals	**2020**	-	1,625	-	-	1,625
COVID-19 Customer Recovery Fund - Bill Payment Deferrals	**2021**	1,625	(1,625)	-	-	-

The deferral account gross additions of $1.625 million related to this customer relief offering have been estimated as the outstanding customer accounts receivable balances of $3.652 million as of July 2020, less the estimated customer repayments from July 2020 through to the end of 2020. As customers are expected to repay the balances over a 12-month term, beginning in July 2020, there is not expected to be an ending balance of bill payment deferral balances as at the end of 2021.

Any of the customers enrolled in the bill payment deferral program that are unable to repay their outstanding balances will be designated as unrecoverable revenue. This change in classification will entail a reduction in the bill payment deferral portion of the deferral account in this section (a) and will be reallocated as an addition to the unrecovered revenue (section c) component. There could be customers that default on their repayment of the bill deferral arrangements and these would also be allocated to the unrecovered revenue (section c). No such defaults have been forecasted in section (a) as they are assumed to be incorporated in the estimates provided in section (c) associated with unrecovered revenue.

b) Bill credits provided to small commercial customers

The 3-month bill credit program offered to small commercial customers for April through June 2020 has been estimated using the customer balances of $0.918 million as of July 2020.

Table 7-12: 2020 Bill Credit Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Credits	**2020**	-	918	(248)	-	670
COVID-19 Customer Recovery Fund - Bill Credits	**2021**	670	-	-	-	670

While the bill credits are available for the three-month period from April through June 2020, the forecasted balance of bill credits are still subject to change after June 2020. This is primarily due to the expectation that there could still be small commercial customers that have yet to apply for bill credit relief for the qualifying three-month period, as well as certain billing cycles yet to be completed.

c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

Unrecovered revenues are representative of accounts receivable balances that are determined to be uncollectible due to COVID-19 and therefore include the write-offs of bad debts. These forecasted balances are meant to represent the unrecovered revenues specific to COVID-19 that are recognized in the deferral account and therefore are in excess of the normal course forecasted bad debt expense that is recognized in indexed-based O&M. While FEI has currently forecasted the bad debt expense to be recognized in indexed-based O&M for 2020 and 2021 as representative of the normalized bad debt expense that was embedded in the Base O&M, the actual bad debt expense recognized in O&M could differ. This is in part due to the timing of recognizing the bad debt expense in O&M versus the write-offs of bad debts in the deferral account, as well as the uncertainty around the duration and significance of the pandemic on customers' ability to pay their bills.

Table 7-13: 2020 Unrecoverable Revenue Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Unrecoverable Revenue	**2020**	-	2,026	(547)		1,479
COVID-19 Customer Recovery Fund - Unrecoverable Revenue	**2021**	1,479	3,683	(994)	-	4,168

The unrecovered revenue recorded in the deferral account will include:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay; and

- any unrecovered revenue from all customer classes due to COVID-19, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings.

There has been a minimal amount of confirmed customer bad debt write-offs relating to COVID-19 in the first four to five months since the relief options have been offered to customers. While there still exists uncertainty around the effects of COVID-19 on customers' ability to make payments for current and future billed revenues, it is probable and reasonable to expect that unrecovered revenue will materialize in the last half of 2020 and through 2021. Accordingly, FEI has developed a methodology to estimate additions to the deferral account by applying an estimated loss rate on forecasted 2020 revenues to determine the potential unrecovered revenue from customers resulting from the COVID-19 pandemic. To clarify, the ending balance of $4.168 million is based on the estimated bad debt write offs calculated on revenues billed in 2020 and does not take into account bad debt write offs associated with revenue billed in 2021 or beyond. Due to the significant uncertainty around the extent and duration of the pandemic on FEI's customers' ability to pay in the future, there could also be unrecovered revenues that are recognized in the deferral account beyond the forecast periods of 2020 and 2021.

For residential and small commercial customers, the loss rate took into account the relative increase in the forecasted 2020 unemployment rate for BC from 5.0 percent prior to the pandemic to 8.2 percent. Similarly, there was a loss rate applied for industrial and large commercial customers which incorporated the forecasted 2020 GDP decrease in BC of 4.5 percent. The loss rate was then applied to forecasted revenues from March 2020 through to December 2020. The unemployment and GDP indicators are macroeconomic factors based on forecasts from five financial institutions and corroborated through the Conference Board of Canada.

Applying macroeconomic factors to estimating unrecoverable revenues is consistent with the principles for external financial reporting. US GAAP ASU 2016-13 *Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments* discussed in Section 12.3.1.1 of this Application requires entities to consider historical experience, current conditions and reasonable forecasts to determine the expected amount of credit losses that will occur. Accordingly, FEI has estimated $2.0 million and $3.7 million of unrecoverable revenue additions for 2020 and 2021, respectively, to the COVID-19 Customer Recovery Fund Deferral Account.

While the forecasts of the unrecovered revenue additions rely on estimates and broader macroeconomic factors, the actual amounts that accumulate in the deferral account are expected to be representative of balances that are attributable to specific customers that cannot make payment due to COVID-19.

FUTURE DISPOSITION OF DEFERRAL ACCOUNT BALANCES

At the time of the original COVID-19 Customer Recovery Fund Deferral Account application in early April 2020, there was significant uncertainty around the effect of the pandemic and the overall economic effect on FortisBC's customers. The combination of the programs offered to customers and the deferral account have been successful and are working as intended to the date of this filing. However, there continues to be uncertainty around future unrecovered revenues and the possibility as to whether further extensions or additional relief offerings will be required for the balance of 2020 and into 2021.

Rather than suggesting partial disposition for the three items in the deferral account, FEI recommends a more comprehensive approach to the disposition of the deferral account, particularly given that the effects of COVID-19 on these measures could occur over multiple years. Therefore, FEI is not yet proposing an amortization period for the deferral account in 2020 or 2021. FEI has forecasted additions to the deferral account for 2020 and 2021 and will propose a disposition of the deferral account in the Annual Review of 2022 Delivery Rates filing, to take place in 2021.

7.5.2.2 Greenhouse Gas Reduction Regulation (GGRR) Incentives

Through the term of the 2014-2019 PBR Plan, FEI included a discussion of the incentives distributed via the Greenhouse Gas Reduction Regulation (GGRR) in a separate appendix. FEI has eliminated that particular appendix and included a discussion of the GGRR incentives here.

The GGRR, authorized under the *Clean Energy Act*, enables FEI to provide grants or zero-interest loans for the purchase of eligible natural gas vehicles operating in British Columbia and for related safety practices and maintenance facility upgrades up to $177.9 million in total (Prescribed Undertaking 1), plus an additional $40 million in total for those NGT customers that use either CNG or LNG wholly derived from biomass or biogas. The GGRR also includes up to $6.1 million for the purchase of generators, boilers, burners, or kilns that use natural gas to produce electricity (Prescribed Undertaking 2(3.2)) as well as up to $5 million for feasibility and development costs in relation to shore-side assets (Prescribed Undertaking 2(3.6)).

Table 7-14 below provides a summary of GGRR incentives forecast to be distributed[55] under Prescribed Undertaking 1, Prescribed Undertaking 2(3.2), and Prescribed Undertaking 2(3.6) for 2019 Approved and Actual, 2020 Projected, and 2021 Forecast by category. The GGRR incentives will be recorded to the GGRR Incentives Deferral Account as approved by Order G-161-12. The balance in this deferral account will be recovered in the delivery rates of non-bypass customers over a period of ten years, which was also approved by Order G-161-12.

[55] 2019 Approved is the forecast incentives to be distributed in the 2019 Annual Review, and 2019 Actual are the actual incentives distributed in 2019.

Table 7-14: GGRR Incentives

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Total Vehicle Incentives	$ 3.500	$ 2.112	$ 2.000	$ 2.000
2	Marine, Mining & Rail Incentives	6.625	3.875	2.125	5.625
3	Remote Power	-	-	-	-
4	Safety Practices and Maintenance Facilities Incentives	0.700	0.007	0.200	0.200
5	Admin, Education, Safety Training	1.000	1.594	1.400	1.000
6	Shore-Side Assets Feasibility and Development	0.300	0.659	-	-
7	**Total GGRR Incentives**	**$ 12.125**	**$ 8.247**	**$ 5.725**	**$ 8.825**

7.5.2.3 2020 Revenue Requirement

As part of the Annual Review for 2018 Delivery Rates Application, FEI received approval through Order G-196-17 to establish the 2020 Revenue Requirement Proceeding deferral account to capture the costs related to filing that application and the related regulatory proceeding. Further, FEI noted that it would request an amortization period for this account in a future application.

Consistent with past practice, FEI is proposing to amortize this deferral account over five years commencing January 1, 2020, which represents the period covered by the MRP Application.

FEI notes that it has renamed the deferral account from 2020 Revenue Requirement Proceeding to 2020–2024 MRP Application to better reflect the nature of the deferral account.

7.6 *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 through Order G-165-20.

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 component of other working capital is gas in storage and transmission line pack, which are forecast on a 13-month average basis using the approved costs embedded in the 2020 Q2 gas cost report and historical volumes. All other 2020 amounts are projected based on 2019 levels, while also including six months of actual results for 2020. 2021 amounts are based on similar inputs and include inflation where applicable.

7.7 *SUMMARY*

FEI's rate base includes the impact of formula-driven growth capital expenditures, regular capital expenditures that are forecast outside of the formula, and CPCNs 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, and discussed four new accounts and three existing accounts in this section of the Application. Finally, the rate base includes other working capital, composed 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 61.5 percent debt and 38.5 percent equity and Return on Equity (ROE) of 8.75 percent approved by Order G-129-16. The 2020 Projection for financing costs, including the interest expense on issued long- 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 rates for 2020 and 2021 (which are equal to its after-tax weighted average cost of capital) are 5.47 percent and 5.47 percent, respectively. 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*

The Company 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-129-16, the BCUC has approved a benchmark capital structure of 61.5 percent debt and 38.5 percent equity with an allowed ROE of 8.75 percent, effective January 1, 2016, 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- and short-term debt.

8.3.1 Long-Term Debt

FEI is a public issuer of long-term debt. In August 2019, FEI issued long-term debt of $200 million at a rate of 2.82[56] percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FEI completed another $200 million long-term debt issuance in July 2020 at a rate of 2.54 percent[57]. The proceeds of the 2020 issuance will be used to finance or refinance, in part or in full, new or existing green projects that are eligible under FortisBC's Green Bond Framework[58]. FEI plans to issue additional long-term debt of approximately $200 million in 2021 to finance FEI's capital expenditure program and repay existing indebtedness. The 2021 debt issuance is reflected in the financial schedules in July 2021 at a rate of 3.30 percent[59]. The exact timing, amount and

[56] Section 11 – 2020 and Section 11 - 2021, Schedule 27, Line 15 (effective rate 2.857 percent).
[57] Section 11 – 2020 and Section 11 - 2021, Schedule 27, Line 16 (effective rate 2.588 percent).
[58] Refer to FortisBC's Green Bond Framework at https://www.fortisbc.com/about-us/investor-centre.
[59] Section 11 - 2021, Schedule 27, Line 17 (effective rate 3.353 percent).

rate of the 2021 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 the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

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 $700 million committed credit facility that matures in August 2024[60]. The credit facility provides FEI with short-term liquidity to fund FEI's capital program and working capital requirements. The Company also issues letters of credit as part of this facility. In March 2020, FEI entered into a new $55 million letter of credit facility maturing in March 2022 to support its letters of credit.

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

The 3-month T-Bill forecast for 2020 and 2021 has been significantly impacted by the COVID-19 pandemic and is projected to decrease from 2.05 percent in 2019 to approximately 0.51 percent in 2020 and 0.45 percent in 2021. For 2020 and 2021, FEI has also forecast other financing fees, which includes the fees that it incurs for its letters of credit under the $700 million credit facility and the newly signed letter of credit facility discussed in Section 8.3.2, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

[60] On August 15, 2019, credit facility extended to August 24, 2024.

Table 8-1: Short Term Interest Rate Forecast

FEI Short Term Interest Rate	Approved 2019	Actual 2019	Projected 2020	Forecasted 2021
3-Month T-Bill Rate [1]	2.05%	1.79%	0.51%	0.45%
Spread to CDOR	0.42%	0.42%	0.44%	0.44%
CDOR Rate	2.47%	2.21%	0.95%	0.89%
Spread to CP	-0.17%	-0.17%	-0.22%	-0.22%
CP Dealer Commission	0.10%	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**2.40%**	**2.14%**	**0.83%**	**0.77%**
Fixed Financing Fees [2]				
Standby fee on Undrawn Credit [3]	0.54%	0.76%	0.50%	0.86%
Renewal Fee on Undrawn Credit	0.15%	0.30%	0.18%	0.33%
Other Financing Fees			0.13%	0.23%
ST Interest Rate on Fixed Financing Fee	**0.69%**	**1.06%**	**0.82%**	**1.42%**
FEI Short Term Rate	**3.10%**	**3.19%**	**1.65%**	**2.19%**

Notes:

[1] 3-Month T-Bill Rate for 2020 based on a composite of actual historical rates up to June 30, 2020 and forecasted rates for the remainder of the year.

[2] Fixed financing fees represent the costs of maintaining $700 million credit facility and letter of credit facility, which are fixed fees regardless if FEI draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 16 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FEI will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FEI's existing and forecast borrowing costs on long- 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 2020 and 2021 long-term debt schedules for FEI can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FEI applies AFUDC to projects that are greater than 3 months in duration and greater than $100 thousand. Based on the above information, FEI's AFUDC rates for 2020 and 2021 (which are equal to its after-tax weighted average cost of capital) are 5.47 percent and 5.47 percent, respectively. The calculation of the rates are shown in the following table.

Table 8-2: Calculation of AFUDC Rates for 2020 and 2021

Line No.	Description	2020 Weight	2020 Pre-Tax Rate	2020 After-Tax Rate	2020 Earned Return	2021 Weight	2021 Pre-Tax Rate	2021 After-Tax Rate	2021 Earned Return
1	Short Term Debt	4.41%	1.65%	1.20%	1.65%	2.36%	2.19%	1.60%	2.19%
2	Long Term Debt	57.09%	4.91%	3.58%	4.91%	59.14%	4.78%	3.49%	4.78%
3	Common Equity	38.50%	11.99%	8.75%	8.75%	38.50%	11.99%	8.75%	8.75%
4									
5	Weighted Average	100.00%	7.49%	5.47%	6.25%	100.00%	7.49%	5.47%	6.25%

8.4 *SUMMARY*

FEI's equity financing and ROE have been forecast for 2020 and 2021 at the same percentages as approved by Order G-129-16. 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; both of these rates are forecast to decrease in 2020 and 2021 as compared to 2019 Approved.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FEI's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2020, property taxes are projected to increase by 0.6 percent from 2019 Approved, with a further increase of 5.7 percent in 2021 compared to the 2020 Projected amount. Income tax is forecast to decrease by 32.3 percent in 2020 compared to 2019 Approved, and then increase by 50.5 percent in 2021 compared to the 2020 Projected amount.

9.2 PROPERTY TAXES

Property taxes for 2020 and 2021 of $67.959 million and $71.811 million, respectively, incorporate Company 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 Forecasts ($ millions)

Line No	Asset Type	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Distribution Assets	$ 23.912	$ 24.685	$ 25.553	$ 25.473
2	Transmission Assets	17.844	18.602	20.049	21.012
3	Gas Storage Assets	8.560	7.926	6.565	8.185
4	Manufactured Gas Assets	0.033	0.035	0.038	0.037
6	General Assets	4.606	4.252	4.223	4.478
7	In-Lieu	12.333	12.013	11.293	12.423
8	OGC Fees	0.290	0.287	0.281	0.286
9	Total Property Taxes	$ 67.578	$ 67.800	$ 68.002	$ 71.894
10	Less: Property Tax Transferred to BVA	(0.019)	(0.019)	(0.043)	(0.083)
11	Net Property Tax Expense	$ 67.559	$ 67.781	$ 67.959	$ 71.811
12					
13	2019 Actual to Approved		0.3%		
14	2020 Projected Change from 2019 Approved			0.6%	
15	2021 Forecast Change from 2020 Projected				5.7%

Projected 2020 property taxes in the table above include actual payments of $60.176 million and projected payments of $7.826 million for the remainder of the year. Property Taxes in 2020 property taxes are projected to increase by 0.6 percent compared to 2019 Approved, with a further forecasted increase in 2021 of 5.7 percent compared to 2020 Projected. In general, the 2021 increase from 2020 Projected is due to construction activities, market value increases and changes in tax policies of local taxing authorities. The most significant forecast drivers of the changes are as follows:

9. ***Changes in Tax Rates***. Tax Rates are expected to change for 2021 as follows:
   a) Municipal rates are expected to increase by 0.25 percent for Lower Mainland municipalities, and 0.50 percent for all other municipalities;
   b) School rates are expected to decrease by 2.5 percent to offset assessment increases resulting from the BC Assessment Utility Class model updates;
   c) Rural rates are expected to increase by 1.0 percent;
   d) Tax rates on First Nations are expected to increase 0.50 percent for Coastal First Nations and 0.25 percent for Interior and Vancouver Island First Nations; and
   e) Other rates are expected to increase by 1.0 percent.
10. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 10.5 percent based on actual revenues to be reported. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall increase in revenues reported to municipalities increases the grants in-lieu of taxes due.
11. ***Changes in Assessed Values***. Forecast changes in the assessed values of FEI's property are based on the increases that BC Assessment was proposing at the time the forecast was developed. These include:
    a) A 2.0 percent increase in assessed values of distribution lines and services plus additional new construction;
    b) A 9.4 percent increase in assessed values of transmission lines as a result of a systematic review of all of BC Assessments linear rates;
    c) A 2.0 percent increase in assessed values for LNG assets; and
    d) Land value changes which are expected to increase on average 2.0 percent for both right of ways and market value for properties owned in fee simple.

Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected 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 2020 and 2021, which is unchanged from 2019. 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.

Income tax for 2020 is projected to decrease by $17.128 million or 32.3 percent compared to 2019 Approved and then increase by $18.086 million or 50.5 percent in 2021 compared to the 2020 Projected amount. The 2020 decrease is primarily due to a decrease to adjustments to taxable income from the Federal government's Accelerated Investment Incentive regime as discussed below. In 2021, the income tax increase is primarily due to an increase in delivery margin required mainly to offset an increase in amortization of deferred charges.

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

All other differences in income tax expense will affect the achieved ROE and be subject to earnings sharing.

9.4 *LIQUEFIED NATURAL GAS (LNG) INCOME TAX*

On October 21, 2014, the Provincial government introduced an LNG income tax on net income from LNG facilities in BC. The new LNG income tax was expected to apply to income from liquefaction activities at, or in respect of, LNG facilities in BC, for taxation years beginning on or after January 1, 2017, but was never proclaimed into force.

On April 11, 2019, British Columbia Bill 10 received royal assent and repealed the LNG income tax. In conjunction with the repeal of the LNG income tax legislation, the Provincial government also implemented a Natural Gas Tax Credit (NGTC) against the current 12 percent BC corporate income tax. The NGTC is effectively equal to the lesser of (i) 3.0 percent of the cost of gas owned and liquefied by the taxpayer at the LNG facility and (ii) the BC corporate income tax payable by the taxpayer from all sources (not just LNG income), but cannot be greater than the amount that would reduce the effective BC corporate income tax rate to less than 9 percent. In order for FEI to qualify for the NGTC, the corporation must operate a "major LNG facility" as defined in the NGTC Regulation. FEI has reviewed the definition of "major LNG facility" and noted that none of its facilities currently meet the 2 million LNG production threshold and therefore does not qualify to receive any NGTC.

9.5 *ACCELERATED INVESTMENT INCENTIVE*

On November 21, 2018, the Federal government introduced the Accelerated Investment Incentive regime, which enabled FEI to claim additional Capital Cost Allowance (CCA) deductions in the year of addition for all qualifying expenditures made after November 20, 2018 and before January 1, 2028. The impact of the additional CCA deductions has been incorporated in tax forecasts for 2020 and 2021. The benefits of the additional CCA deductions for 2018 and 2019 were included in the Flow-through deferral account and will be returned to customers through amortization of the deferral account balance.

9.6 *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 *EARNINGS SHARING*

In the MRP Decision (at page 82) the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers.

As discussed in Section 1.1, FEI is proposing to set 2020 permanent rates at existing interim levels by capturing the revenue requirement difference in the 2017 & 2018 Revenue Surplus deferral account. The revenue requirement for 2020 includes an amount for earnings sharing related to the Actual 2019 results from the final year of the 2014-2019 PBR Plan, the details of which are discussed in Section 14.

As also discussed in Section 1.1, FEI is not projecting any earnings sharing from 2020 to be included in 2021 rates, as FEI anticipates relatively minor formulaic O&M savings in 2020 for a variety of reasons, such as the inclusion of a 0.5 percent X-Factor in the calculation of Formula O&M, as directed by the BCUC in the MRP Decision. Further, FEI has included actual amounts up until June 30, 2020 within its Projected 2020 revenue requirement throughout this Application, and is not projecting any further variances for the remainder of the year from the amounts included in this Application. While many of these items are treated as flow-through and therefore the variances do not impact earnings sharing, certain forecast items, such as components of Other Revenue and depreciation, are subject to earnings sharing. For the foregoing reasons, FEI is not projecting any earning sharing (i.e., 50 percent of the variance between achieved ROE and allowed ROE) from 2020 to be included in the 2021 rates. An adjustment to include the difference between the projected amount of zero and final actual amounts of earning sharing from 2020 will be trued-up in 2021 and amortized in 2022 rates.

10.2 *RATE RIDERS*

There are two delivery rate riders that are set each year through the annual review process. These are the BVA Rate Rider and the RSAM Rate Riders. Additionally, pursuant to the MRP 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 MRP to support FEI's Clean Growth Innovation Fund (CGIF) activities.

10.2.1 BVA Rate Rider

The 2020 BVA rate rider was approved on a permanent basis by Order G-307-19. The following supports the BVA rate rider for 2021.

On August 12, 2016, the BCUC issued Order G-133-16 and the accompanying Decision in the matter of the Biomethane Energy Recovery Charge (BERC) Rate Methodology Application (2016 Biomethane Decision). The 2016 Biomethane Decision approved the Short Term BERC rate based on a premium of $7 per GJ above the Conventional Gas Cost (defined as the sum of the Commodity Cost Recovery Charge, the carbon tax and any other taxes applicable to conventional natural gas sales). The Long Term BERC rate is to be set at a $1 per GJ discount to the Short Term BERC rate.

FEI also received approval to amortize/transfer the net of tax year-end balance in the BVA, after adjustment for the value of unsold biomethane quantities, to a BVA Rate Rider Account for recovery from, or refund to, all non-bypass customers via a delivery rate rider effective January 1 of the subsequent year.

In the 2016 Biomethane Decision, FEI was directed to provide the following information:

- A continuity schedule showing the breakdown of the forecast December 31st balance in the BVA to be recovered by the BVA Rate Rider by year including sufficient supporting details.
- The calculation of the BVA Rate Rider by rate class.
- A continuity schedule showing the forecast, actual and variance (actual – forecast) biomethane revenues and volumes sold (GJ) by rate class, type of contract (short term/long term) and year.
- Number of customers in each rate class.

FEI provides the requested information below for the projected closing 2020 balance of the BVA rate rider account, and the calculation of the BVA Rate Riders for 2021.

10.2.1.1 BVA Rate Rider Account

The BVA balance at the end of December 31, 2020 is projected to be a debit of $4.702 million before-tax[61]. This balance consists of the projected $9.167 million in costs to acquire biomethane less $4.465 million of recoveries by way of the Biomethane Energy Recovery Charge (BERC). FEI projects no remaining inventory of biomethane for 2020.

The amount transferred from the BVA to the BVA rate rider account is determined on an after tax basis. The after tax balance in the BVA before transfer to the BVA rate rider account is projected to be $3.432 million[62].

The following table summarizes the BVA rate rider account and shows both the projected after tax ending 2020 balance of zero and the $3.432 million[63] transfer to the BVA rate rider account.

[61] Table 10-1, Line 16.
[62] Table 10-1, Line 25.
[63] Table 10-1, Line 27.

Table 10-1: BVA Rate Rider Account

Line No	BVA Continuity	Note	2020 Projected (a)	Reference
			($000s)	
1	**BVA Opening Balance**	(b)		
2	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		$ 1.5	
3	Pre-Tax Adjustment for Unsold Biomethane		(1.5)	
4	Pre-Tax Adjustment for Unsold Biomethane		$ -	Line 2 + Line 3
5				
6	Tax Recovery		-	- Line 4 x Line 18
7	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ -	Line 4 + Line 6
8				
9	**BVA BVA Activities:**			
10	Biomethane Costs Incurred		$ 9,167.0	
11	Biomethane Costs Recovered		(4,465.0)	
12	Total Activities - Pre-Tax		**$ 4,701.9**	Line 10 + Line 11
13				
14	Pre-Tax Balance of Unsold Biomethane	(c)	$ 0.0	
15	Pre-Tax Balance After Adjustment for Unsold Biomethane		4,701.9	Line 12 - Line 14
16	**BVA Ending Balance**		**$ 4,701.9**	Line 14 + Line 15
17				
18	Tax Recovery Rate		27%	
19				
20	Tax Recovery on Balance of Unsold Biomethane		$ (0.0)	- Line 14 x Line 18
21	Tax Recovery on Balance after adjustment		(1,269.5)	- Line 15 x Line 18
22				
23	After-Tax Balance of Unsold Biomethane		0.0	Line 14 + Line 20
24	After-Tax Balance After adjustment for Unsold Biomethane		3,432.4	Line 15 + Line 21
25	**Net of Tax BVA Balance before Transfer to BVA Rider Account**		**$ 3,432.4**	Line 23 + Line 24
26				
27	**Transfer to BVA Rate Rider Account**	(d)	**$ (3,432.4)**	- Line 24
28				
29	**Net of Tax Balance (After transfer to BVA Rider Account)**		**$ 0.0**	Line 25 + Line 27

Notes

(a) The annual forecast is an updated 2020 forecast including the BVA impact approved in the MRP desion

(b) Recorded opening balance reconciles to the December 31, 2019 balance in the FortisBC Energy Inc. 2019 BVA Status Report.

(c)

Calculation of Adjustment for Unsold Biomethane	2019 Recorded	2020 Projected
Beginning Quantity Unsold Biomethane (in TJ)	-	0.1
Biomethane Purchased (in TJ)	315.2	423.7
Biomethane Sold (in TJ)	(315.0)	(423.8)
Ending Total Biomethane Unsold (in TJ)	0.1	0.0
BERC rate in effect at forecast (in $/GJ)		
January 1st effective BERC rate (in $/GJ)	$ 10.535	$ 10.535
Value of Unsold Biomethane at December 31, 2020	$ 1.5	$ 0.0

(d) Pursuant to Order G-133-16, and the Decision issued concurrently, the net of tax balance at December 31, 2020, after adjustment for the value of unsold biomethane quantities, was transferred to the BVA Rate Rider Account for recovery from / refund to all non-bypass customers.

10.2.1.2 BVA Rate Rider Calculation

The cumulative BVA rate rider for recovery in 2021 is forecast at $4.298 million and is recovered from non-bypass customers through a rate rider based on forecast 2021 volumes. The $4.298 million to be collected consists of the projected 2019 recovery variance credit of $404.4 thousand[64] plus the $3.432 million after tax debit transferred from the BVA grossed up to a before tax debit value of $4.702 million[65].

To calculate the BVA rate rider, the projected BVA rate rider account balance of $4.298 million is divided by the 2021 forecast non-bypass customer volume of 194,999 TJs, which results in a BVA rate rider of $0.022 per GJ. Any difference between the actual and forecast BVA rate rider amount collected will be trued up in the subsequent year. Details of the BVA rate rider calculation are provided in Table 10-2 below.

[64] The $404.4 thousand represents a combined adjustment for the 2019 actual and projected BVA balance transfer variance and the 2020 recovery variance because of the 2020 volume projection variance.

[65] Table 10-2, Line 5.

Table 10-2: 2021 BVA Rate Rider Calculation

Line No	Particulars	BVA Rider Projected 2020 ($000s) Net of Tax	BVA Rider Projected 2020 ($000s) Grossed Up	Non-Bypass Forecast 2021 Vol (TJ)
1	**BVA Rider Account Balance**			
2	**BVA Balance Transfer Deferral Account Balance Dec 31, 2019 - Actual**	2,467.7	$ 3,380.5	
3	Less Projected 2020 BVA Rider recoveries for 2019 using 2020 Projected Non-bypass volumes	(2,762.9)	(3,784.9)	
4	**2020 projected true up adjustment - 2019 projected recovery variance**	(295.2)	(404.4)	
5	BVA Balance transferred to BVA Balance Transfer Deferral Account Dec 31, 2020 - Projected	3,432.4	$ 4,701.9	
6	**BVA Balance Transfer Deferral Account Balance Dec 31, 2020 - Projected**	**3,137.2**	**4,297.5**	**194,999.1**
7				
8	**Residential**			
9	Rate Schedule 1		$ 1,748.4	79,332.3
10	**Commercial**			
11	Rate Schedule 2		$ 637.7	28,937.2
12	Rate Schedule 3		$ 577.5	26,203.9
13	Rate Schedule 23		$ 107.5	4,877.8
14	**Industrial**			
15	Rate Schedule 4		$ 3.3	148.9
16	Rate Schedule 5		$ 180.0	8,168.9
17	Rate Schedule 6		$ 0.5	23.4
18	Rate Schedule 7		$ 130.6	5,924.2
19	Rate Schedule 22- Firm Service		$ 230.0	10,434.2
20	Rate Schedule 22- Interruptible Service		$ 350.4	15,899.6
21	Rate Schedule 25		$ 226.0	10,252.7
22	Rate Schedule 27		$ 105.7	4,796.0
23				
24	**Total BVA Rider (Non-Bypass)**		**$ 4,297.5**	**194,999.1**
25				
26	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.022**	
27	(Line 6 divided by Line 24) $4,297.5/194,999.1 TJ = $0.022 GJ			

In the 2016 Biomethane Decision, FEI was directed to provide a continuity of forecast, actual and variance (actual - forecast) biomethane (BERC) revenues and volumes sold by rate schedule, and type of contract.

The following table breaks down the BERC revenues and volumes by rate schedule and by short-term and long-term contracts. In 2020, the projected recoveries are $4.465 million attributable to sales volumes of 423.8 TJs from 10,493 RNG customers. The expected sales volume from existing and projected long-term contracts is included in the 2020 projected volume and revenue in Table 10-3 below.

Table 10-3: BERC Revenue and Volume

Line No	Volume and Revenue	2019 Actual	2019 Projected	2019 Variance	2020 Projected
1	**Volume (TJ)**				
2	**Short-term**				
3	Rate Schedule 1B	113.4	107.1	6.3	119.5
4	Rate Schedule 2B	18.9	16.6	2.2	16.9
5	Rate Schedule 3B	17.1	19.5	(2.4)	19.3
6	Rate Schedule 5B	22.0	22.5	(0.5)	89.5
7	Rate Schedule 11B	50.7	50.7	-	14.0
8	Rate Schedule 30	-	-	-	-
9	Sub-total	222.0	216.4	5.6	259.3
10					
11	**Long Term**				
12	Rate Schedule 11B	93.0	93.0	-	164.6
13	Sub-total	93.0	93.0	-	164.6
14					
15	**Total Sales Volume (TJ)**	315.0	309.4	5.6	423.8
16					
17	**Recoveries ($000s)**				
18	**Short-term**				
19	Rate Schedule 1B	$ 1,166.3	$ 1,098.3	$ 68.0	$ 1,259.1
20	Rate Schedule 2B	194.7	170.4	24.3	178.1
21	Rate Schedule 3B	175.5	199.4	(23.9)	203.8
22	Rate Schedule 5B	226.5	230.9	(4.4)	942.6
23	Rate Schedule 11B	510.65	519.5	(8.8)	147.7
24	Rate Schedule 30		-	-	-
25	Sub-total	2,273.6	2,218.5	55.1	2,731.4
26					
27	**Long Term**				
28	Rate Schedule 11B	930.5	927.4	3.1	1,733.6
29	Sub-total	930.5	927.4	3.1	1,733.6
30				-	
31	**Total Sales**	$ 3,204.0	$ 3,145.9	$ 58.1	$ 4,465.0

In the 2016 Biomethane Decision, FEI was also directed to provide the number of customers by rate schedule. The following table sets out the 2020 Projected number of renewable natural gas customers by rate schedule.

Table 10-4: RNG Customers by Rate Schedule

2020 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short Term	
Rate Schedule 1B	10,273
Rate Schedule 2B	198
Rate Schedule 3B	15
Rate Schedule 11B	2
Rate Schedule 5B	2
Rate Schedule 30 Off System	-
Long Term	
Rate Schedule 11B	3
Total	**10,493**

In summary, the 2021 BVA rate rider attributable to the cumulative December 31, 2020 transfers from the BVA is $0.022 per GJ recoverable from all non-bypass customers.

10.2.2 RSAM Rate Riders

The RSAM Rate Riders collect or refund the previous year's projected RSAM balance from Rate Schedule 1, 2, 3 and 23 customers over two years. The projected balance in the RSAM account at the end of 2020 is a debit of $17.667 million. The calculation of the 2021 RSAM riders is shown in Table 10-5.

Table 10-5: 2021 RSAM Riders

2020 RSAM + Interest Closing Balance ($000)	17,667
Amortization Period (Years)	2
2021 Amortization Post-Tax ($000)	8,834
Tax Rate	27%
2021 Amortization Pre-Tax ($000)	12,101

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization ($000)	2021 Volume (TJ)	Rider ($/GJ)
Rate 1/1B/1U/1X		79,332.3	0.087
Rate 2/2B/2U/2X		28,937.2	0.087
Rate 3/3B/3U/3X		26,203.9	0.087
Rate 23		4,877.8	0.087
	12,101	139,351.2	0.087

The differences that result from the actual 2020 ending RSAM balance varying from the projection, and the actual 2021 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2022 RSAM Rate Riders and, in this way, refunded to or collected from customers.

10.2.3 Clean Growth Innovation Fund (CGIF)

The collection of the $0.40 per month innovation rider commenced on August 1, 2020 and is projected to collect $2.1 million in 2020 and forecast to collect $5.1 million in 2021. The shortened timeframe for portfolio approvals in 2020 will result in lower CGIF expenditures in 2020 at an estimated $1.5 million. Expenditures for 2021 are forecast to be $5.0 million.

The governance processes that will help maximize the potential of the CGIF are being established. The FEI steering teams that will review and approve portfolios are in place and the recruitment of members for the External Advisory Council is underway. Approval of the first CGIF expenditure portfolio is expected in the fall of 2020.

FEI is considering various initiatives for the first CGIF portfolio, including:

- A project with the UBC School of Engineering and another partner, with the goal to develop a novel scalable and automated hydrogen-enriched natural gas (HENG) laboratory setup for conducting an integrated experimental study on the performance and feasibility of HENG - from injection, mixing quality, material exposure, separation and combustion, to emission;
- A feasibility and pilot study of a coupled anaerobic digester and pyrolyzer for co-processing organic waste to renewable natural gas and biochar (a charcoal-like carbon-rich solid);
- Several proposals that would create blue or green hydrogen: a catalytic converter to turn bioethanol into green hydrogen; a proton exchange membrane electrolyser; a process using electrochemistry to split mineral salt and water to generate hydrogen and hydroxide; a continuous reactor to convert waste polyethylene to hydrogen and carbon black using sulphur; and two pyrolysis-based initiatives that would generate hydrogen and carbon black from methane;
- Several initiatives related to carbon capture, including a tandem carbon recycling system for carbon capture and utilization from exhaust flue gas stream, a modular decarbonization system using membrane contractors, and a system that uses flue gas to cultivate microalgae in photobioreactors for capture and utilization; and
- Proposals that would create syngas from woody biomass, displacing the use of natural gas at lime kilns.

More details on the portfolio will be available for the Annual Review for 2022 Delivery Rates and a CGIF reporting framework will be presented at that time.

10.3 *SUMMARY*

FEI has updated all of the 2021 delivery rate riders for 2020 Projected ending balances and 2021 Forecast volumes. As discussed above, FEI has not forecast any earnings sharing in 2020 to be included in 2021 delivery rates. FEI has also provided details on the CGIF, which is funded through the collection of the innovation rider.

11. 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 - 2020
FOR THE YEAR ENDING DECEMBER 31, 2020
($millions)

Schedule 1

Line No.	Particulars	2020 Projection		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (5.173)		
3	Change in Other Revenue	7.296	$ 2.123	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	32.777		
7	Capitalized Overhead Change	(16.568)	16.209	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation Rate Change (Depreciation Study)	(11.904)		
11	Depreciation from Net Additions	2.011	(9.893)	
12				
13	**AMORTIZATION EXPENSE**			
14	CIAC Amortization Rate Change (Depreciation Study)	0.674		
15	CIAC from Net Additions	0.010		
16	Net Salvage Rate Change (Depreciation Study)	12.617		
17	Deferrals	(1.947)	11.354	
18				
19	**FINANCING AND RETURN ON EQUITY**			
20	Financing Rate Changes	(11.004)		
21	Financing Ratio Changes	(0.973)		
22	Resetting Rate Base (PBR Plant True-up to Actual)	7.614		
23	Rate Base Growth	27.936	23.573	
24				
25	**TAX EXPENSE**			
26	Property and Other Taxes	0.400		
27	Other Income Taxes Changes	(17.128)	(16.728)	
28				
29	**Deferred 2020 Revenue Deficiency**		(10.338)	
30				
31	**REVENUE DEFICIENCY (SURPLUS)**		**$ 16.300**	Schedule 16, Line 11, Column 4
32				
33	Non-Bypass Margin at Existing Rates		813.968	Schedule 19, Line 17, Column 3
34	Rate Change		2.00%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 2

Line No.	Particulars	2019 Approved	2020 Projection at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 6,193,927	$ 6,924,038	$ 730,111	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	64,049	126,088	62,039	Schedule 6.2, Line 35, Column 4
3	Net Additions	708,717	515,511	(193,206)	Schedule 6.2, Line 35, Column 5+6+7
4	Plant in Service, Ending	6,966,693	7,565,637	598,944	
5					
6	Accumulated Depreciation Beginning	$ (2,066,879)	$ (2,197,878)	$ (130,999)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(155,720)	(86,965)	68,755	Schedule 7.2, Line 35, Column 7+8
9	Accumulated Depreciation Ending	(2,222,599)	(2,284,843)	(62,244)	
10					
11	CIAC, Beginning	$ (435,028)	$ (439,264)	$ (4,236)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	(2,705)	-	2,705	
13	Net Additions	(5,812)	(7,219)	(1,407)	Schedule 9, Line 6, Column 5+6
14	CIAC, Ending	(443,545)	(446,483)	(2,938)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 162,663	$ 170,507	$ 7,844	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	9,028	8,344	(684)	Schedule 9, Line 13, Column 5+6
19	Accumulated Amortization Ending - CIAC	171,691	178,851	7,160	
20					
21	Net Plant in Service, Mid-Year	$ 4,194,134	$ 4,798,327	$ 604,193	
22					
23	Adjustment for timing of Capital additions	$ 269,916	$ 159,575	$ (110,341)	
24	Capital Work in Progress, No AFUDC	43,820	36,412	(7,408)	
25	Unamortized Deferred Charges	(46,662)	(428)	46,234	Schedule 11.1, Line 26, Column 10
26	Working Capital	35,933	53,247	17,314	Schedule 13, Line 15, Column 3
27	Deferred Income Taxes Regulatory Asset	465,348	563,888	98,540	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(465,348)	(563,888)	(98,540)	Schedule 15, Line 6, Column 3
29	LILO Benefit	(195)	(104)	91	
30					
31	Mid-Year Utility Rate Base	$ 4,496,946	$ 5,047,029	$ 550,083	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	Reference	2020	Cross Reference
	(1)	(2)	(3)	(4)
1	**Formula Cost Drivers**			
2	CPI		2.692%	
3	AWE		2.881%	
4	Labour Split			
5	Non Labour		48.000%	
6	Labour		52.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.790%	
8	Productivity Factor	G-165-20	-0.500%	
9	Net Inflation Factor	Line 7 + Line 8	2.290%	
10				
11				
12	**Growth in Average Customer Calculation**			
13	Average Customer - Prior Year		1,031,862	
14	Average Customer Forecast - Test Year	Schedule 19, Line 30, Column 9	1,043,259	
15	Average Customer Change	Line 14 - Line 13	11,397	
16	Customer Growth Factor Multiplier	G-165-20	75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16	8,548	
18				
19	**Average Customer Continuity for Rate Setting Purposes**			
20	Average Customer Forecast - Prior Year	Line 13	1,031,862	
21	Change in Customers - Rate Setting Purposes	Line 17	8,548	
22	Average Customer Forecast - Rate Setting Purposes	Line 20 + Line 21	1,040,410	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2020
($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	2019 Unit Cost Growth Capital	$ 3,704				
3	2020 Net Inflation Factor	2.290%				Schedule 3, Line 9, Column 3
4	2020 Unit Cost Growth Capital	$ 3,789				
5	2020 Gross Customer Additions	18,000				
6	2020 Inflation Indexed Growth Capital	$ 68,199			$ 68,199	
7	2020 Growth CIAC				2,452	
8	2020 Inflation Indexed Gross Growth Capital				$ 70,651	
9						
10	**Capital Tracked Outside of Formula**					
11	Pension & OPEB (Growth Capital Portion)			$ 1,519		
12	Biomethane Upgraders			2,890		
13	Biomethane Interconnect			1,910		
14	NGT Assets			4,079		
15	Sustainment Capital			111,530		
16	Other Capital			49,770		
17	Sub-total			$ 171,698	171,698	
18						
19	**Total Capital Expenditures Before CIAC**				$ 242,349	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION Schedule 5
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars		2020 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	70,651	Schedule 4, Line 8
3	Forecast Capital Expenditures		171,698	Schedule 4, Line 17
4	Total Capital Expenditures	$	242,349	
5				
6	**Special Projects and CPCN's**			
7	LMIPSU	$	28,630	
8	IGU		45,846	
9	Tilbury Expansion Project		8,062	
10	Total Capital Expenditures	$	82,538	
11				
12	**Total Capital Expenditures**	$	324,887	
13				
14				
15	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
16				
17	Regular Capital Expenditures	$	242,349	Line 4
18	Add - Capitalized Overheads		50,306	Schedule 20, Line 23
19	Add - AFUDC		3,648	
20	Gross Capital Expenditures		296,303	
21	Change in Work in Progress		(3,880)	
22	**Total Regular Additions to Plant**	$	292,423	
23				
24	Special Projects and CPCN's Capital Expenditures	$	82,538	Line 10
25	Add - AFUDC		2,930	
26	Gross Capital Expenditures		85,468	
27	Change in Work in Progress		242,427	
28	**Total Special Projects and CPCN Additions to Plant**	$	327,895	
29				
30	**Grand Total Additions to Plant**	$	620,318	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	12/31/2019	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 107	$ 2	$ -	$ -	$ -	$ 109	
3	175-00	Unamortized Conversion Expense - Squamish	763	14	-	-	-	777	
4	178-00	Organization Expense	715	13	-	-	-	728	
5	401-01	Franchise and Consents	292	5	-	-	-	297	
6	402-11	Utility Plant Acquisition Adjustment	61	1	-	-	-	62	
7	402-03	Other Intangible Plant	1,873	34	-	-	-	1,907	
8	440-02	Water/Land Rights Tilbury	4,222	77	-	-	-	4,299	
9	461-01	Transmission Land Rights	50,316	916	-	-	-	51,232	
10	461-02	Transmission Land Rights - Mt. Hayes	598	11	-	-	-	609	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
13	471-01	Distribution Land Rights	3,158	57	252	-	-	3,467	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	112,850	2,055	-	9,623	(56,262)	68,266	
16	402-02	Application Software - 20%	19,617	357	-	9,396	(2,909)	26,461	
17			$ 194,613	$ 3,542	$ 252	$ 19,019	$ (59,171)	$ 158,255	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 30	$ 1	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,178	21	-	-	-	1,199	
22	433-00	Manufact'd Gas - Equipment	599	11	-	-	-	610	
23	434-00	Manufact'd Gas - Gas Holders	2,902	53	-	-	-	2,955	
24	436-00	Manufact'd Gas - Compressor Equipment	360	7	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,683	31	-	-	-	1,714	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	14,893	271	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	95,993	1,748	-	-	-	97,741	
28	443-00	Gas Holders - Storage (Tilbury)	176,338	3,211	14,735	-	-	194,284	
29	448-11	Piping (Tilbury)	38,335	698	8,746	-	-	47,779	
30	448-21	Pre-treatment (Tilbury)	31,963	582	-	-	-	32,545	
31	448-31	Liquefaction Equipment (Tilbury)	84,738	1,543	-	-	-	86,281	
32	449-00	Local Storage Equipment (Tilbury)	27,364	498	-	-	-	27,862	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,064	19	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	18,704	341	-	-	-	19,045	
35	443-05	Gas Holders - Storage (Mount Hayes)	60,669	1,105	-	-	-	61,774	
36	448-41	Send out Equipment(Tilbury)	6,673	122	-	-	-	6,795	
37	448-51	Sub-station and Electric (Tilbury)	35,568	648	-	-	-	36,216	
38	448-61	Control Room (Tilbury)	3,593	65	-	-	-	3,658	
39	448-10	Piping (Mount Hayes)	12,232	223	-	-	-	12,455	
40	448-20	Pre-treatment (Mount Hayes)	28,715	523	-	-	-	29,238	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,363	517	-	-	-	28,880	
42	448-40	Send out Equipment (Mount Hayes)	23,131	421	-	-	-	23,552	
43	448-50	Sub-station and Electric (Mount Hayes)	21,398	390	-	-	-	21,788	
44	448-60	Control Room (Mount Hayes)	6,310	115	-	-	-	6,425	
45	448-65	MH Inspection (Mount Hayes)	1,636	30	-	-	-	1,666	
46	449-01	Local Storage Equipment (Mount Hayes)	5,625	102	-	-	-	5,727	
47			$ 730,057	$ 13,296	$ 23,481	$ -	$ -	$ 766,834	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2019	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,612	$ 193	$ -	$ -	$ -	$ 10,805	
3	461-00	Transmission Land Rights	-	-	-	-	-	-	
4	462-00	Compressor Structures	32,272	588	-	2,243	(351)	34,752	
5	463-00	Measuring Structures	19,849	361	-	-	-	20,210	
6	464-00	Other Structures & Improvements	6,753	123	-	1,872	(3)	8,745	
7	465-00	Mains	1,395,634	25,414	-	22,514	(2,023)	1,441,539	
8	465-20	Mains - INSPECTION	38,427	700	-	10,487	(8,357)	41,257	
9	465-11	IP Transmission Pipeline - Whistler	57,639	1,050	-	-	-	58,689	
10	465-30	Mt Hayes - Mains	6,194	113	-	-	-	6,307	
11	465-10	Mains - Byron Creek	1,346	25	-	-	-	1,371	
12	466-00	Compressor Equipment	191,393	3,485	-	3,616	(902)	197,592	
13	466-10	Compressor Equipment - OVERHAUL	8,041	146	-	4	-	8,191	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,244	96	-	958	-	6,298	
15	467-10	Measuring & Regulating Equipment	77,897	1,419	-	7,924	(303)	86,937	
16	467-20	Telemetering	17,962	327	-	-	-	18,289	
17	467-31	IP Intermediate Pressure Whistler	307	6	-	30	-	343	
18	467-30	Measuring & Regulating Equipment - Byron Creek	286	5	-	-	-	291	
19	468-00	Communication Structures & Equipment	3,840	70	-	3,096	-	7,006	
20			$ 1,873,696	$ 34,121	$ -	$ 52,744	$ (11,939)	$ 1,948,622	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 5,359	$ 98	$ -	$ -	$ -	$ 5,457	
24	472-00	Structures & Improvements	33,811	616	12,328	1,807	(61)	48,501	
25	472-10	Structures & Improvements - Byron Creek	122	2	-	-	-	124	
26	473-00	Services	1,268,923	23,107	6	71,410	(3,837)	1,359,609	
27	474-00	House Regulators & Meter Installations	173,566	3,161	-	-	(6,183)	170,544	
28	474-02	Meters/Regulators Installations	169,208	3,081	-	21,255	-	193,544	
29	475-00	Mains	1,583,603	28,838	265,952	58,006	(3,468)	1,932,931	
30	476-00	Compressor Equipment	603	11	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	159,028	2,896	23,359	13,730	(789)	198,224	
32	477-20	Telemetering	18,069	329	2,517	770	(45)	21,640	
33	477-30	Measuring & Regulating Equipment - Byron Creek	150	3	-	-	-	153	
34	478-10	Meters	276,342	5,032	-	17,167	(5,189)	293,352	
35	478-20	Instruments	13,754	250	-	707	-	14,711	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 3,702,538	$ 67,424	$ 304,162	$ 184,852	$ (19,572)	$ 4,239,404	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 697	$ 13	$ -	$ -	$ -	$ 710	
41	475-10	Bio Gas Mains – Municipal Land	1,572	29	-	-	-	1,601	
42	475-20	Bio Gas Mains – Private Land	54	1	-	-	-	55	
43	418-10	Bio Gas Purification Overhaul	20	-	-	-	-	20	
44	418-20	Bio Gas Purification Upgrader	9,872	180	-	940	-	10,992	
45	477-40	Bio Gas Reg & Meter Equipment	2,702	49	-	-	-	2,751	
46	478-30	Bio Gas Meters	35	1	-	-	-	36	
47	474-10	Bio Gas Reg & Meter Installations	222	4	-	-	-	226	
48	483-25	RNG Comp S/W	136	2	-	-	-	138	
49			$ 15,310	$ 279	$ -	$ 940	$ -	$ 16,529	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.2
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	12/31/2019	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 14,570	$ 265	$ -	$ 4,357	$ -	$ 19,192	
3	476-20	NG Transportation LNG Dispensing Equipment	13,086	238	-	(201)	-	13,123	
4	476-30	NG Transportation CNG Foundations	2,739	50	-	-	-	2,789	
5	476-40	NG Transportation LNG Foundations	1,288	23	-	-	-	1,311	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,467	27	-	-	-	1,494	
7	476-60	NG Transportation CNG Dehydrator	544	10	-	-	-	554	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 33,694	$ 613	$ -	$ 4,156	$ -	$ 38,463	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 30,746	$ 560	$ -	$ -	$ -	$ 31,306	
13	482-10	Frame Buildings	24,217	441	-	-	-	24,658	
14	482-20	Masonry Buildings	118,244	2,153	-	3,152	(81)	123,468	
15	482-30	Leasehold Improvement	5,689	104	-	-	(22)	5,771	
16	483-30	GP Office Equipment	2,698	49	-	412	(240)	2,919	
17	483-40	GP Furniture	18,594	339	-	3,144	(5,012)	17,065	
18	483-10	GP Computer Hardware	36,568	666	-	9,426	(4,351)	42,309	
19	483-20	GP Computer Software	7,305	133	-	-	(1,082)	6,356	
20	484-00	Vehicles	35,237	642	-	8,074	-	43,953	
21	484-10	Vehicles - Leased	18,009	328	-	-	(1,458)	16,879	
22	485-10	Heavy Work Equipment	737	13	-	-	-	750	
23	485-20	Heavy Mobile Equipment	9,111	166	-	-	-	9,277	
24	486-00	Small Tools & Equipment	49,407	900	-	4,901	(991)	54,217	
25	487-20	Equipment on Customer's Premises	3	-	-	-	-	3	
26	488-10	Telephone	2,602	47	-	-	(518)	2,131	
27	488-20	Radio	14,963	272	-	1,603	(370)	16,468	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 374,130	$ 6,813	$ -	$ 30,712	$ (14,125)	$ 397,530	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 6,924,038	$ 126,088	$ 327,895	$ 292,423	$ (104,807)	$ 7,565,637	
36									
37		Cross Reference			Schedule 5, Line 28, Column 2	Schedule 5, Line 22, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2019	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 63	$ -	$ 1	$ -	$ -	$ -	$ 64	
3	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	777	-	-	-	-	-	777	
4	178-00	Organization Expense	728	1.00%	443	-	7	-	-	-	450	
5	401-01	Franchise and Consents	297	1.08%	234	-	11	-	-	-	245	
6	402-11	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	-	62	
7	402-03	Other Intangible Plant	1,907	2.50%	1,150	-	48	-	-	-	1,198	
8	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	51,232	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	609	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
13	471-01	Distribution Land Rights	3,467	0.00%	248	-	-	-	-	-	248	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	114,905	12.50%	79,283	-	8,171	(56,262)	-	-	31,192	
16	402-02	Application Software - 20%	19,974	20.00%	7,208	-	3,995	(2,909)	-	-	8,294	
17			$ 198,407		$ 91,254	$ -	$ 12,233	$ (59,171)	$ -	$ -	$ 44,316	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	2.50%	365	-	30	-	-	-	395	
22	433-00	Manufact'd Gas - Equipment	610	5.00%	284	-	30	-	-	-	314	
23	434-00	Manufact'd Gas - Gas Holders	2,955	2.50%	730	-	74	-	-	-	804	
24	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	154	-	15	-	-	-	169	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	5.00%	1,073	-	86	-	-	-	1,159	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	97,741	2.20%	6,751	-	2,150	-	-	-	8,901	
28	443-00	Gas Holders - Storage (Tilbury)	194,284	1.23%	15,965	-	2,390	-	-	-	18,355	
29	448-11	Piping (Tilbury)	47,779	2.45%	951	-	956	-	-	-	1,907	
30	448-21	Pre-treatment (Tilbury)	32,545	3.84%	1,221	-	1,250	-	-	-	2,471	
31	448-31	Liquefaction Equipment (Tilbury)	86,281	2.45%	2,086	-	2,114	-	-	-	4,200	
32	449-00	Local Storage Equipment (Tilbury)	27,862	2.77%	18,178	-	772	-	-	-	18,950	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	3.85%	6,095	-	733	-	-	-	6,828	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	1.65%	8,599	-	1,019	-	-	-	9,618	
36	448-41	Send out Equipment(Tilbury)	6,795	2.41%	161	-	164	-	-	-	325	
37	448-51	Sub-station and Electric (Tilbury)	36,216	2.41%	873	-	873	-	-	-	1,746	
38	448-61	Control Room (Tilbury)	3,658	6.09%	228	-	223	-	-	-	451	
39	448-10	Piping (Mount Hayes)	12,455	2.45%	2,500	-	305	-	-	-	2,805	
40	448-20	Pre-treatment (Mount Hayes)	29,238	3.84%	9,823	-	1,123	-	-	-	10,946	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	2.45%	6,139	-	708	-	-	-	6,847	
42	448-40	Send out Equipment (Mount Hayes)	23,552	2.41%	4,931	-	568	-	-	-	5,499	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.41%	4,616	-	525	-	-	-	5,141	
44	448-60	Control Room (Mount Hayes)	6,425	6.09%	3,414	-	391	-	-	-	3,805	
45	448-65	MH Inspection (Mount Hayes)	1,666	20.00%	1,005	-	333	-	-	-	1,338	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	3.08%	643	-	176	-	-	-	819	
47			$ 766,834		$ 96,786	$ -	$ 17,008	$ -	$ -	$ -	$ 113,794	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2019	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,805	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	-	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	32,860	3.32%	18,955	-	1,091	(351)	-	-	19,695	
5	463-00	Measuring Structures	20,210	2.13%	7,803	-	430	-	-	-	8,233	
6	464-00	Other Structures & Improvements	6,876	3.62%	3,394	-	249	(3)	-	-	3,640	
7	465-00	Mains	1,421,048	1.46%	434,110	-	20,747	(2,023)	-	-	452,834	
8	465-20	Mains - INSPECTION	39,127	15.20%	19,624	-	5,954	(8,357)	-	-	17,221	
9	465-11	IP Transmission Pipeline - Whistler	58,689	1.54%	6,431	-	904	-	-	-	7,335	
10	465-30	Mt Hayes - Mains	6,307	1.54%	884	-	97	-	-	-	981	
11	465-10	Mains - Byron Creek	1,371	5.03%	1,428	-	69	-	-	-	1,497	
12	466-00	Compressor Equipment	194,878	2.42%	98,711	-	4,716	(902)	-	-	102,525	
13	466-10	Compressor Equipment - OVERHAUL	8,187	10.19%	3,226	-	985	-	-	-	4,211	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,340	2.34%	1,589	-	125	-	-	-	1,714	
15	467-10	Measuring & Regulating Equipment	79,316	2.12%	27,851	-	1,681	(303)	-	-	29,229	
16	467-20	Telemetering	18,289	8.97%	11,589	-	1,640	-	-	-	13,229	
17	467-31	IP Intermediate Pressure Whistler	313	2.26%	113	-	7	-	-	-	120	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	31	-	7	-	-	-	38	
19	468-00	Communication Structures & Equipment	3,910	0.00%	4,393	-	-	-	-	-	4,393	
20			$ 1,907,817		$ 640,635	$ -	$ 38,702	$ (11,939)	$ -	$ -	$ 667,398	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
24	472-00	Structures & Improvements	46,755	2.15%	10,227	-	1,005	(61)	-	-	11,171	
25	472-10	Structures & Improvements - Byron Creek	124	4.67%	71	-	6	-	-	-	77	
26	473-00	Services	1,292,036	2.18%	340,851	-	28,166	(3,837)	-	-	365,180	
27	474-00	House Regulators & Meter Installations	176,727	7.45%	93,023	-	13,166	(6,183)	-	-	100,006	
28	474-02	Meters/Regulators Installations	172,289	4.55%	28,781	-	7,839	-	-	-	36,620	
29	475-00	Mains	1,878,393	1.35%	518,495	-	25,357	(3,468)	-	-	540,384	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	185,283	2.51%	57,931	-	4,651	(789)	-	-	61,793	
32	477-20	Telemetering	20,915	3.59%	6,201	-	751	(45)	-	-	6,907	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	281,374	6.06%	159,365	-	17,051	(5,189)	-	-	171,227	
35	478-20	Instruments	14,004	2.92%	6,834	-	409	-	-	-	7,243	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 4,074,124		$ 1,223,420	$ -	$ 98,401	$ (19,572)	$ -	$ -	$ 1,302,249	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 710	2.69%	$ 109	$ -	$ 19	$ -	$ -	$ -	$ 128	
41	475-10	Bio Gas Mains – Municipal Land	1,601	1.56%	118	-	25	-	-	-	143	
42	475-20	Bio Gas Mains – Private Land	55	1.56%	7	-	1	-	-	-	8	
43	418-10	Bio Gas Purification Overhaul	20	5.00%	6	-	1	-	-	-	7	
44	418-20	Bio Gas Purification Upgrader	10,052	5.00%	2,339	-	503	-	-	-	2,842	
45	477-40	Bio Gas Reg & Meter Equipment	2,751	3.22%	444	-	89	-	-	-	533	
46	478-30	Bio Gas Meters	36	4.89%	12	-	2	-	-	-	14	
47	474-10	Bio Gas Reg & Meter Installations	226	5.32%	53	-	12	-	-	-	65	
48	483-25	RNG Comp S/W	138	20.00%	83	-	28	-	-	-	111	
49			$ 15,589		$ 3,171	$ -	$ 680	$ -	$ -	$ -	$ 3,851	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2019	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2020	Cross Reference
	(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	14,835	5.00%	3,151	-	742	-	-	-	$ 3,893	
3	476-20	NG Transportation LNG Dispensing Equipment	13,324	5.00%	2,904	-	666	-	-	-	3,570	
4	476-30	NG Transportation CNG Foundations	2,789	5.00%	520	-	139	-	-	-	659	
5	476-40	NG Transportation LNG Foundations	1,311	5.00%	362	-	66	-	-	-	428	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,494	10.00%	618	-	149	-	-	-	767	
7	476-60	NG Transportation CNG Dehydrator	554	5.00%	126	-	28	-	-	-	154	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 34,307		$ 7,681	$ -	$ 1,790	$ -	$ -	$ -	$ 9,471	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 31,306	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	24,658	3.17%	11,762	-	782	-	-	-	12,544	
14	482-20	Masonry Buildings	120,397	1.52%	31,366	-	1,830	(81)	-	-	33,115	
15	482-30	Leasehold Improvement	5,793	9.49%	3,981	-	596	(22)	-	-	4,555	
16	483-30	GP Office Equipment	2,747	6.67%	1,404	-	183	(240)	-	-	1,347	
17	483-40	GP Furniture	18,933	5.00%	9,733	-	947	(5,012)	-	-	5,668	
18	483-10	GP Computer Hardware	37,234	25.00%	11,584	-	9,091	(4,351)	-	-	16,324	
19	483-20	GP Computer Software	7,438	12.50%	3,568	-	818	(1,082)	-	-	3,304	
20	484-00	Vehicles	35,879	11.07%	11,432	-	3,972	-	-	-	15,404	
21	484-10	Vehicles - Leased	18,337	9.44%	17,314	-	484	(1,458)	-	-	16,340	
22	485-10	Heavy Work Equipment	750	5.14%	410	-	39	-	-	-	449	
23	485-20	Heavy Mobile Equipment	9,277	6.09%	3,588	-	565	-	-	-	4,153	
24	486-00	Small Tools & Equipment	50,307	5.00%	22,338	-	2,489	(991)	-	-	23,836	
25	487-20	Equipment on Customer's Premises	3	6.67%	3	-	-	-	-	-	3	
26	488-10	Telephone	2,649	6.67%	2,099	-	158	(518)	-	-	1,739	
27	488-20	Radio	15,235	6.67%	4,332	-	1,004	(370)	-	-	4,966	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 380,943		$ 134,931	$ -	$ 22,958	$ (14,125)	$ -	$ -	$ 143,764	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 7,378,021		$ 2,197,878	$ -	$ 191,772	$ (104,807)	$ -	$ -	$ 2,284,843	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(680)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(1,649)					
38		**Net Depreciation Expense**					$ 189,443					
39												
40		Cross Reference	Schedule 6.2, Line 35, Column 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 8

Line No.	Particulars			12/31/2019	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2020	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										

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2019	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2020	Cross Reference
9	**NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**									
10	**FOR THE YEAR ENDING DECEMBER 31, 2020**									
11	**($000s)**									
12										
13										
14–15	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2019	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2020	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%	129,938	-	4,238	-	-	134,176	
21									-	
22	**Total**	$ 177,648		$ 129,938	$ -	$ 4,238	$ -	$ -	$ 134,176	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 9

Line No.	Particulars	12/31/2019	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 288,570	$ -	$ -	$ 2,452	$ -	$ 291,022	
3	Transmission Contributions	149,134	-	-	3,362	-	152,496	
4	Others	994	-	-	1,405	-	2,399	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 439,264	$ -	$ -	$ 7,219	$ -	$ 446,483	
7								
8	**Amortization**							
9	Distribution Contributions	$ (115,095)	$ -	$ -	$ (6,089)	$ -	$ (121,184)	
10	Transmission Contributions	(54,376)	-	-	(2,177)	-	(56,553)	
11	Others	(820)	-	-	(50)	-	(870)	
12	Biomethane	(216)	-	-	(28)	-	(244)	
13	**Total**	$ (170,507)	$ -	$ -	$ (8,344)	$ -	$ (178,851)	
14								
15	**Net CIAC**	$ 268,757	$ -	$ -	$ (1,125)	$ -	$ 267,632	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (8,344)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,316)			

NET SALVAGE CONTINUITY SCHEDULE Schedule 10
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2019	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**MANUFACTURED GAS / LOCAL STORAGE**							
2	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 1,714	0.00%	$ (22)	$ -	$ -	$ (22)	
3	442-00	Structures & Improvements (Tilbury)	97,741	0.68%	849	665	-	1,514	
4	443-00	Gas Holders - Storage (Tilbury)	194,284	1.12%	1,183	2,176	-	3,359	
5	448-11	Piping (Tilbury)	47,779	0.28%	328	109	-	437	
6	448-21	Pre-treatment (Tilbury)	32,545	0.50%	430	163	-	593	
7	448-31	Liquefaction Equipment (Tilbury)	86,281	0.57%	1,361	492	-	1,853	
8	449-00	Local Storage Equipment (Tilbury)	27,862	0.82%	893	228	-	1,121	
9	442-01	Structures & Improvements (Mount Hayes)	19,045	0.49%	234	93	-	327	
10	443-05	Gas Holders - Storage (Mount Hayes)	61,774	0.36%	631	222	-	853	
11	448-41	Send out Equipment(Tilbury)	6,795	0.28%	25	19	-	44	
12	448-51	Sub-station and Electric (Tilbury)	36,216	0.56%	454	203	-	657	
13	448-10	Piping (Mount Hayes)	12,455	0.28%	93	35	-	128	
14	448-20	Pre-treatment (Mount Hayes)	29,238	0.50%	396	146	-	542	
15	448-30	Liquefaction Equipment (Mount Hayes)	28,880	0.57%	465	165	-	630	
16	448-40	Send out Equipment (Mount Hayes)	23,552	0.28%	186	66	-	252	
17	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.56%	351	122	-	473	
18	449-01	Local Storage Equipment (Mount Hayes)	5,727	0.32%	53	18	-	71	
19			$ 733,676		$ 7,910	$ 4,922	$ -	$ 12,832	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 10.1

	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2019	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 32,860	0.11%	$ 448	$ 36	$ -	$ 484	
3	463-00	Measuring Structures	20,210	0.62%	380	126	-	506	
4	464-00	Other Structures & Improvements	6,876	0.29%	73	19	-	92	
5	465-00	Mains	1,421,048	0.42%	20,527	5,969	-	26,496	
6	465-11	IP Transmission Pipeline - Whistler	58,689	0.34%	431	200	-	631	
7	465-30	Mt Hayes - Mains	6,307	0.30%	60	19	-	79	
8	466-00	Compressor Equipment	194,878	0.07%	2,183	136	-	2,319	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,340	0.21%	34	11	-	45	
10	467-10	Measuring & Regulating Equipment	79,316	0.16%	745	127	-	872	
11	467-20	Telemetering	18,289	0.00%	(26)	-	-	(26)	
12	467-31	IP Intermediate Pressure Whistler	313	0.35%	2	1	-	3	
13	468-00	Communication Structures & Equipment	3,910	0.00%	401	-	-	401	
14			$ 1,848,036		$ 25,258	$ 6,644	$ -	$ 31,902	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (1,393)	$ -	$ -	$ (1,393)	
18	472-00	Structures & Improvements	46,755	0.52%	76	243	-	319	
19	473-00	Services	1,292,036	2.09%	40,112	27,004	(15,558)	51,558	
20	474-00	House Regulators & Meter Installations	176,727	3.37%	(8,008)	5,956	-	(2,052)	
21	474-02	Meters/Regulators Installations	172,289	0.00%	748	-	-	748	
22	475-00	Mains	1,878,393	0.50%	33,102	9,392	-	42,494	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	185,283	0.45%	2,890	846	-	3,736	
24	477-20	Telemetering	20,915	0.48%	9	100	-	109	
24	478-10	Meters	281,374	0.00%	2,874	-	-	2,874	
24			$ 4,059,843		$ 71,116	$ 43,541	$ (15,558)	$ 99,099	
24									
25		**BIO GAS**							
25	472-20	Bio Gas Struct. & Improvements	$ 710	0.29%	$ 6	$ 2	$ -	$ 8	
25	475-10	Bio Gas Mains – Municipal Land	1,601	0.39%	30	6	-	36	
25	475-20	Bio Gas Mains – Private Land	55	0.39%	1	-	-	1	
27	418-20	Bio Gas Purification Upgrader	10,052	0.24%	70	25	-	95	
29	474-10	Bio Gas Reg & Meter Installations	226	1.44%	10	3	-	13	
31			$ 12,644		$ 117	$ 36	$ -	$ 153	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 10.2

	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2019	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 14,835	0.00%	$ (1)	$ -	$ -	$ (1)	
3			$ 14,835		$ (1)	$ -	$ -	$ (1)	
4									
5		**GENERAL PLANT & EQUIPMENT**							
6	482-10	Frame Buildings	$ 24,658	0.37%	$ (371)	$ 91	$ -	$ (280)	
7	482-20	Masonry Buildings	120,397	0.08%	921	96	-	1,017	
8	482-30	Leasehold Improvement	5,793	0.00%	(46)	-	-	(46)	
9	483-30	GP Office Equipment	2,747	0.00%	1	-	-	1	
10	483-40	GP Furniture	18,933	0.00%	(67)	-	-	(67)	
11	484-00	Vehicles	35,879	-3.70%	1,031	(1,328)	-	(297)	
12	485-10	Heavy Work Equipment	750	-0.67%	(11)	(5)	-	(16)	
13	485-20	Heavy Mobile Equipment	9,277	-1.80%	(508)	(167)	-	(675)	
14	486-00	Small Tools & Equipment	50,307	0.00%	36	-	-	36	
15	487-20	Equipment on Customer's Premises	3	0.00%	(2)	-	-	(2)	
16	488-20	Radio	15,235	0.00%	(7)	-	-	(7)	
17			$ 283,979		$ 977	$ (1,313)	$ -	$ (336)	
18									
19		**Total**	$ 6,953,013		$ 105,377	$ 53,830	$ (15,558)	$ 143,649	
20		Less: Depreciation & Amortization Transferred to Biomethane BVA				(36)			
21		**Net Salvage Depreciation Expense**				$ 53,794			
22		Cross Reference	Schedule 6.2, Column 3+4+5						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/2019	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2020	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (14,711)	$ -	$ 11,189	$ (3,021)	$ -	$ 10,076	$ (2,721)	$ 812	$ (6,950)	
3	Commodity Cost Reconciliation Account (CCRA)	(11,116)	-	18,223	(4,920)	-	-	-	2,187	(4,465)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	26,353	-	(982)	265	-	(10,908)	2,945	17,673	22,013	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(5,820)	-	240	(65)	93	(3)	1	(5,554)	(5,687)	
6	Revelstoke Propane Cost Deferral Account	298	-	(229)	62	-	-	-	131	215	
7	SCP Mitigation Revenues Variance Account	2,784	-	-	-	(1,430)	-	-	1,354	2,069	
8	Pension & OPEB Variance	(4,893)	-	-	-	1,717	-	-	(3,176)	(4,035)	
9	BCUC Levies Variance	1,925	-	-	-	(1,925)	-	-	-	963	
10	TESDA Overhead Allocation Variance	567	-	-	-	(567)	-	-	-	284	
11		$ (4,613)	$ -	$ 28,441	$ (7,679)	$ (2,112)	$ (835)	$ 225	$ 13,427	$ 4,407	
12	**2. Rate Smoothing Accounts**										
13											
14	**3. Benefits Matching Accounts**										
15	Demand-Side Management (DSM)	$ 137,957	$ 25,458	$ 29,928	$ (8,081)	$ (19,797)	$ -	$ -	$ 165,465	$ 164,440	
16	NGV Conversion Grants	32	-	-	-	(15)	-	-	17	25	
17	Emissions Regulations	(5,444)	-	-	-	1,433	-	-	(4,011)	(4,728)	
18	On-Bill Financing Pilot Program	2	-	-	-	-	-	-	2	2	
19	Greenhouse Gas Reduction Regulation Incentives	30,633	-	5,725	(1,546)	(4,563)	-	-	30,249	30,441	
20	CNG and LNG Recoveries	(536)	-	(603)	163	536	-	-	(440)	(488)	
21	2016 Cost of Capital Application	420	-	-	-	(420)	-	-	-	210	
22	BCUC Initiated Inquiry Costs	-	133	596	(161)	-	-	-	568	351	
23	2015-2019 Annual Review Costs	7	-	-	-	(7)	-	-	-	4	
24	2017 Rate Design Application	1,052	-	-	-	(263)	-	-	789	921	
25	2017 Long Term Resource Plan Application	465	-	-	-	(212)	-	-	253	359	
26	2019-2022 DSM Expenditures Application Costs	71	-	4	(1)	(24)	-	-	50	61	
27	City of Coquitlam Application Proceeding	-	189	126	(34)	-	-	-	281	235	
28		$ 164,659	$ 25,780	$ 35,776	$ (9,660)	$ (23,332)	$ -	$ -	$ 193,223	$ 191,833	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/2019	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2020	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 7,189	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 6,452	$ 6,821	
3	2010-2011 Customer Service O&M and COS	1,556	-	-	-	(1,556)	-	-	-	778	
4	Gas Asset Records Project	1,375	-	1,186	(320)	(650)	-	-	1,591	1,483	
5	BC OneCall Project	184	-	-	-	(121)	-	-	63	124	
6	Gains and Losses on Asset Disposition	16,457	-	-	-	(3,986)	-	-	12,471	14,464	
7	Net Salvage Provision/Cost	(105,377)	-	15,558	-	(53,830)	-	-	(143,649)	(124,513)	
8	PCEC Start Up Costs	700	-	-	-	(44)	-	-	656	678	
9	2022 Long Term Gas Resource Plan Application	-	-	295	(80)	-	-	-	215	108	
10	2020–2024 MRP Application	732	-	281	(76)	(146)	-	-	791	762	
11	City of Surrey Operating Terms Application Costs	245	-	-	-	(130)	-	-	115	180	
12	IGU Application and Preliminary Stage Development Costs	-	(1,168)	4	(1)	389	-	-	(776)	(972)	
13	Annual Review of 2020-2024 Rates	-	-	100	(27)	-	-	-	73	37	
14		$ (76,939)	$ (1,168)	$ 17,424	$ (504)	$ (60,811)	$ -	$ -	$ (121,998)	$ (100,050)	
15	**4. Retroactive Expense Accounts**										
16											
17	**5.Other Accounts**										
18	Pension & OPEB Funding	$ (238,423)	$ (64,497)	$ (12,549)	$ -	$ -	$ -	$ -	$ (315,469)	$ (309,195)	
19	US GAAP Pension & OPEB Funded Status	145,676	64,497	-	-	-	-	-	210,173	210,173	
20	BFI Costs and Recoveries	(539)	-	(81)	22	-	-	-	(598)	(569)	
21	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	
22	BVA Balance Transfer	2,467	-	-	-	-	(3,785)	1,022	(296)	1,086	
23	COVID-19 Customer Recovery Fund	-	-	4,569	(795)	-	-	-	3,774	1,887	
24		$ (90,819)	$ -	$ (8,061)	$ (773)	$ -	$ (3,785)	$ 1,022	$ (102,416)	$ (96,618)	
25											
26	**Total**	$ (7,712)	$ 24,612	$ 73,580	$ (18,616)	$ (86,255)	$ (4,620)	$ 1,247	$ (17,764)	$ (428)	
27	Less: Net Salvage Amortization Transferred to Biomethane BVA					36					
28	**Net Rate Base Deferred Amortization Expense**					$ (86,219)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 12

Line No.	Particulars	12/31/2019	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2020	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ 1	$ -	$ 4,700	$ (1,269)	$ -	$ -	$ -	$ 3,432	$ 1,717	
3	Flowthrough (2020-2024)	-	-	-	-	-	-	-	-	-	
4	Flowthrough (2014-2019)	(35,250)	-	(1,142)	-	36,392	-	-	-	(17,625)	
5	Marketer Cost Variance	1	-	26	(7)	-	-	-	20	11	
6		$ (35,248)	$ -	$ 3,584	$ (1,276)	$ 36,392	$ -	$ -	$ 3,452	$ (15,897)	
7	**2. Rate Smoothing Accounts**										
8	2017 & 2018 Revenue Surplus Account	$ (31,336)	$ -	$ 8,791	$ (2,791)	$ -	$ -	$ -	$ (25,336)	$ (28,336)	
9											
10	**3. Benefits Matching Accounts**										
11	Demand-Side Management (DSM) - Non Rate Base	$ 25,458	$ (25,458)	$ 40,722	$ (10,774)	$ -	$ -	$ -	$ 29,948	$ 14,974	
12	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
13	IGU Application and Preliminary Stage Development Costs	(1,168)	1,168	-	-	-	-	-	-	-	
14	Transmission Integrity Management Capabilities	12,343	-	7,734	(1,863)	-	-	-	18,214	15,279	
15	Clean Growth Innovation Fund	-	-	1,531	(405)	-	(2,090)	564	(400)	(200)	
16		$ 34,235	$ (24,290)	$ 49,987	$ (13,042)	$ -	$ (2,090)	$ 564	$ 45,364	$ 27,655	
17	**4. Retroactive Expense Accounts**										
18											
19	**5.Other Accounts**										
20	Mark to Market - Hedging Transactions	$ (1,621)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,621)	$ (1,621)	
21	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
22	2014-2019 Earning Sharing Account	1,173	-	31	2	(1,206)	-	-	-	587	
23	MRP Earnings Sharing Account	-	-	-	-	-	-	-	-	-	
24		$ (448)	$ -	$ 31	$ 2	$ (1,206)	$ -	$ -	$ (1,621)	$ (1,034)	
25											
26											
27	**Total Non Rate Base Deferral Accounts**	$ (32,797)	$ (24,290)	$ 62,393	$ (17,107)	$ 35,186	$ (2,090)	$ 564	$ 21,859	$ (17,612)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 13

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 17,537	$ 16,629	$ (908)	Schedule 14, Line 29, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	-	1,341	1,341	
6	Reserve For Bad Debts	(5,510)	-	5,510	Note 1
7	Employee Withholdings	(6,118)	(6,335)	(217)	
8					
9	**Other Working Capital Items**				
10	Transmission Line Pack Gas	89	1,724	1,635	
11	Gas In Storage	28,998	38,204	9,206	
12	Inventory - Materials and Supplied	1,514	2,005	491	
13	Refundable Contributions	(577)	(321)	256	
14					
15	Total	$ 35,933	$ 53,247	$ 17,314	
16					
17	Note 1: Reserve for bad debts included in Cash Working Capital calculation (Schedule 14) beginning in 2020.				

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 14

Line No.	Particulars	2020 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	$ 749,416	40.3	$ 30,201,465		
4	Commercial Tariff Revenue	396,349	37.8	14,981,992		
4	Industrial Tariff Revenue	127,125	47.7	6,063,840		
5	Bypass and Special Rates	42,558	37.6	1,600,181		
6						
7	**Other Revenue**					
8	Late Payment Charges	1,671	53.8	89,900		
9	Application Charges	1,965	39.0	76,635		
10	Other Utility Income	33,961	39.0	1,324,479		
11						
12	Total	$ 1,353,045		$ 54,338,492	40.2	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 449,818	(40.0)	$ (17,992,720)		
16	Operating and Maintenance	262,297	(31.8)	(8,341,045)		
17	Property Taxes	67,959	(1.3)	(88,346)		
18	Operating Fees	8,494	(352.9)	(2,997,557)		
19	Carbon Tax	304,059	(30.7)	(9,334,611)		
20	GST	11,365	(39.7)	(451,191)		
21	PST	5,395	(45.8)	(247,091)		
22	Income Tax	35,844	(15.2)	(544,829)		
23						
24	Total	$ 1,145,231		$ (39,997,390)	(34.9)	
25						
26	Net Lag (Lead) Days				5.3	
27	Total Expenses				$ 1,145,231	
28						
29	Cash Working Capital				$ 16,629	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 15

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (344,407)	$ (426,473)	$ (82,066)	
2	Tax Gross Up	(127,383)	(157,736)	(30,353)	
3	DIT Liability/Asset - End of Year	$ (471,790)	$ (584,209)	$ (112,419)	
4	DIT Liability/Asset - Opening Balance	(458,905)	(543,567)	(84,662)	
5					
6	DIT Liability/Asset - Mid Year	$ (465,348)	$ (563,888)	$ (98,540)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 16

Line No.	Particulars	2019 Approved	2020 Projection at Existing Rates	2020 Projection Revised Revenue	2020 Projection at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	137,849	153,071		153,071	15,222	
3	Transportation Volume (TJ)	97,535	82,323		82,323	(15,212)	
4		235,383	235,393	-	235,393	10	Schedule 17, Line 24, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,084,285	$ 1,205,929	$ -	$ 1,205,929	$ 121,644	
8	Deficiency (Surplus)	-		14,890	14,890	14,890	
9	Transportation	129,154	93,219	-	93,219	(35,935)	
10	Deficiency (Surplus)	-		1,410	1,410	1,410	
11	Total	1,213,439	1,299,148	16,300	1,315,448	102,009	Schedule 19, Line 30, Column 8
12				-			
13	**COST OF ENERGY**	369,282	449,818	-	449,818	80,536	Schedule 18, Line 24, Column 3
14							
15	**MARGIN**	844,157	849,330	16,300	865,630	21,473	
16							
17	**EXPENSES**						
18	O&M Expense (net)	246,088	262,297	-	262,297	16,209	Schedule 20, Line 24, Column 4
19	Depreciation & Amortization	230,699	232,160	-	232,160	1,461	Schedule 21, Line 15, Column 3
20	Property Taxes	67,559	67,959	-	67,959	400	Schedule 22, Line 8, Column 3
21	Other Revenue	(44,893)	(37,597)	-	(37,597)	7,296	Schedule 23, Line 12, Column 3
22	Deferred 2020 Revenue Deficiency	-	(10,338)	-	(10,338)	(10,338)	Schedule 1, Line 29, Column 3
23	Utility Income Before Income Taxes	344,704	334,849	16,300	351,149	6,445	
24							
25	Income Taxes	52,972	31,444	4,400	35,844	(17,128)	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 291,732	$ 303,405	$ 11,900	$ 315,305	$ 23,573	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 4,496,946	$ 5,046,648		$ 5,047,029	$ 550,083	Schedule 2, Line 31, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.49%	6.01%		6.25%	-0.24%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 17

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	80,768.4	81,063.9	295.5	
4	Commercial				
5	Rate Schedule 2	30,209.8	28,933.1	(1,276.7)	
6	Rate Schedule 3	21,546.4	25,274.7	3,728.3	
7	Rate Schedule 23	9,557.9	4,799.4	(4,758.5)	
8	Industrial				
9	Rate Schedule 4	141.3	145.1	3.8	
10	Rate Schedule 5	3,129.4	8,215.2	5,085.8	
11	Rate Schedule 6	41.0	21.3	(19.7)	
12	Rate Schedule 7	316.1	6,851.5	6,535.4	
13	Rate Schedule 22 - Firm Service	11,343.9	11,938.3	594.4	
14	Rate Schedule 22 - Interruptible Service	22,036.2	17,551.9	(4,484.3)	
15	Rate Schedule 25	14,594.9	9,742.8	(4,852.1)	
16	Rate Schedule 27	7,887.7	4,665.5	(3,222.2)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	9,819.3	11,551.3	1,732.0	
19	Rate Schedule 25	1,048.9	840.1	(208.8)	
20	Rate Schedule 46	1,696.2	2,565.7	869.5	
21	Byron Creek	75.2	5.5	(69.7)	
22	BC Hydro IG	16,425.8	16,470.0	44.2	
23	VIGJV	4,745.0	4,758.0	13.0	
24	Total	235,383.4	235,393.3	9.9	
25					
26	**REVENUE AT EXISTING RATES**				
27	Residential				
28	Rate Schedule 1	$ 709,672	$ 739,480	$ 29,808	
29	Commercial				
30	Rate Schedule 2	214,975	216,466	1,491	
31	Rate Schedule 3	129,060	159,001	29,941	
32	Rate Schedule 23	32,300	16,230	(16,070)	
33	Industrial				
34	Rate Schedule 4	606	689	83	
35	Rate Schedule 5	15,092	42,121	27,029	
36	Rate Schedule 6	195	107	(88)	
37	Rate Schedule 7	1,196	27,448	26,252	
38	Rate Schedule 22 - Firm Service	6,633	7,178	545	
39	Rate Schedule 22 - Interruptible Service	22,986	18,088	(4,898)	
40	Rate Schedule 25	33,486	22,658	(10,828)	
41	Rate Schedule 27	11,938	7,124	(4,814)	
42	Bypass and Special Rates				
43	Rate Schedule 22 - Firm Service	788	802	14	
44	Rate Schedule 25	481	414	(67)	
45	Rate Schedule 46	13,489	20,617	7,128	
46	Byron Creek	118	126	8	
47	BC Hydro IG	15,736	15,778	42	
48	VIGJV	4,689	4,821	132	
49	Total	$ 1,213,439	$ 1,299,148	$ 85,708	

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 18

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 217,846	$ 243,395	$ 25,549	
4	Commercial				
5	Rate Schedule 2	82,146	87,691	5,545	
6	Rate Schedule 3	55,083	71,602	16,519	
7	Rate Schedule 23	126	80	(46)	
8	Industrial				
9	Rate Schedule 4	315	382	67	
10	Rate Schedule 5	6,965	21,036	14,071	
11	Rate Schedule 6	72	42	(30)	
12	Rate Schedule 7	703	17,662	16,959	
13	Rate Schedule 22 - Firm Service	209	289	80	
14	Rate Schedule 22 - Interruptible Service	222	203	(19)	
15	Rate Schedule 25	192	162	(30)	
16	Rate Schedule 27	104	78	(26)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	191	193	2	
19	Rate Schedule 25	20	14	(6)	
20	Rate Schedule 46	5,088	6,989	1,901	
21	Byron Creek	-	-	-	
22	BC Hydro IG	-	-	-	
23	VIGJV	-	-	-	
24	Total	$ 369,282	$ 449,818	$ 80,536	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Approved Margin	2020 Projection Margin at Existing Rates	2020 Projection Effective Increase	2020 Projection Margin at Revised Rates	2020 Projection Revenue at Existing Rates	2020 Projection Effective Increase	2020 Projection Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 491,826	$ 496,085	$ 9,936	$ 506,021	$ 739,480	$ 9,936	$ 749,416	945,421	81,063.9	
4	Commercial										
5	Rate Schedule 2	132,829	128,775	2,579	131,354	216,466	2,579	219,045	88,913	28,933.1	
6	Rate Schedule 3	73,977	87,399	1,750	89,149	159,001	1,750	160,751	6,933	25,274.7	
7	Rate Schedule 23	32,174	16,150	323	16,473	16,230	323	16,553	876	4,799.4	
8	Industrial										
9	Rate Schedule 4	291	307	6	313	689	6	695	19	145.1	
10	Rate Schedule 5	8,127	21,085	422	21,507	42,121	422	42,543	542	8,215.2	
11	Rate Schedule 6	123	65	1	66	107	1	108	7	21.3	
12	Rate Schedule 7	493	9,786	196	9,982	27,448	196	27,644	46	6,851.5	
13	Rate Schedule 22 - Firm Service	6,424	6,889	138	7,027	7,178	138	7,316	9	11,938.3	
14	Rate Schedule 22 - Interruptible Service	22,764	17,885	358	18,243	18,088	358	18,446	26	17,551.9	
15	Rate Schedule 25	33,294	22,496	450	22,946	22,658	450	23,108	348	9,742.8	
16	Rate Schedule 27	11,834	7,046	141	7,187	7,124	141	7,265	72	4,665.5	
17	Total Non-Bypass	$ 814,155	$ 813,968	$ 16,300	$ 830,268	$ 1,256,590	$ 16,300	$ 1,272,890	1,043,212	199,202.7	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 597	$ 609		$ 609	$ 802		$ 802	6	11,551.3	
22	Rate Schedule 25	461	400		400	414		414	4	840.1	
23	Rate Schedule 46	8,401	13,628		13,628	20,617		20,617	34	2,565.7	
24	Byron Creek	118	126		126	126		126	1	5.5	
25	BC Hydro IG	15,736	15,778		15,778	15,778		15,778	1	16,470.0	
26	VIGJV	4,689	4,821		4,821	4,821		4,821	1	4,758.0	
27	Total Bypass & Special	$ 30,002	$ 35,362	$ -	$ 35,362	$ 42,558	$ -	$ 42,558	47	36,190.6	
28											
29											
30	Total	$ 844,157	$ 849,330	$ 16,300	$ 865,630	$ 1,299,148	$ 16,300	$ 1,315,448	1,043,259	235,393.3	
31											
32	**Effective Increase**			2.00%			1.30%				

OPERATING AND MAINTENANCE EXPENSE Schedule 20
FOR THE YEAR ENDING DECEMBER 31, 2020
($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	2019 Base Unit Cost O&M	$ 246			
3	2020 Net Inflation Factor	2.290%			Schedule 3, Line 9, Column 3
4	2020 Base Unit Cost O&M	$ 252			Line 2 x (1 + Line 3)
5					
6	2020 Average Customer Forecast - Rate Setting Purpose	1,040,410			Schedule 3, Line 22, Column 3
7					
8	2020 Inflation Indexed O&M	$ 261,798		$ 261,798	Line 4 x Line 6 / 1000
9					
10	**O&M Tracked Outside of Formula**				
11	Pension & OPEB (O&M Portion)		$ 21,147		
12	Insurance		8,521		
13	Biomethane O&M		1,807		
14	NGT O&M		1,694		
15	LNG Production O&M		7,861		
16	Integrity Digs		4,400		
17	Renewable Gas Development		400		
18	BCUC fees		6,782		
19	Sub-total		$ 52,612	52,612	Sum of Lines 11 through 18
20					
21	**Total Gross O&M**			$ 314,410	Line 8 + Line 19
22	O&M Transferred to Biomethane BVA			(1,807)	
23	Capitalized Overhead			(50,306)	-16 % x Line 21
24	**Net O&M Expense**			$ 262,297	Sum of Lines 21 through 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 21

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 201,052	$ 191,772	$ (9,280)	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(510)	(680)	(170)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,206)	(1,649)	(443)	Schedule 7.2, Line 37, Column 7
5		199,336	189,443	(9,893)	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 67,260	$ 86,255	$ 18,995	Schedule 11.1, Line 26, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(26)	(36)	(10)	Schedule 11.1, Line 27, Column 6
10	Non-Rate Base Deferrals	(26,871)	(35,186)	(8,315)	Schedule 12, Line 27, Column 6
11	CIAC	(9,028)	(8,344)	684	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		31,363	42,717	11,354	
14					
15	Total	$ 230,699	$ 232,160	$ 1,461	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 22

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 55,245	$ 56,709	$ 1,464	
2	1% In-Lieu of Municipal Taxes	12,333	11,293	(1,040)	
3					
4	Total	$ 67,578	$ 68,002	$ 424	
5					
6	Total Property Tax Expense per Line 4	$ 67,578	$ 68,002		
7	Less: Property Tax Transferred to Biomethane BVA	(19)	(43)		
8	**Net Property Tax Expense**	$ 67,559	$ 67,959		

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 23

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,549	$ 1,671	$ (878)	
2	Application Charge	1,925	1,965	40	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	17,072	10,877	(6,195)	
6	NGT Tanker Rental Revenue	680	569	(111)	
7	NGT Overhead and Marketing Recovery	325	284	(41)	
8	Biomethane Other Revenue	614	937	323	
9	LNG Mitigation Revenue from Midstream	18,039	18,039	-	
10	CNG & LNG Service Revenues	3,373	2,939	(434)	
11					
12	Total	$ 44,893	$ 37,597	$ (7,296)	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 24

Line No.	Particulars	2019 Approved	2020 Projection	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 291,732	$ 315,305	$ 23,573	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(140,241)	(145,283)	(5,042)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(8,271)	(73,110)	(64,839)	Line 36
4	Accounting Income After Tax	$ 143,220	$ 96,912	$ (46,308)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 196,192	$ 132,756	$ (63,436)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 52,972	$ 35,844	$ (17,128)	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 52,972	$ 35,844	$ (17,128)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	199,336	189,443	(9,893)	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	40,363	51,033	10,670	Schedule 21, Line 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	944	1,041	97	
22	Vehicles: Interest & Capitalized Depreciation	1,260	1,674	414	
23	Pension Expense	9,273	21,464	12,191	
24	OPEB Expense	9,453	7,973	(1,480)	
25					
26	Deductions:				
27	Capital Cost Allowance	(214,235)	(272,255)	(58,020)	Schedule 25, Line 26, Column 6
28	CIAC Amortization	(9,000)	(8,316)	684	Schedule 21, Line 11+12, Column 3
29	Debt Issue Costs	(1,976)	(2,108)	(132)	
30	Vehicle Lease Payment	(993)	(509)	484	
31	Pension Contributions	(14,594)	(12,697)	1,897	
32	OPEB Contributions	(1,833)	(2,741)	(908)	
33	Overheads Capitalized Expensed for Tax Purposes	(11,246)	(25,153)	(13,907)	
34	Removal Costs	(14,231)	(15,558)	(1,327)	Schedule 11.1, Line 7, Column 4
35	Major Inspection Costs	(1,992)	(7,601)	(5,609)	
36	Total	$ (8,271)	$ (73,110)	$ (64,839)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2020 UCC Balance	Post Nov 21, 2018 Premium Adjustments	2020 Additions	2020 CCA	12/31/2020 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,011,585	$ 2,328	$ 4,656	$ (40,743)	$ 975,498
2	1 (LNG Plant - post Feb 2015)	4%	16,514	-	-	(661)	15,853
3	1(b)	6%	93,959	4,347	8,693	(6,420)	96,232
4	2	6%	92,418	-	-	(5,545)	86,873
5	3	5%	1,778	-	-	(89)	1,689
6	6	10%	295	-	-	(30)	265
7	7	15%	22,758	1,495	2,991	(4,087)	21,662
8	8	20%	26,591	4,306	8,613	(7,902)	27,302
9	10	30%	15,147	4,037	8,074	(8,177)	15,044
10	10.1	30%	264	-	-	(79)	185
11	12	100%	2,208	-	18,673	(20,881)	-
12	13	manual	2,705	-	-	(509)	2,196
13	14	manual	75	-	-	(25)	50
14	14.1 (pre 2017)	7%	17,632	-	-	(1,234)	16,398
15	14.1 (post 2016)	5%	5,889	-	-	(294)	5,595
16	17	8%	1,137	-	-	(91)	1,046
17	38	30%	3,062	-	-	(919)	2,143
18	43.2	50%	784	-	1,050	(1,442)	392
19	45	45%	3	-	-	(1)	2
20	47	8%	180,733	-	-	(14,459)	166,274
21	47 (LNG Plant - post Feb 2015)	8%	188,629	-	-	(15,091)	173,538
22	49	8%	328,373	38,188	76,376	(35,435)	369,314
23	50	55%	7,050	4,668	9,337	(11,580)	4,807
24	51	6%	1,321,333	96,008	192,016	(96,561)	1,416,788
25							
26	Total		$ 3,340,922	$ 155,377	$ 330,479	$ (272,255)	$ 3,399,146

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Approved Earned Return	2020 Amount	2020 Ratio	2020 Average Embedded Cost	2020 Cost Component	2020 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 135,725	$ 2,881,578	57.09%	4.91%	2.81%	$ 141,614	$ 5,889	Schedule 27, Line 30&32, Column 5&6&7
2	Short Term Debt	4,516	222,345	4.41%	1.65%	0.07%	3,669	(847)	
3	Common Equity	151,491	1,943,106	38.50%	8.75%	3.37%	170,022	18,531	
4									
5	Total	$ 291,732	$ 5,047,029	100.00%		6.25%	$ 315,305	$ 23,573	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 27

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(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	123,730	124,571	2.644%	3,294	
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	198,000	93,989	2.588%	2,432	
17								
18								
19	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
20	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
21								
22	LILO Obligations - Nelson	March 1, 2004	February 28, 2021		2,559	8.910%	228	
23	LILO Obligations - Prince George	October 31, 2004	October 31, 2021		19,885	9.122%	1,814	
24	LILO Obligations - Creston	November 1, 2005	October 31, 2022		1,917	8.138%	156	
25								
26	Vehicle Lease Obligation				780	3.205%	25	
27								
28	Sub-Total				$ 2,888,701		$ 141,982	
29	Less: Fort Nelson Division Portion of Long Term Debt				(7,123)		(368)	
30	Total				$ 2,881,578		$ 141,614	
31								
32	Average Embedded Cost					4.91%		
33								
34	* Interest Rate is Effective interest rate as it includes amortization of debt issue costs							

SUMMARY OF RATE CHANGE - 2021
FOR THE YEAR ENDING DECEMBER 31, 2021
($millions)

Schedule 1

Line No.	Particulars	2021 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (9.288)		
3	Change in Other Revenue	(4.398)	(13.686)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	14.940		
7	Capitalized Overhead Change	(2.397)	12.543	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		9.980	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.189)		
14	Deferrals	38.490	38.301	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	(3.344)		
18	Financing Ratio Changes	3.157		
19	Rate Base Growth	10.449	10.262	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	3.852		
23	Other Income Taxes Changes	18.086	21.938	
24				
25	**2020 Revenue Deficiency - Year End Projection**		10.338	
26	**2021 Revenue Deficiency**		(35.287)	
27				
28	**REVENUE DEFICIENCY (SURPLUS)**		**$ 54.389**	Schedule 16, Line 11, Column 4
29				
30	Non-Bypass Margin at 2020 Approved Interim Rates		824.897	Schedule 19, Line 17, Column 3
31	Rate Change		6.59%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 2

Line No.	Particulars	2020 Projection	2021 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 6,924,038	$ 7,565,637	$ 641,599	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	126,088	-	(126,088)	Schedule 6.2, Line 35, Column 4
3	Net Additions	515,511	310,111	(205,400)	Schedule 6.2, Line 35, Column 5+6+7
4	Plant in Service, Ending	7,565,637	7,875,748	310,111	
5					
6	Accumulated Depreciation Beginning	$ (2,197,878)	$ (2,284,843)	$ (86,965)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(86,965)	(137,436)	(50,471)	Schedule 7.2, Line 35, Column 7+8
9	Accumulated Depreciation Ending	(2,284,843)	(2,422,279)	(137,436)	
10					
11	CIAC, Beginning	$ (439,264)	$ (446,483)	$ (7,219)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(7,219)	(6,005)	1,214	Schedule 9, Line 6, Column 5+6
14	CIAC, Ending	(446,483)	(452,488)	(6,005)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 170,507	$ 178,851	$ 8,344	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,344	8,533	189	Schedule 9, Line 13, Column 5+6
19	Accumulated Amortization Ending - CIAC	178,851	187,384	8,533	
20					
21	Net Plant in Service, Mid-Year	$ 4,798,327	$ 5,100,764	$ 302,437	
22					
23	Adjustment for timing of Capital additions	$ 159,575	$ 38,361	$ (121,214)	
24	Capital Work in Progress, No AFUDC	36,412	36,412	-	
25	Unamortized Deferred Charges	(428)	(19,923)	(19,495)	Schedule 11.1, Line 26, Column 10
26	Working Capital	53,247	57,008	3,761	Schedule 13, Line 15, Column 3
27	Deferred Income Taxes Regulatory Asset	563,888	603,716	39,828	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(563,888)	(603,716)	(39,828)	Schedule 15, Line 6, Column 3
29	LILO Benefit	(104)	(41)	63	
30					
31	Mid-Year Utility Rate Base	$ 5,047,029	$ 5,212,581	$ 165,552	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	Reference	2020	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Formula Cost Drivers**				
2	CPI		2.692%	1.596%	
3	AWE		2.881%	5.946%	
4	Labour Split				
5	Non Labour		48.000%	48.000%	
6	Labour		52.000%	52.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.790%	3.858%	
8	Productivity Factor	G-165-20	-0.500%	-0.500%	
9	Net Inflation Factor	Line 7 + Line 8	2.290%	3.358%	
10					
11					
12	**Growth in Average Customer Calculation**				
13	Average Customer Forecast - Prior Year	Schedule 19 (2020), Line 30, Column 9	1,031,862	1,043,259	
14	Average Customer Forecast - Test Year	Schedule 19, Line 30, Column 9	1,043,259	1,053,292	
15	Average Customer Change	Line 14 - Line 13	11,397	10,033	
16	Customer Growth Factor Multiplier	G-165-20	75%	75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16	8,548	7,525	
18					
19	**Average Customer Continuity for Rate Setting Purposes**				
20	Average Customer Forecast - Prior Year	Prior Year Line 22	1,031,862	1,040,410	
21	Change in Customers - Rate Setting Purposes	Line 17	8,548	7,525	
22	Average Customer Forecast - Rate Setting Purposes	Line 20 + Line 21	1,040,410	1,047,935	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2021
($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	2020 Unit Cost Growth Capital	$ 3,789				
3	2021 Net Inflation Factor	3.358%				Schedule 3, Line 9, Column 4
4	2021 Unit Cost Growth Capital	$ 3,916				
5	2021 Gross Customer Additions	16,000				
6	2021 Inflation Indexed Growth Capital	$ 62,657			$ 62,657	
7	2021 Growth CIAC				2,253	
8	2021 Inflation Indexed Gross Growth Capital				$ 64,910	
9						
10	**Capital Tracked Outside of Formula**					
11	Pension & OPEB (Growth Capital Portion)			$ 1,832		
12	Biomethane Upgraders			15,690		
13	Biomethane Interconnect			4,460		
14	NGT Assets			5,030		
15	Sustainment Capital			112,944		
16	Other Capital			49,916		
17	Sub-total			$ 189,872	189,872	
18						
19	**Total Capital Expenditures Before CIAC**				$ 254,782	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 5

Line No.	Particulars		2021 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	64,910	Schedule 4, Line 8
3	Forecast Capital Expenditures		189,872	Schedule 4, Line 17
4	Total Capital Expenditures	$	254,782	
5				
6	**Special Projects and CPCN's**			
7	LMIPSU	$	16,170	
8	IGU		60,630	
9	Tilbury Expansion Project		4,147	
10	Total Capital Expenditures	$	80,947	
11				
12	**Total Capital Expenditures**	$	335,729	
13				
14				
15	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
16				
17	Regular Capital Expenditures	$	254,782	Line 4
18	Add - Capitalized Overheads		52,703	Schedule 20, Line 23
19	Add - AFUDC		3,654	
20	Gross Capital Expenditures		311,139	
21	Change in Work in Progress		(17,300)	
22	**Total Regular Additions to Plant**	$	293,839	
23				
24	Special Projects and CPCN's Capital Expenditures	$	80,947	Line 10
25	Add - AFUDC		2,301	
26	Gross Capital Expenditures		83,248	
27	Change in Work in Progress		(2,380)	
28	**Total Special Projects and CPCN Additions to Plant**	$	80,868	
29				
30	**Grand Total Additions to Plant**	$	374,707	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Account	Particulars	12/31/2020	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	175-00	Unamortized Conversion Expense - Squamish	777	-	-	-	-	777	
4	178-00	Organization Expense	728	-	-	-	-	728	
5	401-01	Franchise and Consents	297	-	-	-	-	297	
6	402-11	Utility Plant Acquisition Adjustment	62	-	-	-	-	62	
7	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
8	440-02	Water/Land Rights Tilbury	4,299	-	-	-	-	4,299	
9	461-01	Transmission Land Rights	51,232	-	-	-	-	51,232	
10	461-02	Transmission Land Rights - Mt. Hayes	609	-	-	-	-	609	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
13	471-01	Distribution Land Rights	3,467	-	-	-	-	3,467	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	68,266	-	-	9,463	(10,375)	67,354	
16	402-02	Application Software - 20%	26,461	-	-	9,240	(3,314)	32,387	
17			$ 158,255	$ -	$ -	$ 18,703	$ (13,689)	$ 163,269	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	-	-	-	-	1,199	
22	433-00	Manufact'd Gas - Equipment	610	-	-	-	-	610	
23	434-00	Manufact'd Gas - Gas Holders	2,955	-	-	-	-	2,955	
24	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	-	-	-	-	1,714	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	97,741	-	-	-	-	97,741	
28	443-00	Gas Holders - Storage (Tilbury)	194,284	-	4,147	-	-	198,431	
29	448-11	Piping (Tilbury)	47,779	-	-	-	-	47,779	
30	448-21	Pre-treatment (Tilbury)	32,545	-	-	-	-	32,545	
31	448-31	Liquefaction Equipment (Tilbury)	86,281	-	-	-	-	86,281	
32	449-00	Local Storage Equipment (Tilbury)	27,862	-	-	-	-	27,862	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	-	-	-	-	19,045	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	-	-	-	-	61,774	
36	448-41	Send out Equipment(Tilbury)	6,795	-	-	-	-	6,795	
37	448-51	Sub-station and Electric (Tilbury)	36,216	-	-	-	-	36,216	
38	448-61	Control Room (Tilbury)	3,658	-	-	-	-	3,658	
39	448-10	Piping (Mount Hayes)	12,455	-	-	-	-	12,455	
40	448-20	Pre-treatment (Mount Hayes)	29,238	-	-	-	-	29,238	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	-	-	-	-	28,880	
42	448-40	Send out Equipment (Mount Hayes)	23,552	-	-	-	-	23,552	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
44	448-60	Control Room (Mount Hayes)	6,425	-	-	-	-	6,425	
45	448-65	MH Inspection (Mount Hayes)	1,666	-	-	-	(1,666)	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	-	-	-	-	5,727	
47			$ 766,834	$ -	$ 4,147	$ -	$ (1,666)	$ 769,315	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2020	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,805	$ -	$ -	$ -	$ -	$ 10,805	
3	461-00	Transmission Land Rights	-	-	-	-	-	-	
4	462-00	Compressor Structures	34,752	-	-	2,235	(345)	36,642	
5	463-00	Measuring Structures	20,210	-	-	-	-	20,210	
6	464-00	Other Structures & Improvements	8,745	-	-	1,866	(3)	10,608	
7	465-00	Mains	1,441,539	-	47,109	22,435	(1,990)	1,509,093	
8	465-20	Mains - INSPECTION	41,257	-	-	10,448	(8,944)	42,761	
9	465-11	IP Transmission Pipeline - Whistler	58,689	-	-	-	-	58,689	
10	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
11	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
12	466-00	Compressor Equipment	197,592	-	-	3,603	(887)	200,308	
13	466-10	Compressor Equipment - OVERHAUL	8,191	-	-	4	-	8,195	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	6,298	-	-	1,245	-	7,543	
15	467-10	Measuring & Regulating Equipment	86,937	-	-	7,897	(298)	94,536	
16	467-20	Telemetering	18,289	-	-	-	-	18,289	
17	467-31	IP Intermediate Pressure Whistler	343	-	-	38	-	381	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
19	468-00	Communication Structures & Equipment	7,006	-	-	3,086	-	10,092	
20			$ 1,948,622	$ -	$ 47,109	$ 52,857	$ (12,467)	$ 2,036,121	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 5,457	$ -	$ -	$ -	$ -	$ 5,457	
24	472-00	Structures & Improvements	48,501	-	1,286	1,801	(60)	51,528	
25	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
26	473-00	Services	1,359,609	-	-	71,193	(3,837)	1,426,965	
27	474-00	House Regulators & Meter Installations	170,544	-	-	-	(6,183)	164,361	
28	474-02	Meters/Regulators Installations	193,544	-	-	21,190	-	214,734	
29	475-00	Mains	1,932,931	-	26,396	57,825	(3,412)	2,013,740	
30	476-00	Compressor Equipment	614	-	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	198,224	-	1,287	13,678	(776)	212,413	
32	477-20	Telemetering	21,640	-	643	768	(44)	23,007	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
34	478-10	Meters	293,352	-	-	16,883	(7,150)	303,085	
35	478-20	Instruments	14,711	-	-	696	-	15,407	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 4,239,404	$ -	$ 29,612	$ 184,034	$ (21,462)	$ 4,431,588	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 710	$ -	$ -	$ -	$ -	$ 710	
41	475-10	Bio Gas Mains – Municipal Land	1,601	-	-	-	-	1,601	
42	475-20	Bio Gas Mains – Private Land	55	-	-	-	-	55	
43	418-10	Bio Gas Purification Overhaul	20	-	-	-	-	20	
44	418-20	Bio Gas Purification Upgrader	10,992	-	-	2,910	-	13,902	
45	477-40	Bio Gas Reg & Meter Equipment	2,751	-	-	-	-	2,751	
46	478-30	Bio Gas Meters	36	-	-	-	-	36	
47	474-10	Bio Gas Reg & Meter Installations	226	-	-	-	-	226	
48	483-25	RNG Comp S/W	138	-	-	-	-	138	
49			$ 16,529	$ -	$ -	$ 2,910	$ -	$ 19,439	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 6.2

Line No.	Account	Particulars	12/31/2020	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 19,192	$ -	$ -	$ 3,085	$ -	$ 22,277	
3	476-20	NG Transportation LNG Dispensing Equipment	13,123	-	-	2,048	-	15,171	
4	476-30	NG Transportation CNG Foundations	2,789	-	-	-	-	2,789	
5	476-40	NG Transportation LNG Foundations	1,311	-	-	-	-	1,311	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,494	-	-	-	-	1,494	
7	476-60	NG Transportation CNG Dehydrator	554	-	-	-	-	554	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 38,463	$ -	$ -	$ 5,133	$ -	$ 43,596	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 31,306	$ -	$ -	$ -	$ -	$ 31,306	
13	482-10	Frame Buildings	24,658	-	-	-	-	24,658	
14	482-20	Masonry Buildings	123,468	-	-	3,100	(79)	126,489	
15	482-30	Leasehold Improvement	5,771	-	-	-	(4,098)	1,673	
16	483-30	GP Office Equipment	2,919	-	-	405	(198)	3,126	
17	483-40	GP Furniture	17,065	-	-	3,092	(934)	19,223	
18	483-10	GP Computer Hardware	42,309	-	-	9,268	(5,073)	46,504	
19	483-20	GP Computer Software	6,356	-	-	-	(1,192)	5,164	
20	484-00	Vehicles	43,953	-	-	7,940	-	51,893	
21	484-10	Vehicles - Leased	16,879	-	-	-	(1,458)	15,421	
22	485-10	Heavy Work Equipment	750	-	-	-	-	750	
23	485-20	Heavy Mobile Equipment	9,277	-	-	-	-	9,277	
24	486-00	Small Tools & Equipment	54,217	-	-	4,820	(1,550)	57,487	
25	487-20	Equipment on Customer's Premises	3	-	-	-	(3)	-	
26	488-10	Telephone	2,131	-	-	-	(310)	1,821	
27	488-20	Radio	16,468	-	-	1,577	(417)	17,628	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 397,530	$ -	$ -	$ 30,202	$ (15,312)	$ 412,420	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 7,565,637	$ -	$ 80,868	$ 293,839	$ (64,596)	$ 7,875,748	
36									
37		Cross Reference			Schedule 5, Line 28, Column 2	Schedule 5, Line 22, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2020	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 64	$ -	$ 1	$ -	$ -	$ -	$ 65	
3	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	777	-	-	-	-	-	777	
4	178-00	Organization Expense	728	1.00%	450	-	7	-	-	-	457	
5	401-01	Franchise and Consents	297	1.08%	245	-	11	-	-	-	256	
6	402-11	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	-	62	
7	402-03	Other Intangible Plant	1,907	2.50%	1,198	-	48	-	-	-	1,246	
8	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	51,232	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	609	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
13	471-01	Distribution Land Rights	3,467	0.00%	248	-	-	-	-	-	248	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	68,266	12.50%	31,192	-	8,533	(10,375)	-	-	29,350	
16	402-02	Application Software - 20%	26,461	20.00%	8,294	-	5,292	(3,314)	-	-	10,272	
17			$ 158,255		$ 44,316	$ -	$ 13,892	$ (13,689)	$ -	$ -	$ 44,519	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	2.50%	395	-	30	-	-	-	425	
22	433-00	Manufact'd Gas - Equipment	610	5.00%	314	-	30	-	-	-	344	
23	434-00	Manufact'd Gas - Gas Holders	2,955	2.50%	804	-	74	-	-	-	878	
24	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	169	-	15	-	-	-	184	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	5.00%	1,159	-	86	-	-	-	1,245	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	97,741	2.20%	8,901	-	2,150	-	-	-	11,051	
28	443-00	Gas Holders - Storage (Tilbury)	198,431	1.23%	18,355	-	2,390	-	-	-	20,745	
29	448-11	Piping (Tilbury)	47,779	2.45%	1,907	-	1,171	-	-	-	3,078	
30	448-21	Pre-treatment (Tilbury)	32,545	3.84%	2,471	-	1,250	-	-	-	3,721	
31	448-31	Liquefaction Equipment (Tilbury)	86,281	2.45%	4,200	-	2,113	-	-	-	6,313	
32	449-00	Local Storage Equipment (Tilbury)	27,862	2.77%	18,950	-	772	-	-	-	19,722	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	3.85%	6,828	-	733	-	-	-	7,561	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	1.65%	9,618	-	1,019	-	-	-	10,637	
36	448-41	Send out Equipment(Tilbury)	6,795	2.41%	325	-	164	-	-	-	489	
37	448-51	Sub-station and Electric (Tilbury)	36,216	2.41%	1,746	-	873	-	-	-	2,619	
38	448-61	Control Room (Tilbury)	3,658	6.09%	451	-	223	-	-	-	674	
39	448-10	Piping (Mount Hayes)	12,455	2.45%	2,805	-	305	-	-	-	3,110	
40	448-20	Pre-treatment (Mount Hayes)	29,238	3.84%	10,946	-	1,123	-	-	-	12,069	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	2.45%	6,847	-	707	-	-	-	7,554	
42	448-40	Send out Equipment (Mount Hayes)	23,552	2.41%	5,499	-	568	-	-	-	6,067	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.41%	5,141	-	525	-	-	-	5,666	
44	448-60	Control Room (Mount Hayes)	6,425	6.09%	3,805	-	391	-	-	-	4,196	
45	448-65	MH Inspection (Mount Hayes)	1,666	20.00%	1,338	-	328	(1,666)	-	-	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	3.08%	819	-	176	-	-	-	995	
47			$ 770,981		$ 113,794	$ -	$ 17,216	$ (1,666)	$ -	$ -	$ 129,344	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2020	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,805	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	-	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	34,752	3.32%	19,695	-	1,154	(345)	-	-	20,504	
5	463-00	Measuring Structures	20,210	2.13%	8,233	-	430	-	-	-	8,663	
6	464-00	Other Structures & Improvements	8,745	3.62%	3,640	-	317	(3)	-	-	3,954	
7	465-00	Mains	1,488,648	1.46%	452,834	-	21,734	(1,990)	-	-	472,578	
8	465-20	Mains - INSPECTION	41,257	15.20%	17,221	-	6,271	(8,944)	-	-	14,548	
9	465-11	IP Transmission Pipeline - Whistler	58,689	1.54%	7,335	-	904	-	-	-	8,239	
10	465-30	Mt Hayes - Mains	6,307	1.54%	981	-	97	-	-	-	1,078	
11	465-10	Mains - Byron Creek	1,371	5.03%	1,497	-	69	-	-	-	1,566	
12	466-00	Compressor Equipment	197,592	2.42%	102,525	-	4,782	(887)	-	-	106,420	
13	466-10	Compressor Equipment - OVERHAUL	8,191	10.19%	4,211	-	835	-	-	-	5,046	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	6,298	2.34%	1,714	-	147	-	-	-	1,861	
15	467-10	Measuring & Regulating Equipment	86,937	2.12%	29,229	-	1,843	(298)	-	-	30,774	
16	467-20	Telemetering	18,289	8.97%	13,229	-	1,640	-	-	-	14,869	
17	467-31	IP Intermediate Pressure Whistler	343	2.26%	120	-	8	-	-	-	128	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	38	-	7	-	-	-	45	
19	468-00	Communication Structures & Equipment	7,006	0.00%	4,393	-	-	-	-	-	4,393	
20			$ 1,995,731		$ 667,398	$ -	$ 40,238	$ (12,467)	$ -	$ -	$ 695,169	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
24	472-00	Structures & Improvements	49,787	2.15%	11,171	-	1,070	(60)	-	-	12,181	
25	472-10	Structures & Improvements - Byron Creek	124	4.67%	77	-	6	-	-	-	83	
26	473-00	Services	1,359,609	2.18%	365,180	-	29,639	(3,837)	-	-	390,982	
27	474-00	House Regulators & Meter Installations	170,544	7.45%	100,006	-	12,706	(6,183)	-	-	106,529	
28	474-02	Meters/Regulators Installations	193,544	4.55%	36,620	-	8,806	-	-	-	45,426	
29	475-00	Mains	1,959,327	1.35%	540,384	-	26,452	(3,412)	-	-	563,424	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	199,511	2.51%	61,793	-	5,008	(776)	-	-	66,025	
32	477-20	Telemetering	22,283	3.59%	6,907	-	800	(44)	-	-	7,663	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	293,352	6.06%	171,227	-	17,777	(7,150)	-	-	181,854	
35	478-20	Instruments	14,711	2.92%	7,243	-	430	-	-	-	7,673	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 4,269,016		$ 1,302,249	$ -	$ 102,694	$ (21,462)	$ -	$ -	$ 1,383,481	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 710	2.69%	$ 128	$ -	$ 19	$ -	$ -	$ -	$ 147	
41	475-10	Bio Gas Mains – Municipal Land	1,601	1.56%	143	-	25	-	-	-	168	
42	475-20	Bio Gas Mains – Private Land	55	1.56%	8	-	1	-	-	-	9	
43	418-10	Bio Gas Purification Overhaul	20	5.00%	7	-	1	-	-	-	8	
44	418-20	Bio Gas Purification Upgrader	10,992	5.00%	2,842	-	549	-	-	-	3,391	
45	477-40	Bio Gas Reg & Meter Equipment	2,751	3.22%	533	-	89	-	-	-	622	
46	478-30	Bio Gas Meters	36	4.89%	14	-	2	-	-	-	16	
47	474-10	Bio Gas Reg & Meter Installations	226	5.32%	65	-	12	-	-	-	77	
48	483-25	RNG Comp S/W	138	20.00%	111	-	28	-	-	-	139	
49			$ 16,529		$ 3,851	$ -	$ 726	$ -	$ -	$ -	$ 4,577	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 7.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2020	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2021	Cross Reference
	(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	19,192	5.00%	$ 3,893	-	960	-	-	-	$ 4,853	
3	476-20	NG Transportation LNG Dispensing Equipment	13,123	5.00%	3,570	-	656	-	-	-	4,226	
4	476-30	NG Transportation CNG Foundations	2,789	5.00%	659	-	139	-	-	-	798	
5	476-40	NG Transportation LNG Foundations	1,311	5.00%	428	-	66	-	-	-	494	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,494	10.00%	767	-	149	-	-	-	916	
7	476-60	NG Transportation CNG Dehydrator	554	5.00%	154	-	28	-	-	-	182	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 38,463		$ 9,471	$ -	$ 1,998	$ -	$ -	$ -	$ 11,469	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 31,306	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	24,658	3.17%	12,544	-	781	-	-	-	13,325	
14	482-20	Masonry Buildings	123,468	1.52%	33,115	-	1,877	(79)	-	-	34,913	
15	482-30	Leasehold Improvement	5,771	9.49%	4,555	-	546	(4,098)	-	-	1,003	
16	483-30	GP Office Equipment	2,919	6.67%	1,347	-	195	(198)	-	-	1,344	
17	483-40	GP Furniture	17,065	5.00%	5,668	-	853	(934)	-	-	5,587	
18	483-10	GP Computer Hardware	42,309	25.00%	16,324	-	10,577	(5,073)	-	-	21,828	
19	483-20	GP Computer Software	6,356	12.50%	3,304	-	795	(1,192)	-	-	2,907	
20	484-00	Vehicles	43,953	11.07%	15,404	-	4,866	-	-	-	20,270	
21	484-10	Vehicles - Leased	16,879	9.44%	16,340	-	223	(1,458)	-	-	15,105	
22	485-10	Heavy Work Equipment	750	5.14%	449	-	39	-	-	-	488	
23	485-20	Heavy Mobile Equipment	9,277	6.09%	4,153	-	565	-	-	-	4,718	
24	486-00	Small Tools & Equipment	54,217	5.00%	23,836	-	2,711	(1,550)	-	-	24,997	
25	487-20	Equipment on Customer's Premises	3	6.67%	3	-	-	(3)	-	-	-	
26	488-10	Telephone	2,131	6.67%	1,739	-	142	(310)	-	-	1,571	
27	488-20	Radio	16,468	6.67%	4,966	-	1,098	(417)	-	-	5,647	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 397,530		$ 143,764	$ -	$ 25,268	$ (15,312)	$ -	$ -	$ 153,720	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 7,646,505		$ 2,284,843	$ -	$ 202,032	$ (64,596)	$ -	$ -	$ 2,422,279	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(726)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(1,883)					
38		**Net Depreciation Expense**					$ 199,423					
39												
40		Cross Reference	Schedule 6.2, Line 35, Column 3+4+5									

FORTISBC ENERGY INC.

Schedule 8

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars			12/31/2020	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2021	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, 2021**
11 **($000s)**

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2020	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2021	Cross Reference
12										
13										
14–15										
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%	134,176	-	4,238	-	-	138,414	
21									-	
22	**Total**	$ 177,648		$ 134,176	$ -	$ 4,238	$ -	$ -	$ 138,414	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 9

Line No.	Particulars	12/31/2020	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 291,022	$ -	$ -	$ 2,253	$ -	$ 293,275	
3	Transmission Contributions	152,496	-	-	3,101	-	155,597	
4	Others	2,399	-	-	651	-	3,050	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 446,483	$ -	$ -	$ 6,005	$ -	$ 452,488	
7								
8	**Amortization**							
9	Distribution Contributions	$ (121,184)	$ -	$ -	$ (6,201)	$ -	$ (127,385)	
10	Transmission Contributions	(56,553)	-	-	(2,184)	-	(58,737)	
11	Others	(870)	-	-	(120)	-	(990)	
12	Biomethane	(244)	-	-	(28)	-	(272)	
13	**Total**	$ (178,851)	$ -	$ -	$ (8,533)	$ -	$ (187,384)	
14								
15	**Net CIAC**	$ 267,632	$ -	$ -	$ (2,528)	$ -	$ 265,104	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (8,533)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,505)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2020	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**MANUFACTURED GAS / LOCAL STORAGE**							
2	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 1,714	0.00%	$ (22)	$ -	$ -	$ (22)	
3	442-00	Structures & Improvements (Tilbury)	97,741	0.68%	1,514	665	-	2,179	
4	443-00	Gas Holders - Storage (Tilbury)	198,431	1.12%	3,359	2,176	-	5,535	
5	448-11	Piping (Tilbury)	47,779	0.28%	437	134	-	571	
6	448-21	Pre-treatment (Tilbury)	32,545	0.50%	593	163	-	756	
7	448-31	Liquefaction Equipment (Tilbury)	86,281	0.57%	1,853	492	-	2,345	
8	449-00	Local Storage Equipment (Tilbury)	27,862	0.82%	1,121	228	-	1,349	
9	442-01	Structures & Improvements (Mount Hayes)	19,045	0.49%	327	93	-	420	
10	443-05	Gas Holders - Storage (Mount Hayes)	61,774	0.36%	853	222	-	1,075	
11	448-41	Send out Equipment(Tilbury)	6,795	0.28%	44	19	-	63	
12	448-51	Sub-station and Electric (Tilbury)	36,216	0.56%	657	203	-	860	
13	448-10	Piping (Mount Hayes)	12,455	0.28%	128	35	-	163	
14	448-20	Pre-treatment (Mount Hayes)	29,238	0.50%	542	146	-	688	
15	448-30	Liquefaction Equipment (Mount Hayes)	28,880	0.57%	630	165	-	795	
16	448-40	Send out Equipment (Mount Hayes)	23,552	0.28%	252	66	-	318	
17	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.56%	473	122	-	595	
18	449-01	Local Storage Equipment (Mount Hayes)	5,727	0.32%	71	18	-	89	
19			$ 737,823		$ 12,832	$ 4,947	$ -	$ 17,779	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2020	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 34,752	0.11%	$ 484	$ 38	$ -	$ 522	
3	463-00	Measuring Structures	20,210	0.62%	506	125	-	631	
4	464-00	Other Structures & Improvements	8,745	0.29%	92	25	-	117	
5	465-00	Mains	1,488,648	0.42%	26,496	6,252	-	32,748	
6	465-11	IP Transmission Pipeline - Whistler	58,689	0.34%	631	200	-	831	
7	465-30	Mt Hayes - Mains	6,307	0.30%	79	19	-	98	
8	466-00	Compressor Equipment	197,592	0.07%	2,319	138	-	2,457	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	6,298	0.21%	45	13	-	58	
10	467-10	Measuring & Regulating Equipment	86,937	0.16%	872	139	-	1,011	
11	467-20	Telemetering	18,289	0.00%	(26)	-	-	(26)	
12	467-31	IP Intermediate Pressure Whistler	343	0.35%	3	1	-	4	
13	468-00	Communication Structures & Equipment	7,006	0.00%	401	-	-	401	
14			$ 1,933,816		$ 31,902	$ 6,950	$ -	$ 38,852	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (1,393)	$ -	$ -	$ (1,393)	
18	472-00	Structures & Improvements	49,787	0.52%	319	259	-	578	
19	473-00	Services	1,359,609	2.09%	51,558	28,416	(16,080)	63,894	
20	474-00	House Regulators & Meter Installations	170,544	3.37%	(2,052)	5,747	-	3,695	
21	474-02	Meters/Regulators Installations	193,544	0.00%	748	-	-	748	
22	475-00	Mains	1,959,327	0.50%	42,494	9,797	-	52,291	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	199,511	0.45%	3,736	898	-	4,634	
24	477-20	Telemetering	22,283	0.48%	109	107	-	216	
24	478-10	Meters	293,352	0.00%	2,874	-	-	2,874	
24			$ 4,254,028		$ 99,099	$ 45,224	$ (16,080)	$ 128,243	
24									
25		**BIO GAS**							
25	472-20	Bio Gas Struct. & Improvements	$ 710	0.29%	$ 8	$ 2	$ -	$ 10	
25	475-10	Bio Gas Mains – Municipal Land	1,601	0.39%	36	7	-	43	
25	475-20	Bio Gas Mains – Private Land	55	0.39%	1	-	-	1	
27	418-20	Bio Gas Purification Upgrader	10,992	0.24%	95	26	-	121	
29	474-10	Bio Gas Reg & Meter Installations	226	1.44%	13	3	-	16	
31			$ 13,584		$ 153	$ 38	$ -	$ 191	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.2
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2020	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 19,192	0.00%	$ (1)	$ -	$ -	$ (1)	
3			$ 19,192		$ (1)	$ -	$ -	$ (1)	
4									
5		**GENERAL PLANT & EQUIPMENT**							
6	482-10	Frame Buildings	$ 24,658	0.37%	$ (280)	$ 91	$ -	$ (189)	
7	482-20	Masonry Buildings	123,468	0.08%	1,017	99	-	1,116	
8	482-30	Leasehold Improvement	5,771	0.00%	(46)	-	-	(46)	
9	483-30	GP Office Equipment	2,919	0.00%	1	-	-	1	
10	483-40	GP Furniture	17,065	0.00%	(67)	-	-	(67)	
11	484-00	Vehicles	43,953	-3.70%	(297)	(1,626)	-	(1,923)	
12	485-10	Heavy Work Equipment	750	-0.67%	(16)	(5)	-	(21)	
13	485-20	Heavy Mobile Equipment	9,277	-1.80%	(675)	(167)	-	(842)	
14	486-00	Small Tools & Equipment	54,217	0.00%	36	-	-	36	
15	487-20	Equipment on Customer's Premises	3	0.00%	(2)	-	-	(2)	
16	488-20	Radio	16,468	0.00%	(7)	-	-	(7)	
17			$ 298,549		$ (336)	$ (1,608)	$ -	$ (1,944)	
18									
19		**Total**	$ 7,256,992		$ 143,649	$ 55,551	$ (16,080)	$ 183,120	
20		Less: Depreciation & Amortization Transferred to Biomethane BVA				(38)			
21		**Net Salvage Depreciation Expense**				$ 55,513			
22		Cross Reference	Schedule 6.2, Column 3+4+5						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 11

Line No.	Particulars	12/31/2020	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2021	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ 812	$ -	$ -	$ -	$ -	$ (556)	$ 150	$ 406	$ 609	
3	Commodity Cost Reconciliation Account (CCRA)	2,187	-	(2,996)	809	-	-	-	-	1,094	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	17,673	-	-	-	-	(12,106)	3,269	8,836	13,255	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(5,554)	-	4,877	(1,316)	60	5	(1)	(1,929)	(3,742)	
6	Revelstoke Propane Cost Deferral Account	131	-	(180)	49	-	-	-	-	66	
7	SCP Mitigation Revenues Variance Account	1,354	-	-	-	(1,354)	-	-	-	677	
8	Pension & OPEB Variance	(3,176)	-	-	-	1,961	-	-	(1,215)	(2,196)	
9	BCUC Levies Variance	-	-	-	-	-	-	-	-	-	
10	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	
11		$ 13,427	$ -	$ 1,701	$ (458)	$ 667	$ (12,657)	$ 3,418	$ 6,098	$ 9,763	
12	**2. Rate Smoothing Accounts**										
13											
14	**3. Benefits Matching Accounts**										
15	Demand-Side Management (DSM)	$ 165,465	$ 29,948	$ 29,928	$ (8,081)	$ (24,976)	$ -	$ -	$ 192,284	$ 193,849	
16	NGV Conversion Grants	17	-	-	-	(9)	-	-	8	13	
17	Emissions Regulations	(4,011)	-	-	-	1,433	-	-	(2,578)	(3,295)	
18	On-Bill Financing Pilot Program	2	-	(1)	-	-	-	-	1	2	
19	Greenhouse Gas Reduction Regulation Incentives	30,249	-	8,825	(2,383)	(4,981)	-	-	31,710	30,980	
20	CNG and LNG Recoveries	(440)	-	-	-	440	-	-	-	(220)	
21	2016 Cost of Capital Application	-	-	-	-	-	-	-	-	-	
22	BCUC Initiated Inquiry Costs	568	-	100	(27)	(568)	-	-	73	321	
23	2015-2019 Annual Review Costs	-	-	-	-	-	-	-	-	-	
24	2017 Rate Design Application	789	-	-	-	(263)	-	-	526	658	
25	2017 Long Term Resource Plan Application	253	-	-	-	(212)	-	-	41	147	
26	2019-2022 DSM Expenditures Application Costs	50	-	-	-	(25)	-	-	25	38	
27	City of Coquitlam Application Proceeding	281	-	250	(68)	(94)	-	-	369	325	
28		$ 193,223	$ 29,948	$ 39,102	$ (10,559)	$ (29,255)	$ -	$ -	$ 222,459	$ 222,818	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 11.1

Line No.	Particulars	12/31/2020	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2021	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 6,452	$ -	$ -	$ -	$ (739)	$ -	$ -	$ 5,713	$ 6,083	
3	2010-2011 Customer Service O&M and COS	-	-	-	-	-	-	-	-	-	
4	Gas Asset Records Project	1,591	-	-	-	(634)	-	-	957	1,274	
5	BC OneCall Project	63	-	-	-	(55)	-	-	8	36	
6	Gains and Losses on Asset Disposition	12,471	-	-	-	(3,986)	-	-	8,485	10,478	
7	Net Salvage Provision/Cost	(143,649)	-	16,080	-	(55,551)	-	-	(183,120)	(163,385)	
8	PCEC Start Up Costs	656	-	-	-	(44)	-	-	612	634	
9	2022 Long Term Gas Resource Plan Application	215	-	481	(130)	-	-	-	566	391	
10	2020–2024 MRP Application	791	-	-	-	(198)	-	-	593	692	
11	City of Surrey Operating Terms Application Costs	115	-	-	-	(81)	-	-	34	75	
12	IGU Application and Preliminary Stage Development Costs	(776)	-	-	-	388	-	-	(388)	(582)	
13	Annual Review of 2020-2024 Rates	73	-	100	(27)	(73)	-	-	73	73	
14		$ (121,998)	$ -	$ 16,661	$ (157)	$ (60,973)	$ -	$ -	$ (166,467)	$ (144,231)	
15	**4. Retroactive Expense Accounts**										
16											
17	**5.Other Accounts**										
18	Pension & OPEB Funding	$ (315,469)	$ -	$ (16,506)	$ -	$ -	$ -	$ -	$ (331,975)	$ (323,722)	
19	US GAAP Pension & OPEB Funded Status	210,173	-	-	-	-	-	-	210,173	210,173	
20	BFI Costs and Recoveries	(598)	-	-	-	-	-	-	(598)	(598)	
21	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	
22	BVA Balance Transfer	(296)	3,432	-	-	-	(4,297)	1,161	-	1,568	
23	COVID-19 Customer Recovery Fund	3,774	-	2,058	(994)	-	-	-	4,838	4,306	
24		$ (102,416)	$ 3,432	$ (14,448)	$ (994)	$ -	$ (4,297)	$ 1,161	$ (117,562)	$ (108,273)	
25											
26	**Total**	$ (17,764)	$ 33,380	$ 43,016	$ (12,168)	$ (89,561)	$ (16,954)	$ 4,579	$ (55,472)	$ (19,923)	
27	Less: Net Salvage Amortization Transferred to Biomethane BVA					38					
28	**Net Rate Base Deferred Amortization Expense**					$ (89,523)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 12

Line No.	Particulars	12/31/2020	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2021	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ 3,432	$ (3,432)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Flowthrough (2020-2024)	-	-	-	-	-	-	-	-	-	
4	Flowthrough (2014-2019)	-	-	-	-	-	-	-	-	-	
5	Marketer Cost Variance	20	-	(27)	7	-	-	-	-	10	
6		$ 3,452	$ (3,432)	$ (27)	$ 7	$ -	$ -	$ -	$ -	$ 10	
7	**2. Rate Smoothing Accounts**										
8	2017 & 2018 Revenue Surplus Account	$ (25,336)	$ -	$ 34,863	$ (9,527)	$ -	$ -	$ -	$ -	$ (12,668)	
9											
10	**3. Benefits Matching Accounts**										
11	Demand-Side Management (DSM) - Non Rate Base	$ 29,948	$ (29,948)	$ 59,843	$ (15,839)	$ -	$ -	$ -	$ 44,004	$ 22,002	
12	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
13	IGU Application and Preliminary Stage Development Costs	-	-	-	-	-	-	-	-	-	
14	Transmission Integrity Management Capabilities	18,214	-	14,726	(3,632)	-	-	-	29,308	23,761	
15	Clean Growth Innovation Fund	(400)	-	5,079	(1,350)	-	(5,056)	1,365	(362)	(381)	
16		$ 45,364	$ (29,948)	$ 79,648	$ (20,821)	$ -	$ (5,056)	$ 1,365	$ 70,552	$ 42,984	
17	**4. Retroactive Expense Accounts**										
18											
19	**5.Other Accounts**										
20	Mark to Market - Hedging Transactions	$ (1,621)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,621)	$ (1,621)	
21	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
22	2014-2019 Earning Sharing Account	-	-	-	-	-	-	-	-	-	
23	MRP Earnings Sharing Account	-	-	-	-	-	-	-	-	-	
24		$ (1,621)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,621)	$ (1,621)	
25											
26											
27	**Total Non Rate Base Deferral Accounts**	$ 21,859	$ (33,380)	$ 114,484	$ (30,341)	$ -	$ (5,056)	$ 1,365	$ 68,931	$ 28,705	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 13

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 16,629	$ 17,474	$ 845	Schedule 14, Line 29, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,341	1,368	27	
6	Reserve For Bad Debts	-	-	-	Note 1
7	Employee Withholdings	(6,335)	(6,444)	(109)	
8					
9	**Other Working Capital Items**				
10	Transmission Line Pack Gas	1,724	2,103	379	
11	Gas In Storage	38,204	40,786	2,582	
12	Inventory - Materials and Supplied	2,005	2,041	36	
13	Refundable Contributions	(321)	(320)	1	
14					
15	Total	$ 53,247	$ 57,008	$ 3,761	
16					
17	Note 1: Reserve for bad debts included in Cash Working Capital calculation (Schedule 14) beginning in 2020.				

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 14

Line No.	Particulars	2021 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	$ 803,619	40.3	$ 32,385,846		
4	Commercial Tariff Revenue	441,379	37.8	16,684,126		
4	Industrial Tariff Revenue	133,639	47.7	6,374,569		
5	Bypass and Special Rates	66,605	37.6	2,504,347		
6						
7	**Other Revenue**					
8	Late Payment Charges	2,954	53.8	158,925		
9	Application Charges	1,984	39.0	77,376		
10	Other Utility Income	37,057	39.0	1,445,223		
11						
12	Total	$ 1,487,237		$ 59,630,412	40.1	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 515,935	(40.0)	$ (20,637,400)		
16	Operating and Maintenance	274,840	(31.8)	(8,739,912)		
17	Property Taxes	71,811	(1.3)	(93,354)		
18	Operating Fees	9,270	(352.9)	(3,271,318)		
19	Carbon Tax	306,320	(30.7)	(9,404,024)		
20	GST	12,500	(39.7)	(496,250)		
21	PST	5,967	(45.8)	(273,289)		
22	Income Tax	53,930	(15.2)	(819,736)		
23						
24	Total	$ 1,250,572		$ (43,735,283)	(35.0)	
25						
26	Net Lag (Lead) Days				5.1	
27	Total Expenses				$ 1,250,572	
28						
29	Cash Working Capital				$ 17,474	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 15

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (426,473)	$ (454,952)	$ (28,479)	
2	Tax Gross Up	(157,736)	(168,270)	(10,534)	
3	DIT Liability/Asset - End of Year	$ (584,209)	$ (623,222)	$ (39,013)	
4	DIT Liability/Asset - Opening Balance	(543,567)	(584,209)	(40,642)	
5					
6	DIT Liability/Asset - Mid Year	$ (563,888)	$ (603,716)	$ (39,828)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 16

Line No.	Particulars	2020 Projection	2021 Forecast at 2020 Approved Interim Rates	2021 Forecast Revised Revenue	2021 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	153,071	154,208		154,208	1,138	
3	Transportation Volume (TJ)	82,323	79,366		79,366	(2,957)	
4		235,393	233,574	-	233,574	(1,819)	Schedule 17, Line 24, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,205,929	$ 1,297,253	$ -	$ 1,297,253	$ 91,324	
8	Deficiency (Surplus)	14,890	-	49,712	49,712	34,822	
9	Transportation	93,219	93,600	-	93,600	381	
10	Deficiency (Surplus)	1,410		4,677	4,677	3,267	
11	Total	1,315,448	1,390,853	54,389	1,445,242	129,794	Schedule 19, Line 30, Column 8
12				-			
13	**COST OF ENERGY**	449,818	515,935	-	515,935	66,117	Schedule 18, Line 24, Column 3
14							
15	**MARGIN**	865,630	874,918	54,389	929,307	63,677	
16							
17	**EXPENSES**						
18	O&M Expense (net)	262,297	274,840	-	274,840	12,543	Schedule 20, Line 24, Column 4
19	Depreciation & Amortization	232,160	280,441	-	280,441	48,281	Schedule 21, Line 15, Column 3
20	Property Taxes	67,959	71,811	-	71,811	3,852	Schedule 22, Line 8, Column 3
21	Other Revenue	(37,597)	(41,995)	-	(41,995)	(4,398)	Schedule 23, Line 12, Column 3
22	Deferred 2020 / 2021 Revenue Deficiency	(10,338)	(35,287)	-	(35,287)	(24,949)	Schedule 1, Line 26, Column 3
23	Utility Income Before Income Taxes	351,149	325,108	54,389	379,497	28,348	
24							
25	Income Taxes	35,844	39,247	14,683	53,930	18,086	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 315,305	$ 285,861	$ 39,706	$ 325,567	$ 10,262	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 5,047,029	$ 5,212,023		$ 5,212,581	$ 165,552	Schedule 2, Line 31, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.25%	5.49%		6.25%	0.00%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 17

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	81,063.9	79,332.3	(1,731.6)	
4	Commercial				
5	Rate Schedule 2	28,933.1	28,937.2	4.1	
6	Rate Schedule 3	25,274.7	26,203.9	929.2	
7	Rate Schedule 23	4,799.4	4,877.8	78.4	
8	Industrial				
9	Rate Schedule 4	145.1	148.9	3.8	
10	Rate Schedule 5	8,215.2	8,168.9	(46.3)	
11	Rate Schedule 6	21.3	23.4	2.1	
12	Rate Schedule 7	6,851.5	5,924.2	(927.3)	
13	Rate Schedule 22 - Firm Service	11,938.3	10,434.2	(1,504.1)	
14	Rate Schedule 22 - Interruptible Service	17,551.9	15,899.6	(1,652.3)	
15	Rate Schedule 25	9,742.8	10,252.7	509.9	
16	Rate Schedule 27	4,665.5	4,796.0	130.5	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	11,551.3	11,030.7	(520.6)	
19	Rate Schedule 25	840.1	893.6	53.5	
20	Rate Schedule 46	2,565.7	5,469.6	2,903.9	
21	Byron Creek	5.5	11.0	5.5	
22	BC Hydro IG	16,470.0	16,425.0	(45.0)	
23	VIGJV	4,758.0	4,745.0	(13.0)	
24	Total	235,393.3	233,574.0	(1,819.3)	
25					
26	**REVENUE AT EXISTING RATES**				
27	Residential				
28	Rate Schedule 1	$ 739,480	$ 770,705	$ 31,225	
29	Commercial				
30	Rate Schedule 2	216,466	231,366	14,900	
31	Rate Schedule 3	159,001	177,214	18,213	
32	Rate Schedule 23	16,230	16,904	674	
33	Industrial				
34	Rate Schedule 4	689	767	78	
35	Rate Schedule 5	42,121	45,886	3,765	
36	Rate Schedule 6	107	130	23	
37	Rate Schedule 7	27,448	26,451	(997)	
38	Rate Schedule 22 - Firm Service	7,178	6,879	(299)	
39	Rate Schedule 22 - Interruptible Service	18,088	16,919	(1,169)	
40	Rate Schedule 25	22,658	23,575	917	
41	Rate Schedule 27	7,124	7,452	328	
42	Bypass and Special Rates				
43	Rate Schedule 22 - Firm Service	802	802	-	
44	Rate Schedule 25	414	418	4	
45	Rate Schedule 46	20,617	44,734	24,117	
46	Byron Creek	126	109	(17)	
47	BC Hydro IG	15,778	15,735	(43)	
48	VIGJV	4,821	4,807	(14)	
49	Total	$ 1,299,148	$ 1,390,853	$ 91,705	

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 243,395	$ 271,529	$ 28,134	
4	Commercial				
5	Rate Schedule 2	87,691	99,816	12,125	
6	Rate Schedule 3	71,602	84,511	12,909	
7	Rate Schedule 23	80	83	3	
8	Industrial				
9	Rate Schedule 4	382	446	64	
10	Rate Schedule 5	21,036	24,466	3,430	
11	Rate Schedule 6	42	56	14	
12	Rate Schedule 7	17,662	17,743	81	
13	Rate Schedule 22 - Firm Service	289	259	(30)	
14	Rate Schedule 22 - Interruptible Service	203	188	(15)	
15	Rate Schedule 25	162	173	11	
16	Rate Schedule 27	78	81	3	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	193	187	(6)	
19	Rate Schedule 25	14	15	1	
20	Rate Schedule 46	6,989	16,382	9,393	
21	Byron Creek	-	-	-	
22	BC Hydro IG	-	-	-	
23	VIGJV	-	-	-	
24	Total	$ 449,818	$ 515,935	$ 66,117	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projection Margin	2021 Forecast Margin at at 2020 Approved Interim Rates	2021 Forecast Effective Increase	2021 Forecast Margin at Revised Rates	2021 Forecast Revenue at Existing Rates	2021 Forecast Effective Increase	2021 Forecast Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 506,021	$ 499,176	$ 32,914	$ 532,090	$ 770,705	$ 32,914	$ 803,619	954,101	79,332.3	
4	Commercial										
5	Rate Schedule 2	131,354	131,550	8,674	140,224	231,366	8,674	240,040	89,769	28,937.2	
6	Rate Schedule 3	89,149	92,703	6,112	98,815	177,214	6,112	183,326	7,370	26,203.9	
7	Rate Schedule 23	16,473	16,821	1,109	17,930	16,904	1,109	18,013	922	4,877.8	
8	Industrial										
9	Rate Schedule 4	313	321	21	342	767	21	788	20	148.9	
10	Rate Schedule 5	21,507	21,420	1,412	22,832	45,886	1,412	47,298	543	8,168.9	
11	Rate Schedule 6	66	74	5	79	130	5	135	8	23.4	
12	Rate Schedule 7	9,982	8,708	574	9,282	26,451	574	27,025	46	5,924.2	
13	Rate Schedule 22 - Firm Service	7,027	6,620	436	7,056	6,879	436	7,315	9	10,434.2	
14	Rate Schedule 22 - Interruptible Service	18,243	16,731	1,103	17,834	16,919	1,103	18,022	26	15,899.6	
15	Rate Schedule 25	22,946	23,402	1,543	24,945	23,575	1,543	25,118	359	10,252.7	
16	Rate Schedule 27	7,187	7,371	486	7,857	7,452	486	7,938	72	4,796.0	
17	Total Non-Bypass	$ 830,268	$ 824,897	$ 54,389	$ 879,286	$ 1,324,248	$ 54,389	$ 1,378,637	1,053,245	194,999.1	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 609	$ 615		$ 615	$ 802		$ 802	6	11,030.7	
22	Rate Schedule 25	400	403		403	418		418	4	893.6	
23	Rate Schedule 46	13,628	28,352		28,352	44,734		44,734	34	5,469.6	
24	Byron Creek	126	109		109	109		109	1	11.0	
25	BC Hydro IG	15,778	15,735		15,735	15,735		15,735	1	16,425.0	
26	VIGJV	4,821	4,807		4,807	4,807		4,807	1	4,745.0	
27	Total Bypass & Special	$ 35,362	$ 50,021	$ -	$ 50,021	$ 66,605	$ -	$ 66,605	47	38,574.9	
28											
29											
30	Total	$ 865,630	$ 874,918	$ 54,389	$ 929,307	$ 1,390,853	$ 54,389	$ 1,445,242	1,053,292	233,574.0	
31											
32	**Effective Increase**			6.59%			4.11%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2021
($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	2020 Base Unit Cost O&M	$ 252			
3	2021 Net Inflation Factor	3.358%			Schedule 3, Line 9, Column 4
4	2021 Base Unit Cost O&M	$ 260			Line 2 x (1 + Line 3)
5					
6	2021 Average Customer Forecast - Rate Setting Purpose	1,047,935			Schedule 3, Line 22, Column 4
7					
8	2021 Inflation Indexed O&M	$ 272,547		$ 272,547	Line 4 x Line 6 / 1000
9					
10	**O&M Tracked Outside of Formula**				
11	Pension & OPEB (O&M Portion)		$ 22,354		
12	Insurance		9,908		
13	Biomethane O&M		1,848		
14	NGT O&M		1,813		
15	LNG Production O&M		8,081		
16	Integrity Digs		4,800		
17	Renewable Gas Development		750		
18	BCUC fees		7,290		
19	Sub-total		$ 56,844	56,844	Sum of Lines 11 through 18
20					
21	**Total Gross O&M**			$ 329,391	Line 8 + Line 19
22	O&M Transferred to Biomethane BVA			(1,848)	
23	Capitalized Overhead			(52,703)	-16 % x Line 21
24	**Net O&M Expense**			$ 274,840	Sum of Lines 21 through 23

Schedule 21

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars (1)	2020 Projection (2)	2021 Forecast (3)	Change (4)	Cross Reference (5)
1	**Depreciation**				
2	Depreciation Expense	$ 191,772	$ 202,032	$ 10,260	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(680)	(726)	(46)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,649)	(1,883)	(234)	Schedule 7.2, Line 37, Column 7
5		189,443	199,423	9,980	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 86,255	$ 89,561	$ 3,306	Schedule 11.1, Line 26, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(36)	(38)	(2)	Schedule 11.1, Line 27, Column 6
10	Non-Rate Base Deferrals	(35,186)	-	35,186	Schedule 12, Line 27, Column 6
11	CIAC	(8,344)	(8,533)	(189)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		42,717	81,018	38,301	
14					
15	Total	$ 232,160	$ 280,441	$ 48,281	

PROPERTY AND SUNDRY TAXES Schedule 22
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 56,709	$ 59,471	$ 2,762	
2	1% In-Lieu of Municipal Taxes	11,293	12,423	1,130	
3					
4	Total	$ 68,002	$ 71,894	$ 3,892	
5					
6	Total Property Tax Expense per Line 4	$ 68,002	$ 71,894		
7	Less: Property Tax Transferred to Biomethane BVA	(43)	(83)		
8	**Net Property Tax Expense**	$ 67,959	$ 71,811		

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 23

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 1,671	$ 2,954	$ 1,283	
2	Application Charge	1,965	1,984	19	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	10,877	14,053	3,176	
6	NGT Tanker Rental Revenue	569	774	205	
7	NGT Overhead and Marketing Recovery	284	258	(26)	
8	Biomethane Other Revenue	937	951	14	
9	LNG Mitigation Revenue from Midstream	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,939	2,666	(273)	
11					
12	Total	$ 37,597	$ 41,995	$ 4,398	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 24

Line No.	Particulars	2020 Projection	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 315,305	$ 325,567	$ 10,262	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(145,283)	(149,968)	(4,685)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(73,110)	(29,789)	43,321	Line 36
4	Accounting Income After Tax	$ 96,912	$ 145,810	$ 48,898	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 132,756	$ 199,740	$ 66,984	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 35,844	$ 53,930	$ 18,086	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 35,844	$ 53,930	$ 18,086	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	189,443	199,423	9,980	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	51,033	89,523	38,490	Schedule 21, Line 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,041	1,202	161	
22	Vehicles: Interest & Capitalized Depreciation	1,674	1,894	220	
23	Pension Expense	21,464	23,385	1,921	
24	OPEB Expense	7,973	8,969	996	
25					
26	Deductions:				
27	Capital Cost Allowance	(272,255)	(278,914)	(6,659)	Schedule 25, Line 26, Column 6
28	CIAC Amortization	(8,316)	(8,505)	(189)	Schedule 21, Line 11+12, Column 3
29	Debt Issue Costs	(2,108)	(1,816)	292	
30	Vehicle Lease Payment	(509)	(234)	275	
31	Pension Contributions	(12,697)	(13,038)	(341)	
32	OPEB Contributions	(2,741)	(2,971)	(230)	
33	Overheads Capitalized Expensed for Tax Purposes	(25,153)	(26,352)	(1,199)	
34	Removal Costs	(15,558)	(16,080)	(522)	Schedule 11.1, Line 7, Column 4
35	Major Inspection Costs	(7,601)	(7,475)	126	
36	Total	$ (73,110)	$ (29,789)	$ 43,321	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2020 UCC Balance	Post Nov 21, 2018 Premium Adjustments	2021 Additions	2021 CCA	12/31/2021 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 975,498	$ 2,887	$ 5,773	$ (39,366)	$ 941,905
2	1 (LNG Plant - post Feb 2015)	4%	15,853	-	-	(634)	15,219
3	1(b)	6%	96,232	4,299	8,597	(6,548)	98,281
4	2	6%	86,873	-	-	(5,212)	81,661
5	3	5%	1,689	-	-	(84)	1,605
6	6	10%	265	-	-	(27)	238
7	7	15%	21,662	1,479	2,958	(3,915)	20,705
8	8	20%	27,302	4,600	9,200	(8,220)	28,282
9	10	30%	15,044	3,970	7,940	(8,086)	14,898
10	10.1	30%	185	-	-	(55)	130
11	12	100%	-	-	18,364	(18,364)	-
12	13	manual	2,196	-	-	(478)	1,718
13	14	manual	50	-	-	(25)	25
14	14.1 (pre 2017)	7%	16,398	-	-	(1,148)	15,250
15	14.1 (post 2016)	5%	5,595	-	-	(280)	5,315
16	17	8%	1,046	-	-	(84)	962
17	38	30%	2,143	-	-	(643)	1,500
18	43.2	50%	392	-	3,271	(3,467)	196
19	45	45%	2	-	-	(1)	1
20	47	8%	166,274	-	-	(13,302)	152,972
21	47 (LNG Plant - post Feb 2015)	8%	173,538	-	-	(13,883)	159,655
22	49	8%	369,314	54,875	109,749	(42,715)	436,348
23	50	55%	4,807	4,591	9,182	(10,219)	3,770
24	51	6%	1,416,788	95,284	190,569	(102,158)	1,505,199
25							
26	Total		$ 3,399,146	$ 171,985	$ 365,603	$ (278,914)	$ 3,485,835

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 26

Line No.	Particulars	2020 Projection Earned Return	2021 Amount	2021 Ratio	2021 Average Embedded Cost	2021 Cost Component	2021 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 141,614	$ 3,082,792	59.14%	4.78%	2.83%	$ 147,276	$ 5,662	Schedule 27, Line 30&32, Column 5&6&7
2	Short Term Debt	3,669	122,945	2.36%	2.19%	0.05%	2,692	(977)	
3	Common Equity	170,022	2,006,844	38.50%	8.75%	3.37%	175,599	5,577	
4									
5	Total	$ 315,305	$ 5,212,581	100.00%		6.25%	$ 325,567	$ 10,262	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(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	125,326	126,167	2.644%	3,336	
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	198,000	200,000	2.588%	5,176	
17	2021 Medium Term Debt Issue	July 1, 2021	July 1, 2051	198,000	100,822	3.353%	3,381	
18								
19	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
20	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
21								
22	LILO Obligations - Nelson	March 1, 2004	February 28, 2021		392	9.439%	37	
23	LILO Obligations - Prince George	October 31, 2004	October 31, 2021		15,705	9.615%	1,510	
24	LILO Obligations - Creston	November 1, 2005	October 31, 2022		1,823	8.338%	152	
25								
26	Vehicle Lease Obligation				427	2.576%	11	
27								
28	Sub-Total				$ 3,090,336		$ 147,636	
29	Less: Fort Nelson Division Portion of Long Term Debt				(7,544)		(360)	
30	Total				$ 3,082,792		$ 147,276	
31								
32	Average Embedded Cost					4.78%		
33								
34	* 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 its MRP (identifying one potential exogenous factor that affects 2020), emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI requests approval for the disposition of one existing deferral account and provides an update on another existing deferral account. FEI also 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 MRP. 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 MRP Decision.

The COVID-19 pandemic is a potential exogenous factor affecting 2020 and future years, as described below.

12.2.1 COVID-19 Pandemic

During the COVID-19 public health emergency, FEI has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its delivery system safely and reliably.

Any incremental O&M and capital impacts related to COVID-19 would meet the first three Exogenous Factor requirements based on the following:

- The COVID-19 pandemic is an event outside the control of a prudently operated utility.

- Costs to address COVID-19 were not included in the 2019 Base O&M expense or the forecast regular capital expenditures approved as part of the MRP and therefore the criterion that they be "outside the base upon which rates were originally derived" would be met.

- The COVID-19 pandemic started to have measurable impacts in mid-March 2020 in BC, and was unforeseen at the time of the close of evidence related to the MRP Application. The BCUC commented on COVID-19 in the MRP Decision[66], stating that the pandemic has raised questions about the validity of some fundamental assumptions underlying various elements of the MRPs. The BCUC concluded that the situation is fluid with many uncertainties and outcomes that are difficult to predict and manage in the circumstances and that the BCUC must adjudicate the merits of the MRP Application based on the evidence submitted. The BCUC also pointed to the Annual Review process and other safeguards such as exogenous factors as avenues that could provide relief to FEI and ratepayers should such relief become necessary.

For the remaining criteria - the determination of whether the amounts are directly related to COVID-19 and the prudency and materiality of costs - these determinations cannot be made until after the impacts of the exogenous factor are known.

To date in 2020, FEI has incurred incremental O&M expenditures for COVID-19 related items, including the following:

- cleaning and disinfecting of facilities to promote a safe work environment;

- activities to support appropriate social distancing in the work environment, such as expanded hours at the Willingdon Park contact centre; and

- Public Affairs Emergency communications activities to keep our customers informed of the assistance available during this challenging time.

FEI expects to continue to incur additional expenditures for the remainder of the year. Additionally, FEI is monitoring for any significant savings related to COVID-19 such as a temporary reduction in employee-related expenses that may help to offset the incremental expenditures. However, with the uncertainty regarding COVID-19's expected duration and impact (i.e., timing of transition to and from Phases 2, 3, and 4 of the Province's BC Restart Plan), FEI at this time is unable to provide a forecast of incremental impacts related to COVID-19 for 2020 or for future years.

Due to the uncertainty, FEI is not seeking approval of exogenous factor treatment for incremental impacts related to COVID-19 at this time. Instead, over the coming months, FEI will evaluate the COVID-19 incremental costs and related savings. If the incremental costs and

[66] MRP Decision, p. 170.

related savings are determined to be significant, FEI proposes to include the amounts in the previously approved COVID-19 Customer Recovery Fund Deferral Account. The amounts will then be reviewed in 2021 when actual 2020 amounts and forecasts for future years can be ascertained, and an appropriate recovery method can be determined.

12.3 *ACCOUNTING MATTERS*

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

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, 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." While this directive was not included as part of the MRP Decision, FEI will continue to provide accounting policy changes and updates as part of the Annual Review materials. FEI discusses one accounting matter below:

- Credit Losses - for Accounting Standards Update (ASU) 2016-13, *Measurement of Credit Losses on Financial Instruments*: The accounting assessment of this new standard is not expected to directly affect how FEI sets its revenue requirements or delivery rates, but some principles within the new guidance have been applied in the determination of forecasted unrecovered revenue for 2020 and 2021 to be captured in the COVID-19 Customer Recovery Fund Deferral Account.

12.3.1.1 Credit Losses

Effective January 1, 2020, FEI adopted ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimate of credit losses (also referred to as allowance for doubtful accounts) and the recognition of expected losses (also referred to as bad debt expense) upon initial recognition of a financial instrument, in addition to using past events and current conditions.

Consistent with prior accounting under US GAAP, FEI records an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. As a result of this ASU, the credit loss allowance is estimated by taking into account historical experience, current conditions, reasonable and supportable economic forecasts and accounts receivable aging. In addition to historical collection patterns, FEI considers customer class, customer size, economic indicators and certain other risk characteristics when evaluating the credit loss allowance.

ASU 2016-13 is not expected to change how FEI determines its revenue requirements for 2020 and 2021. However, since ASU 2016-13 provides entities with additional guidance on how to estimate future credit losses, some principles within the new guidance have been applied in the determination of forecasted unrecovered revenue for 2020 and 2021 to be captured in the COVID-19 Customer Recovery Fund Deferral Account. Details of this deferral account are provided in Section 7.5.2.1.

The focus of ASU 2016-13 is to develop a forward-looking provision for credit losses, or bad debt expense, at the beginning of the revenue cycle relying on broader principles and macroeconomic factors. The unrecovered revenue captured in the COVID-19 Customer Recovery Fund Deferral Account is intended to represent specific customer bad debt write-offs that occur potentially many months after initially being billed the revenue for consumption. Therefore, under US GAAP, FEI will recognize the initial credit loss expense against the deferral account explained in Section 7.5.2.1 with the offset against accounts receivable. This entry will only be applied for external financial reporting purposes and will not affect the deferral account or O&M for regulatory accounting purposes or setting delivery rates. Over the entire revenue, billing and collection cycle, the credit losses recognized under ASU 2016-13 will approximate the actual customer account write-offs.

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).

In the following sections, FEI requests disposition of one previously approved deferral account and provides information on the Transmission Integrity Management Capabilities (TIMC) Development Costs and Flow-through deferral accounts. Information on FEI's non-rate base earnings sharing and BVA deferral accounts is included in Section 10.

12.4.1 Existing Deferral Accounts

12.4.1.1 2017 & 2018 Revenue Surplus

As part of the Annual Review for 2017 Delivery Rates, FEI received approval through Order G-182-16 to establish the 2017 Revenue Surplus deferral account to capture the 2017 revenue surplus resulting from maintaining 2017 rates at existing 2016 levels. The forecasted 2017 revenue surplus amount to be recorded in this account was $32.012 million[67]. The account was approved to attract a WACC return.

In the Annual Review for 2018 Delivery Rates, FEI received approval through Order G-196-17 to change the name of the account to the 2017 & 2018 Revenue Surplus deferral account, and to record the 2018 forecasted surplus of $7.960 million in the deferral account. This amount was further amended through FEI's Compliance Filing to $5.398 million[68].

[67] Line 28, Schedule 1 of Appendix A Financial Schedules attached to the Annual Review for 2017 Rates Order G-182-16 Compliance Filing.
[68] Table 1 from FEI's January 19, 2018 Compliance Filing.

Including the 2017 and 2018 WACC return credit additions to the deferral account, the ending 2018 after-tax balance in the deferral account was a credit of $29.870 million[69].

In 2019, through Order G-30-19, FEI received approval to record the incremental 2019 pre-tax revenue deficiency of $355 thousand ($259 thousand after-tax) resulting from the impacts of the 2019-2022 DSM Application decision on 2019 permanent delivery rates, to the 2017 & 2018 Revenue Surplus deferral account. Including the 2019 WACC return credit additions of $1.725 million to the deferral account, the ending 2019 after-tax balance in the deferral account was a credit of $31.336 million.[70]

In this Application, FEI is requesting approval to draw down $10.338 million[71] pre-tax of the deferral account balance in 2020 rates, which will result in a total 2020 forecasted revenue deficiency of $16.300 million and a 2.0 percent delivery rate increase, maintaining 2020 permanent rates at interim levels.

FEI is also requesting approval to draw down the remaining balance of the deferral account in 2021 rates, which equals $35.287 million[72] pre-tax, which will result in a 6.59 percent 2021 delivery rate increase compared to 2020 delivery rates. Without returning a portion of the existing surplus in 2021, the 2021 delivery rate increase would be 10.87 percent compared to 2020 levels.

Including the 2020 and 2021 WACC return credit additions to the deferral account, the ending 2021 after-tax balance in the deferral account is forecasted to be zero.[73]

Table 12-1: 2017 & 2018 Revenue Surplus Deferral Account Continuity ($000s)

Description	Opening Balance	(Additions)/ Drawdowns	Taxes	AFUDC	Ending Balance
2017 Actuals	-	(32,012)	8,323	(732)	(24,421)
2018 Actuals	(24,421)	(5,398)	1,457	(1,509)	(29,870)
2019 Actuals	(29,870)	355	(96)	(1,725)	(31,336)
2020 Projected	(31,336)	10,338	(2,791)	(1,547)	(25,336)
2021 Forecast	(25,336)	35,287	(9,527)	(424)	-

12.4.1.2 Transmission Integrity Management Capabilities (TIMC) Development Costs

As indicated in the Annual Review for 2019 Delivery Rates, FEI has initiated the development of the TIMC project to enhance its capabilities for managing the hazards of stress corrosion cracking (SCC) and other crack-like imperfections on its transmission system. In-line inspection

69 (($32.012 million x (1-26%)) plus (($5.398 million x (1-27%)) plus $2.241 million WACC return = $29.870 million.
70 Section 11 - 2020, Schedule 12, Line 8, Column 2.
71 Section 11 - 2020, Schedule 12, Line 8, Column 4. Note the amount in the financial schedules also includes 2020 forecasted WACC return credit additions of $1.547 million.
72 Section 11 - 2021, Schedule 12, Line 8, Column 4. Note the amount in the financial schedules also includes 2021 forecasted WACC return credit additions of $0.424 million.
73 Section 11 - 2021, Schedule 12, Line 8, Column 9.

tools capable of detecting and sizing cracks are becoming sufficiently proven and commercialized such that FEI's consideration of higher-confidence methods for managing this hazard is now prudent and warranted.

FEI's baseline quantitative risk assessment (QRA) for its mainline transmission pipelines, to date, has provided an understanding of system risks and confirms SCC and crack-like hazards as risk drivers to pipelines within FEI's gas transmission system warranting mitigation. The QRA is further enabling the identification and prioritization of transmission lines for mitigation.

Where it is practical and cost effective to alter FEI's transmission system for EMAT in-line inspection, including capabilities for potential post-run operational responses (e.g. pressure reduction), FEI will seek to mitigate the risk of rupture failure due to SCC and other crack-like imperfections by adopting EMAT tools within its in-line inspection activity. Other potential mitigation alternatives, such as pipeline re-coating and/or pipeline replacement, will be proposed where ILI is not practical or cost effective.

In the decision accompanying Order G-237-18, which *inter alia* approved the creation of a non-rate base deferral account to collect development costs related to the TIMC project, FEI was directed to provide the following information:

1) Updated actual and forecast project development costs compared to budget with explanations for variances;

2) Updated timeline for when FEI anticipates filing the CPCN with explanations for changes; and

3) Details on project scope and deliverables, including any changes thereto from what was provided in the current annual review proceeding.

In compliance with this directive, FEI provides the following project update.

Project Development Costs

Following is an update to Table 12-1 from the FEI Annual Review for 2019 Delivery Rates, which shows the original forecast and updated actual costs for the TIMC project up to the end of June 2020.

Table 12-2: TIMC CPCN Development Costs ($000s)

Line		2018		2019		2020 (YTD)		Total (YTD)	
No.		Forecast	Actuals	Forecast	Actuals	Forecast	Actuals	Forecast	Actuals
1	Phase 1	5,680	4,794	5,710	5,484	230	274	11,620	10,552
2	Phase 2	0	0	19,000	6,016	11,000	1,448	30,000	7,464
3									
4	Total	**5,680**	**4,794**	**24,710**	**11,500**	**11,230**	**1,722**	**41,620**	**18,016**

The completed Phase 1 actual costs vary from forecast primarily due to fewer than expected critical data gaps to complete FEI's baseline QRA, as well as reduced allocation of FEI internal staff time associated with TIMC Phase 1. While FEI expects to address various data issues for subsequent iterations of risk assessments, FEI is achieving its baseline QRA objectives with reduced field data collection from what was originally forecast. Although FEI internal staff have been required to advance Phase 1 work, backfilling of regular duties has not been occurring to the extent originally forecast. Where regular duties are not backfilled, FEI internal staff time is not allocated to the TIMC project.

In the Annual Review for 2019 Delivery Rates, FEI indicated that the Phase 2 costs had a high degree of uncertainty. FEI has determined that alterations to the transmission system will require significant capital investment over multiple years, and scope of work identification and development is complex. To date, two future CPCN applications based on risk, scope, and complexity of the required alterations are in development: TIMC 1 and TIMC 2.

Phase 2 actual costs vary significantly from forecast primarily due to costs being incurred later than originally forecast. Total Phase 2 costs continue to have a high degree of uncertainty due to the current status of scope development. FEI will provide a more detailed breakdown of costs for both TIMC 1 and 2 in the upcoming TIMC 1 CPCN application. At this time, FEI expects the costs to complete the remaining development work to remain at or below the previously proposed deferral account forecast.

Timeline

FEI expects to file its TIMC 1 CPCN application by early 2021. This represents an approximate six-month change to the mid-2020 filing schedule originally proposed in the FEI Annual Review for 2019 Delivery Rates, which requested creation of the deferral account, and reaffirmed in IR responses to the MRP Application.

Due to complexities associated with scope of work identification and development, FEI is developing a TIMC 2 application, expected to be filed by early 2022, and is continuing to assess other needed alterations to ensure long-term transmission system integrity.

Scope and Deliverables

TIMC 1

TIMC 1 consists of FEI pipelines identified as warranting SCC mitigation, and which have sufficient available delivery capacity to accommodate the use of EMAT tools. Although TIMC 1 pipelines require alteration to establish the capability to reduce their operating pressure for extended periods, they will not require pipeline looping to control flow rates or maintain delivery capacity during these potential operating pressure reductions.

FEI has begun front end engineering and design (FEED) work to further define the scopes and estimates for the identified pipeline risk mitigation projects.

TIMC 1 has three components:

1. Completion of a baseline QRA to validate the risks posed by SCC and other cracking hazards, and the lines which require mitigation for these hazards;
2. Provision of capabilities for ongoing quantitative risk management (including QRAs) of FEI's BC Oil and Gas Commission-regulated pipelines; and
3. Development of individual scopes, estimates, and other project deliverables associated with necessary alterations for 11 transmission lines in FEI's Coastal Transmission System to support the use of EMAT in-line inspection tools or other cost-effective crack mitigation alternatives (as appropriate).

The above scope and deliverables remain consistent with that proposed in the original request that proposed creation of the deferral account. In that request, these items were characterized as the Phase 1 and Phase 2 portions of the TIMC CPCN application.

TIMC 2

TIMC 2 consists of alterations to FEI's Interior Transmission System (ITS) pipelines to allow for the passage of EMAT in-line inspection tools in eight pipelines. These pipelines are flow and capacity constrained, and options for relieving these constraints are being evaluated. The scope is under development and refinement; however, it is foreseeable that pipeline looping will be required to establish the capability to reduce the operating pressure of these pipelines for extended time periods while still maintaining sufficient flow to meet customer peak demands.

As already noted, due to the complexity of the work associated with FEI's ITS pipelines, these pipelines are being included in the TIMC 2 portion of the project. Note that this does not represent a change from the original scope, but rather one of timing for execution of these project components.

12.4.1.3 Flow-Through Deferral Account (2020-2024)

As approved through Order G-165-20, 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 C4-1 of the MRP Application, reproduced below.

Table 12-3: 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 net of PSI	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
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
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 variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	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, biomethane, variable LNG production, integrity digs and EV charging stations.

2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV 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

FEI has included a discussion on the final amounts accumulated in the Flow-through deferral account during the 2014-2019 PBR Plan term, including the related 2020 financing and amortization, in Section 14 of this Application.

Similar to the discussion in Section 10.1 on FEI's 2020 Projected earnings sharing amount, FEI is not projecting a Flow-through balance for 2020. This is because FEI has included actual amounts up until June 30, 2020 within its Projected 2020 revenue requirement throughout this Application and is not projecting any further variances for the remainder of the year from the amounts included in this Application. Therefore, there are no amounts to include within the 2020 Flow-through projection.

An adjustment to include the difference between the projected amount of zero[74] and final actual amounts for 2020 subject to flow-through will be recorded in the deferral account in 2021 and amortized in 2022 rates.

12.5 *SUMMARY*

FEI has discussed one new exogenous factor that may affect delivery rates in 2021, has provided an update on certain accounting related matters, requested approval for the disposition of one existing deferral account, and included information on the TIMC Development Costs and Flow-through deferral accounts.

[74] Section 11 - 2020, Schedule 12, Line 3, Column 4.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

Under the MRP, SQIs are used to monitor the Utility'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 MRP Decision and Order G-165-20, the BCUC approved a balanced set of SQIs for FEI, covering safety, responsiveness to customer needs and reliability. Nine of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

The BCUC has determined that the process used during the 2014-2019 PBR Plan to interpret metric performance will remain in effect for the MRP[75]. Consistent with the BCUC's direction issued in its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing, FEI will review service quality for a year in the following year's annual review. As 2019 SQI results pertain to the 2014-2019 PBR Plan, they are discussed separately in Section 14.

In the subsections below, FEI reports on its June 2020 year-to-date performance as measured against the SQI benchmarks and thresholds. The June 2020 year-to-date SQI results indicate that the Company's overall performance to date meets service quality requirements. For the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one, Meter Reading Accuracy, lower than the benchmark and threshold due to the impact of COVID-19.[76] For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term, FEI has provided year-to-date 2020 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FEI's actual 2020 SQI performance in the Annual Review for 2022 Delivery Rates when actual SQI results are known. FEI also notes that it will provide information on the 2021 year-to-date SQI results in the Annual Review for 2022 Delivery Rates.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's June year-to-date performance for 2020 to the proposed benchmarks and thresholds as part of the MRP. Actual June year-to-date results for 2020 are also provided for the four informational SQIs.

[75] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs".

[76] In Letter L-20-20, dated March 31, 2020, the BCUC granted public utilities relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.

1 **Table 13-1: SQI Benchmarks and Actual Performance**

Performance Measure	Description	Benchmark	Threshold	2020 June YTD
Safety SQIs				
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	98.0%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	97.3%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<= 2.08	2.95	1.42
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 8	12	6
Responsiveness to the Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	82%[77]
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	0.51
Meter Reading Accuracy	Number of scheduled meters that were read	>= 95%	92%	88%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	76%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	97.6%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.6
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	41
Reliability SQIs				
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	0

[77] First Contact Resolution surveying was suspended from Mar 23 - May 3 2020 as a result of the COVID-19 pandemic, thus the YTD figure does not contain data for the period that surveys were suspended.

Performance Measure	Description	Benchmark	Threshold	2020 June YTD
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0030

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2020. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

This SQI measures the utility's responsiveness to on average 25,000 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 June 2020 year-to-date performance is 98 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan and the 2020 June year-to-date emergency response time results are provided below.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Results	96.7%	97.3%	97.4%	97.8%	97.8%	97.9%	98.0%
Benchmark	97.7%	97.7%	97.7%	97.7%	97.7%	97.7%	97.7%
Threshold	96.2%	96.2%	96.2%	96.2%	96.2%	96.2%	96.2%

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 June 2020 year-to-date performance is 97.3 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014 to 2019 PBR Plan and the 2020 June year-to-date for TSF (Emergency) are provided below:

Table 13-3: Historical TSF (Emergency) Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Results	95.8%	97.6%	98.5%	97.6%	97.9%	97.2%	97.3%
Benchmark	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Threshold	92.8%	92.8%	92.8%	92.8%	92.8%	92.8%	92.8%

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 June 2020 year-to-date performance (three-year rolling average) result is 1.42, which is better than the benchmark. The 2020 year-to-date performance reflects 2 Medical Treatments and 4 Lost Time Injuries.

Safety continues to be a core value for FEI and prevention of injury remains a key focus. FEI continues to focus on and reinforce the fundamentals of safety through effective safe work planning, identifying hazards and mitigating risks, detailed work observations, and thorough event analysis capturing learnings and identifying opportunities for continued improvement.

For comparison, the Company's 2014 to 2019 and 2020 year-to-date AIFR results are provided below.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	1.73	2.52	2.13	1.36	1.74	1.82	0.70
Three year rolling average	2.22	2.42	2.13	2.00	1.74	1.64	1.42
Benchmark	2.08	2.08	2.08	2.08	2.08	2.08	2.08
Threshold	2.95	2.95	2.95	2.95	2.95	2.95	2.95

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. The new benchmark and threshold recently approved in the MRP are 8 and 12, respectively.

In its Decision on FEI's Application for the 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 June 2020 year-to-date performance is 6, which is 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 One 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 implementation of a Damage Investigation Program and predictive analytics have contributed to the improved performance.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below. The annual result has been trending downward. This is due to the historical upward trend in BC One Calls (increased awareness and increased construction activity) up until 2018, which was offset by an increase in the number of line damages resulting from increased construction activities. The Company has taken steps to address the upward trend in line damages. FEI has hired Damage Prevention Investigators to focus on repeat damagers, implemented predictive analytics to help identify high damage risk areas, and is working with Technical Safety BC to reduce line hits. While BC One Call ticket volume decreased in 2019 and YTD 2020, mainly due to efficiency gains realized through new software introduced by BC One call, line damages have also decreased.

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

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	9	8	8	9	8	7	6
Benchmark	16	16	16	16	16	16	8
Threshold	16	16	16	16	16	16	12
Calls to BC One Call	107,509	122,627	129,645	146,868	157,708	144,413	72,034
Line Damages	954	1,035	1,086	1,247	1,201	1,069	430

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

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 June 2020 year-to-date performance is 82 percent. This result excludes surveys from March 23 to May 3, 2020, as all Service Quality Measurement (SQM) surveys were suspended during that time due to the COVID-19 pandemic.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-6: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	80%	81%	81%	80%	83%	81%	82%
Benchmark	78%	78%	78%	78%	78%	78%	78%
Threshold	74%	74%	74%	74%	74%	74%	74%

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 five 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 2020 year-to-date result is 0.51, which is better than the benchmark of 3.0. No significant billing issues have arisen in 2020 so far.

The 2020 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2020 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%	100.00%	If (PA≥99.9%,5000*(1 - PA),1.05-PA))	=5000*(1-1)	0
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	98.34%	(100%-PA)*100	=(100%-98.34%)*100	1.66
Billing Service Quality Indicator; Target < 3		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0+0+1.66) /3	0.55

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-8: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	0.89	1.06	0.57	0.75	2.63	0.44	0.51
Benchmark	5.0	5.0	5.0	5.0	5.0	5.0	3.0
Threshold	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Meter Reading Accuracy

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 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.

The 2020 year-to-date result is 87.6 percent, which is lower than the benchmark and the threshold. The impact of COVID-19 and the need for physical distancing and enhanced hygiene practices by meter readers has resulted in a larger percentage of estimated reads. The BCUC anticipated this impact in Letter L-20-20, which granted public utilities relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.[78]

FEI continues to work closely with its meter reading service provider, Olameter, to achieve as many actual meter reads as safely possible during the pandemic. In addition to using the best available historical billing information to estimate reads for billing purposes, FEI is working with

[78] In BCUC Letter L-20-20, dated March 31, 2020, the BCUC stated:

The BCUC recognizes that this Pandemic greatly impacts utilities and utility customers across British Columbia as many businesses and individuals adjust to working from home, social distancing, and self-isolation. Given these difficult circumstances, the BCUC understands that utilities may not be able to conduct in-person meter reading for all customers at this time due to safety and operational concerns. As such, any public utilities regulated by the British Columbia Utilities Commission (BCUC) that are unable to estimate billings within their endorsed tariff Terms and Conditions are granted relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.

In place of meter readings, when necessary, energy consumption may be estimated from best available sources and evidence for billing purposes. When the next actual meter reading is completed, customers' bills must then be adjusted for the difference between estimated and actual use over the interval between meter readings.

some customers to acquire additional information to support minimizing the variance between estimated and actual reads.[79]

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-9: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	97.0%	97.5%	96.9%	96.2%	95.4%	95.2%	87.6%
Benchmark	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Threshold	92.0%	92.0%	92.0%	92.0%	92.0%	92.0%	92.0%

Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 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 in order 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 June 2020 year-to-date performance is 76 percent, which is better than the benchmark. The increase in the service level observed to date in 2020 is due to reduced activities experienced since late March 2020, which is primarily the result of lower collection activities as part of our COVID-19 response. The service level is expected to be closer to the benchmark the remainder of the year when collection activities resume.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below. The 2014 result was achieved with the Company targeting 75 percent as the benchmark. The BCUC approved the revised target of 70 percent in mid-September 2014. In 2015 and subsequent years, actual results were reflective of the revised target of 70 percent.

[79] For example, where capacity is available, FEI is proactively contacting customers with multiple estimates in a row to determine if a customer provided read is possible to support the estimation.

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

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	75%	71%	71%	71%	71%	71%	76%
Benchmark[80]	75%	70%	70%	70%	70%	70%	70%
Threshold	68%	68%	68%	68%	68%	68%	68%

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 process improvements, number of emergencies, weather and traffic conditions. The process improvements initiated in recent years have resulted in the contact center and operations departments working more closely together in order to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The June 2020 year-to-date performance is 97.6 percent, which is better than the benchmark.[81]

The Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	95.5%	96.6%	96.9%	97.0%	96.3%	96.0%	97.6%
Benchmark	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Threshold	93.8%	93.8%	93.8%	93.8%	93.8%	93.8%	93.8%

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 the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential

[80] The 2014 result was achieved with the Company targeting 75 percent as the benchmark. The BCUC approved the revised target of 70 percent in mid-September 2014. In 2015 and subsequent years, actual results were reflective of the revised target of 70 percent.

[81] The Meter Exchange program was suspended in April and May due to the COVID-19 pandemic with limited resumption of meter exchange activities in June.

and mass market commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The average index score is 8.6, slightly lower than the 8.7 for the same period last year. Of the five measures that make up the overall customer satisfaction score, the results for June 2020 to date were lower in four and static in one when compared to June 2019 to date performance. The scores for overall satisfaction and for accuracy of meter reading decreased from 8.7 to 8.6 and 8.5 to 8.4, respectively. June year-to-date ratings for the energy conservation information and contact centre metrics decreased from 7.9 to 7.8 and 9.0 to 8.4, respectively. Satisfaction with field services remained static at 9.0.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	8.5	8.6	8.8	8.4	8.7	8.7	8.6
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a

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 June 2020 year-to-date result of 41 seconds is consistent with prior years' results.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-13: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	34	37	40	34	35	39	41
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a

13.2.3 Reliability Service Quality Indicators

Transmission Reportable Incidents

The Transmission Reportable Incidents metric, an informational indicator as approved by the BCUC, measures the number of reportable incidents to outside agencies for transmission assets as defined by the Oil and Gas Commission (OGC). The metric is intended to be an indicator of the integrity of the transmission system.

For comparison, the Company's 2014 to 2019 historical annual and 2020 year-to-date results by severity levels are provided below.

Table 13-14: Historical Transmission Reportable Incidents

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results – Level 1	1	3	3	4	2	0	0
Annual Results – Level 2	1	0	0	0	0	0	0
Annual Results – Level 3	0	0	0	0	0	0	0
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator approved by the BCUC 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. Increases in leak survey activity levels will generally also result in a higher number of leaks detected.

In its Decision on FEI's Application for the Annual Review of 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 2020 year-to-date five-year rolling average result of 0.0053 calculated using data from July 2015 to June 2020.

Table 13-15: June 2020 Year-to-Date Five Year Rolling Average

Period	Metric
July – December 2015	0.0019
January – December 2016	0.0047
January – December 2017	0.0047
January – December 2018	0.0060
January – December 2019	0.0061
January – June 2020	0.0030
Five Year Rolling Average	0.0053

The Company's 2014 to 2019 annual 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 2017 five-year average is calculated using 2013 to 2017 annual data). The June 2020 year-to-date result is 0.0030, which is based on 70 leaks detected year-to-date, as compared to 69 in 2018 and 70 in 2019 for a similar time period.

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

Leaks per KM of Distribution System Mains	2014	2015	2016	2017	2018	2019	June 2020 YTD
Leaks	114	102	107	108	140	139	70
Total km	19,172	22,602	22,813	22,951	23,060	23,268	23,460
Leaks per km	0.0059	0.0045	0.0047	0.0047	0.0061	0.0060	0.0030
5 year average	0.0077	0.0071	0.0063	0.0055	.0052	.0051	0.0053

13.3 *SUMMARY*

In summary, FEI's June 2020 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. At the end of June 2020, for those SQIs with benchmarks, eight performed at or better than the approved benchmarks with one SQI, Meter Reading Accuracy, impacted by COVID-19. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

14. PBR ELEMENTS

14.1 *INTRODUCTION AND OVERVIEW*

The setting of rates for 2020 includes elements related to the conclusion of the 2014-2019 PBR Plan, which are discussed in this section. Calculations for the true-up of rate base, 2019 Flow-through account, Earnings Sharing Mechanism, and Service Quality Indicator results, are included in this section.

14.2 *TRUE-UP OF PBR PLAN RATE BASE*

During the term of the 2014-2019 PBR Plan, capital expenditures in excess of formula but within the defined dead band (10 percent on an annual basis, or 15 percent on a two-year basis) were excluded from rate base. For FEI, the cumulative amount of capital excluded from rate base was $65.006 million (Table 14-3, Line 38, Column 2). As provided in the 2014-2019 PBR Plan, this amount is added to plant in service effective January 1, 2020.

Also included in the January 1, 2020 adjustment to plant in service is the $61.082 million in 2019 expenditures that exceeded the dead band (Table 14-3, Line 35, Column 8). Under the 2014-2019 PBR Plan, expenditures outside of the dead band enter rate base on January 1 of the following year. The total adjustment to plant in service at January 2020 is therefore $126.088 million ($65.006 million plus $61.082 million) as shown in Section 11 – 2020, Schedule 6.2, Line 35, Column 4.

Correspondingly, depreciation expense reflects the aforementioned adjustments to 2020 opening plant.

14.3 *2019 FLOW-THROUGH ACCOUNT*

As approved by Order G-162-14, the Flow-through deferral account is used to capture the annual variances during the 2014-2019 PBR Plan term between the approved and actual amounts for all costs and revenues which are included in rates on a forecast basis and which do not have a previously approved deferral account.

The final amount to be distributed to customers in 2020 is a credit of $36.392 million (after tax) and is comprised of the following:

- A net variance between approved and actual of $22.243 million (credit) in flow-through items for 2019. The variance is primarily the result of higher delivery margin revenue, lower income taxes and lower depreciation expense, partially offset by higher flow-through O&M expenses;
- A true-up to actual of $11.617 million (credit) to the projected ending 2018 Flow-through account balance, resulting from higher delivery margin revenue and lower depreciation

expense. The $11.617 million credit is the difference between the projected ending 2018 Flow-through deferral account balance embedded in 2019 delivery rates of $24.478 million[82] (credit) and the actual ending 2018 deferral account balance of $36.095 million (credit);

- The associated 2019 financing adjustment of $1.390 million (credit) related to the difference between the actual 2019 financing credit of $2.058 million and the $0.668 million[83] financing credit embedded in 2019 delivery rates; and
- A 2020 forecast financing amount of $1.142 million (credit).[84]

The total of the amounts above result in a return to customers of $36.392 million (after tax) in 2020, as shown in the non-rate base deferral section of the financial schedules in Section 11 - 2020, Schedule 12 and in Table 14-1 below.

[82] Annual Review for 2019 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 2.
[83] Annual Review for 2019 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 4.
[84] Section 11 - 2020, Schedule 12, Line 4, Column 4.

Table 14-1: 2019 Flow-Through Deferral Account Additions ($ millions)

Line No.	Particulars	2019 Approved	2019 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	Delivery Margin			
2	Residential (Rate 1)	$ (491.826)	$ (495.069)	$ (3.243)
3	Commercial (Rate 2, 3, 23)	(238.980)	(244.667)	(5.687)
4	Industrial (All Others)	(113.352)	(115.929)	(2.578)
5	Total Delivery Margin	(844.157)	(855.665)	(11.508)
6				
7	O&M Tracked outside of Formula			
8	Insurance	5.473	6.294	0.821
9	Bio-Methane	1.369	1.205	(0.164)
10	Bio-Methane O&M transferred to BVA	(1.322)	(1.149)	0.173
11	NGT O&M	2.339	2.060	(0.279)
12	LNG Production O&M	7.432	10.846	3.414
13	MSP Reduction	(0.829)	(0.801)	0.028
14	Employer Health Tax	2.630	2.894	0.264
15				
16	Property and Sundry Taxes	67.559	67.781	0.222
17				
18	Depreciation and Amortization	230.699	226.450	(4.249)
19				
20	Other Operating Revenue	(44.893)	(44.546)	0.347
21				
22	Interest Expense	140.241	139.880	(0.361)
23				
24	Income Taxes	52.972	42.021	(10.951)
25				
26	2019 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)			(22.243)
27				
28	2018 Ending Deferral Account Balance True-up			(11.617)
29	2019 Financing True-up			(1.390)
30	2020 Financing Addition to Deferral Account			(1.142)
31				
32	2020 After-Tax Amortization			(36.392)

14.4 *EARNINGS SHARING*

For 2020, FEI is proposing to recover through rates a $1.653 million pre-tax debit ($1.206 million[85] after tax) as shown in Table 14-2 below. This amount is comprised of:

- 2019 actual sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth in 2018;
- An adjustment for actual customer growth in 2019;
- The true-up of the 2018 projected earnings sharing to actual; and
- Financing on the deferral account balance.

85 Section 11 - 2020, Schedule 12, Line 22, Column 6.

Table 14-2: Summary of Earnings Sharing to be Recovered in 2020 ($ millions)

Line No.	Particulars	After-tax Amount	Reference
1	2019 Actual Sharing	0.601	Table 14-3, Line 54
2	2018 Actual Customer Growth adjustment	0.134	Table 14-4, Line 34
3	2019 Actual Customer Growth adjustment	0.019	Table 14-5, Line 34
4	2019 Actual Customer Growth adjustment O&M	(0.024)	Table 14-5, Line 43
5	2018 Projected vs. Actual ending balance true-up	0.452	Table 14-6, Line 3
6	Financing	0.022	Table 14-7, Line 5
7			
8	**2020 after-tax amount collected from customers**	**1.206**	
9	**2020 pre-tax amount collected from customers**	**1.653**	Line 8 / 0.73

Each of these items is discussed in the sections below.

14.4.1 2019 Earnings Sharing

As set out in FEI's letter dated November 7, 2014 in response to Order G-162-14 and as approved by Order G-86-15 for FEI's Annual Review for 2015 Rates, the earnings sharing is calculated each year as one-half of the pre-tax earnings impact of the variances in the formula-driven gross O&M and cumulative capital expenditures, as follows:

> Formula-driven O&M less actual base O&M[86] x 50% +
>
> ((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[87]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

In 2019, FEI achieved formula-driven O&M savings of $1.352 million, and 2019 capital expenditures exceeded the formula by $76.971 million. The $76.971 million excess 2019 capital expenditures exceeded the dead band by $61.082 million; therefore, FEI has removed the $61.082 million amount above the dead band in the calculation of 2019 earnings sharing, as shown in Line 35 of Table 14-3 below.

[86] Excluding items that are reforecast outside of the formula.
[87] Ibid.

Table 14-3: Calculation of 2019 Earnings Sharing ($ millions)

Line No.	Particulars								Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Approved Formula O&M	248.939							G-237-18 & G-10-19
2									
3	Actual Gross O&M	283.880							
4	Less: O&M Tracked outside of Formula								
5	Pension/OPEB (O&M portion)	13.795							
6	Insurance	6.294							
7	Biomethane	1.205							
8	NGT O&M	2.060							
9	RS 16/46 O&M	10.846							
10	MSP	(0.801)							
11	EHT	2.894							
12	Total	36.293							Sum of Lines 5 through 11
13									
14	Actual/Projected Base O&M	247.587							Line 3 - Line 12
15									
16	O&M Subject to Sharing	(1.352)							Line 14 - Line 1
17									
18			Annual Capital Expenditures						
19		Cumulative	2014	2015	2016	2017	2018	2019	Note 1
20									
21	Formula CapEx	860.438	119.821	139.380	145.315	146.581	152.082	157.259	
22									
23	Total Regular CapEx	1,216.520	144.932	174.489	182.976	214.793	247.078	252.252	
24	Less: CapEx tracked outside of formula								
25	Pension and OPEB	21.669	3.915	4.324	4.075	2.663	3.127	3.565	
26	Biomethane	7.841	3.656	1.350	1.346	0.965	0.045	0.480	
27	NGT	24.738	5.816	5.607	5.797	2.134	1.730	3.654	
28	CIAC	35.522	4.419	6.336	6.309	6.880	5.560	6.018	
29	AFUDC	20.018	2.727	3.293	3.309	3.193	3.572	3.924	
30	MSP	(0.291)	-	-	-	-	(0.144)	(0.146)	
31	EHT	0.529	-	-	-	-	-	0.529	
32	Total	110.027	20.533	20.911	20.836	15.835	13.889	18.022	Sum of Lines 25 through 31
33									
34	Actual/Projected Base CapEx	1,106.493	124.399	153.578	162.140	198.958	233.189	234.230	Line 23 - Line 32
35	Dead Band Adjustment	(181.049)		-	(9.176)	(37.632)	(73.160)	(61.082)	Adjustment to stay within deadband
36	Actual/Projected Base CapEx for ESM Calculation	925.444	124.399	153.578	152.964	161.326	160.029	173.148	Line 34 + Line 35
37									
38	Actual/Projected Cumulative Base CapEx Variance	65.006	4.578	14.198	7.649	14.745	7.947	15.889	Line 36 - Line 21
39									
40	Single Year Deadband % Variance (after adjustment)		3.70%	9.88%	5.12%	9.88%	5.12%	9.88%	Line 38 / (Line 21 + Line 25)
41	Two year Cumulative Deadband % Variance (after adjustment)			13.58%	15.00%	15.00%	15.00%	15.00%	Line 40 sum of two years
42									
43	Equity Component of Rate Base	38.5%							
44	Approved Return on Equity	8.75%							
45	After Tax Return on CapEx Subject to Sharing	2.190							Product of Lines 38, 43 & 44
46	Tax Rate	27.0%							
47									
48	Before Tax Return on CapEx Subject to Sharing	3.000							Line 45 / (1 - Line 46)
49									
50	Total before tax Sharing Amount	1.648							Line 16 + Line 48
51	Sharing percentage	50%							G-138-14
52									
53	2019 Actual Earnings Sharing (pre-tax)	0.824							Line 50 x Line 51
54	2019 Actual Earnings Sharing (after-tax)	0.601							Line 53 x 0.73

Notes
1 Actual results from BCUC Annual Report

14.4.2 Actual Customer Growth Adjustment

As set out in Order G-15-15 in relation to formula capital expenditures:

> FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the

> actual customer additions. This positive or negative variance in earned return resulting from the Growth Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism.

Additionally, also as set out in Order G-15-15 in relation to formula O&M expenditures:

> At the end of the PBR term, or any subsequent extension to the PBR term, FEI and FBC are approved to adjust the earnings sharing calculation for the last year of the PBR term to account for the actual growth in the last year of the PBR term.

Based on its actual customer additions, FEI has calculated the resulting adjustments of $0.184 million debit ($0.134 million debit after tax) for 2018 capital expenditures, $0.026 million debit ($0.019 million debit after tax) for 2019 capital expenditures, and $0.032 million credit ($0.024 million credit after tax) for 2019 O&M expenditures as shown in Tables 14-4 and 14-5 below.

Table 14-4: Calculation of Earnings Sharing Adjustment for 2018 Actual Customer Growth ($ millions)

Line No.	Particulars	$ millions	Reference
1	Average Customers 2018	1,016,353	
2	Average Customers 2017	997,380	
3	Growth in Average Customers	18,973	Line 1 - Line 2
4	Average Customer Growth	1.902%	Line 3 / Line 2
5		50%	G-138-14
6	Average Customer Growth to be recast in Formula	0.951%	Line 4 x Line 5
7	2018 Net Inflation Factor	0.601%	G-196-17 Compliance filing, Section 11, Schedule 3, Line 9, Column 7
8	2017 Reforecast Sustainment/Other Capital	$ 115.207	Note 1
9	2018 Reforecast Formulaic Sustainment/Other Capital	$ 117.002	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2018 Year Formulaic Sustainment/Other Capital	114.597	G-196-17 Compliance filing, Section 11, Schedule 4, Line 24, Column 3
11	Sustainment/Other Capital Increase from actual growth	$ 2.405	Line 9 - Line 10
12			
13			
14	Service Line Additions 2018	16,606	
15	Service Line Additions 2017	15,860	
16	Growth in Average Customers	746	Line 14 - Line 15
17	Average Customer Growth	4.70%	Line 16 / Line 15
18		50%	G-138-14
19	Average Customer Growth used in Formula	2.35%	Line 18 x Line 17
20	2017 Reforecast Service Line Additions	13,230	2019 Annual Review of Rates Table 10-3, Line 21
21	2018 ReForecast Service Line Additions	13,541	Line 20 x (1 + Line 19)
22	Service Line Addition Cost per Customer ($)	3,012	
23	2018 Reforecast Formulaic Growth Capital	$ 40.791	Line 21 x Line 22 / 1000000
24	2018 Formulaic Growth Capital	37.485	G-196-17 Compliance filing, Section 11, Schedule 4, Line 24, Column 2
25	Growth Capital Increase from actual growth	$ 3.306	Line 23 - Line 24
26			
27			
28	Increase in Capital Requirements from Actual Growth	$ 5.712	Line 11 + Line 25
29	Mid Year	$ 2.856	Line 28 / 2
30			
31	Equity Cost Component	3.37%	G-196.17
32	Debt Cost Component	3.08%	G-196-17
33	Earned Return on incremental Capital Requirements (pre-tax)	$ 0.184	Line 29 x (Line 31 + Line 32)
34	Earned Return on incremental Capital Requirements (after-tax)	$ 0.134	Line 33 x 0.73

Notes

1 2019 Annual Review for Rates Table 10-3, Line 9

Table 14-5: Calculation of Earnings Sharing Adjustment for 2019 Actual Customer Growth ($ millions)

Line No.	Particulars	$ millions	Reference
1	Average Customers 2019	1,031,862	
2	Average Customers 2018	1,016,353	
3	Growth in Average Customers	15,509	Line 1 - Line 2
4	Average Customer Growth	1.526%	Line 3 / Line 2
5		50%	G-138-14
6	Average Customer Growth to be recast in Formula	0.763%	Line 4 x Line 5
7	2019 Net Inflation Factor	1.411%	G-237-18 Compliance filing, Section 11, Schedule 3, Line 9, Column 7
8	2018 Reforecast Sustainment/Other Capital	$ 117.002	Note 1
9	2019 Reforecast Formulaic Sustainment/Other Capital	$ 119.558	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2019 Year Formulaic Sustainment/Other Capital	117.116	G-237-18 Compliance filing, Section 11, Schedule 4, Line 27, Column 3
11	Sustainment/Other Capital Increase from actual growth	$ 2.442	Line 9 - Line 10
12			
13			
14	Service Line Additions 2019	14,308	
15	Service Line Additions 2018	16,606	
16	Growth in Average Customers	(2,298)	Line 14 - Line 15
17	Average Customer Growth	-13.84%	Line 16 / Line 15
18		50%	G-138-14
19	Average Customer Growth used in Formula	-6.92%	Line 18 x Line 17
20	2018 Reforecast Service Line Additions	13,541	Table 10-3_2018, Line 21
21	2019 ReForecast Service Line Additions	12,604	Line 20 x (1 + Line 19)
22	Service Line Addition Cost per Customer ($)	3,055	
23	2019 Reforecast Formulaic Growth Capital	$ 38.505	Line 21 x Line 22 / 1000000
24	2019 Formulaic Growth Capital	40.143	G-237-18 Compliance filing, Section 11, Schedule 4, Line 27, Column 2
25	Growth Capital Increase from actual growth	$ (1.638)	Line 23 - Line 24
26			
27			
28	Increase in Capital Requirements from Actual Growth	$ 0.804	Line 11 + Line 25
29	Mid Year	$ 0.402	Line 28 / 2
30			
31	Equity Cost Component	3.37%	G-237-18
32	Debt Cost Component	3.13%	G-237-18
33	Earned Return on incremental Capital Requirements (pre-tax)	$ 0.026	Line 29 x (Line 31 + Line 32)
34	Earned Return on incremental Capital Requirements (after-tax)	$ 0.019	Line 33 x 0.73
35			
36			
37	Average Customer Growth to be recast in Formula	0.763%	Line 6
38	2019 Net Inflation Factor	1.411%	Line 7
39	2018 Formula O&M	$ 243.585	G-237-18 Compliance filing, Section 11, Schedule 20, Line 26, Column 2
40	2019 Reforecast O&M	$ 248.907	Line 39 x (1 + Line 38) x (1 + Line 37)
41	2019 Formulaic O&M	248.939	G-237-18 Compliance filing, Section 11, Schedule 20, Line 29, Column 2
42	2019 O&M difference from Actual Customer Growth (pre-tax)	$ (0.032)	Line 40 - Line 41
43	2019 O&M difference from Actual Customer Growth (after-tax)	$ (0.024)	Line 42 x 0.73

Notes

1 Table 14-4_2018, Line 9

14.4.3 True-Up for 2018 Actual Earnings Sharing

In FEI's 2018 Annual Report to the BCUC, FEI calculated the final 2018 earnings sharing based on the final 2018 results. The final amount of earnings sharing for 2018 was $0.975 million, which was $0.452 million lower than the $1.427 million projected for 2018, as shown in Table 14-6 below. As a result, FEI is recovering the 2018 earnings sharing variance between the projected and actual amounts of $0.452 million (after tax) in 2020 rates.

Table 14-6: Calculation of 2018 Actual Earnings Sharing true-up ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2018 Actual Earnings Sharing account ending balance	(0.975)	2018 FEI BCUC Annual Report
2	2018 Projected Earnings Sharing account ending balance	(1.427)	Annual Review of 2019 Rates Compliance Filing financial schedules, Schedule 12, Line 19, Column 2
3	**2018 Earnings Sharing account true-up**	**0.452**	

14.4.4 Financing

FEI has calculated the financing on the deferral account balances that result from the amounts described above. As shown in Table 14-7 below, FEI has calculated a $0.015 million credit to true-up for 2019 projected financing and a forecasted $0.037 million debit for 2020 financing. This results in a total after-tax financing adjustment of $0.022 million debit to be recovered from customers in 2020 rates, as shown in Tables 14-2 and 14-7.

Table 14-7: Calculation of Earnings Sharing Financing ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2019 Actual Earnings Sharing financing	(0.054)	2019 FEI BCUC Annual Report
2	Less: 2019 Forecasted Earnings Sharing financing	(0.039)	Annual Review of 2019 Rates Compliance Filing financial schedules, Schedule 12, Line 19, Column 4
3	2019 Earnings Sharing financing true-up	(0.015)	
4	Add: 2020 Forecasted Earnings Sharing financing	0.037	
5	**2019/2020 Financing Adjustments**	**0.022**	

14.4.5 Summary of 2019 Earnings Sharing

After calculating the 2019 actual earnings sharing and including the adjustments described above, FEI proposes to recover $1.653 million from customers ($1.206 million after tax) in 2020 revenue requirements. FEI will recover this amount through the amortization of both the actual 2020 opening after-tax balance and the 2020 financing in the Earnings Sharing deferral account.

14.5 SERVICE QUALITY INDICATORS

For the 2014-2019 PBR Plan, the BCUC approved a balanced set of SQIs covering safety, responsiveness to customer needs, and reliability. Nine of the SQIs have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation approved by the BCUC in Order G-14-15. Four of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

For each SQI, Table 14-8 below provides a comparison of FEI's 2019 SQI results under the 2014-2019 PBR Plan to the BCUC-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation that was approved by the BCUC. Actual 2019 results are also provided for the four informational SQIs.

Table 14-8: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2019 Results
Safety SQIs				
Emergency Response Time	Percent of calls responded to within one hour	>=97.7%	96.2%	97.9%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>=95%	92.8%	97.2%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=2.08	2.95	1.64
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	<=16	16	8
Responsiveness to the Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	81%
Billing Index	Measure of customer bills produced meeting performance criteria	<=5.0	<=5.0	0.44
Meter Reading Accuracy	Number of scheduled meters that were read	>=95%	92%	95%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	71%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>=95%	93.8%	96.0%

Performance Measure	Description	Benchmark	Threshold	2019 Results
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.7
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.4%
Reliability SQIs				
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	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	-	-	0.0060

For all the SQIs with BCUC-approved benchmarks, 2019 annual performance met or were better than the approved benchmarks.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

1 **Table A1-1: Table 18-10-0004-01 (formerly CANSIM 326-0020)**

Add/Remove data

Consumer Price Index, monthly, not seasonally adjusted [1 2 3]

Frequency: Monthly

Table: 18-10-0004-01 (formerly CANSIM 326-0020)

Help

Geography: Canada, Province or territory, Census subdivision, Census metropolitan area, Census metropolitan area part

Save my customizations

▸ Customize table (Add/Remove data)

Didn't find what you're looking for? View related tables, including other calculations and frequencies

Download options

Products and product groups [3 4]	Reference period	British Columbia (map)
		2002=100
	July 2017	125.6
	August 2017	125.9
	September 2017	125.7
	October 2017	125.6
	November 2017	125.9
	December 2017	125.2
	January 2018	126.1
	February 2018	127.0
	March 2018	127.4
	April 2018	127.7
	May 2018	128.4
	June 2018	128.6
	July 2018	129.7
	August 2018	129.6
	September 2018	128.9
	October 2018	129.4
	November 2018	128.9
	December 2018	129.0
All-items	January 2019	129.1
	February 2019	129.8

2

	March 2019	130.7
	April 2019	131.2
	May 2019	131.8
	June 2019	131.9
	July 2019	132.4
	August 2019	132.2
	September 2019	132.0
	October 2019	132.2
	November 2019	131.8
	December 2019	131.7
	January 2020	132.1
	February 2020	132.9
	March 2020	132.3
	April 2020	131.2
	May 2020	131.5
	June 2020	132.6

Table A1-2: Table 14-10-0223-01 (formerly CANSIM 281-0063)

Add/Remove data

Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted [1][2][3][4][5]

Frequency: Monthly

Table: 14-10-0223-01 (formerly CANSIM 281-0063)

Geography: Canada, Province or territory

Help

Save my customizations

▸ Customize table (Add/Remove data)

Download options

Geography	Estimate	Reference period	Industrial aggregate including unclassified businesses [6][7]	Industrial aggregate excluding unclassified businesses [6][7]
			Dollars	
British Columbia (map)	Average weekly earnings including overtime for all employees [6]	July 2017	..	939.88 A
		August 2017	..	939.79 A
		September 2017	..	951.51 A
		October 2017	..	950.29 A
		November 2017	..	952.12 A
		December 2017	..	958.25 A
		January 2018	..	957.22 A
		February 2018	..	962.48 A
		March 2018	..	963.99 A
		April 2018	..	953.93 A
		May 2018	..	956.99 A
		June 2018	..	967.63 A
		July 2018	..	974.29 A
		August 2018	..	979.82 A
		September 2018	..	975.65 A
		October 2018	..	978.07 A
		November 2018	..	979.83 A
		December 2018	..	976.63 A
		January 2019	..	973.10 A
		February 2019	..	974.09 A

		March 2019	..	986.67[A]
		April 2019	..	991.01[A]
		May 2019	..	1,001.50[A]
		June 2019	..	993.45[A]
		July 2019	..	996.11[A]
		August 2019	..	1,003.60[A]
		September 2019	..	1,008.09[B]
		October 2019	..	1,015.74[B]
		November 2019	..	1,012.40[B]
		December 2019	..	1,014.52[B]
		January 2020	..	1,025.61[B]
		February 2020	..	1,025.17[B]
		March 2020	..	1,029.38[B]
		April 2020	..	1,106.54[B]
		May 2020	..	1,123.79[B]

Symbol legend:

.. not available for a specific reference period

A data quality: excellent

B data quality: very good

Table A1-3: CBOC BC Housing Starts Embedded in Forecast as Filed

Date Published: 5th Dec 2019
Provincial Medium Term
Forecast: 20 Run: 20
Table: LTPF156 and LTPF157

BRITISH COLUMBIA	**2018**	**2019**	**2020**	**2021**
Forecasted Single-Family Housing Starts (Units)	11,163	9,480	9,063	7,957
Forecast Percent Change	-9.6%	-15.1%	-4.4%	-12.2%
Forecasted Multi-Family Housing Starts (Units)	29,694	36,246	28,789	26,933
Forecast Percent Change	-5.2%	22.1%	-20.6%	-6.4%
Forecast Housing Starts Total	40,857	45,726	37,851.8	34,890.3

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. 2010 – 2019 Actual data
    b. 2020 Projected data
    c. 2021 Forecast data
2. Percent Error
    a. 2010 - 2019 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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
RS 1	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	950,330	958,899
RS 2	85,193	85,704	81,123	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,558	90,430
RS 3	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973	7,221	7,469
RS 23	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871	906	941
Industrial	1,017	951	954	981	977	976	955	976	989	1,020	1,051	1,022
NGT	0	2	5	10	18	31	42	56	41	53	77	77
Total	946,574	953,943	942,872	953,295	964,971	979,277	991,591	1,006,043	1,027,092	1,038,354	1,049,143	1,058,838

FEI Customer Additions

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
RS 1	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	9,579	8,569
RS 2	128	511	577	1,329	1,173	1,450	998	899	1,271	442	872	872
RS 3	37	-16	-104	-86	35	132	-112	252	587	945	248	248
RS 23	58	27	88	9	-7	202	79	-91	-64	-777	35	35
Industrial	-96	-66	8	27	-4	-1	-21	21	13	31	31	-29
NGT	0	2	3	5	8	13	11	14	-15	12	24	0
Total	9,313	7,369	6,943	10,423	11,676	14,305	12,314	14,452	21,049	11,262	10,789	9,695

FEI Normalized Use Per Customer (Gjs)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
RS 1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	85.7	83.1
RS 2	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	324.9	321.8
RS 3	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	3,648	3,551
RS 23	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051	5,480	5,278

FEI Energy (Pjs)[(1)]

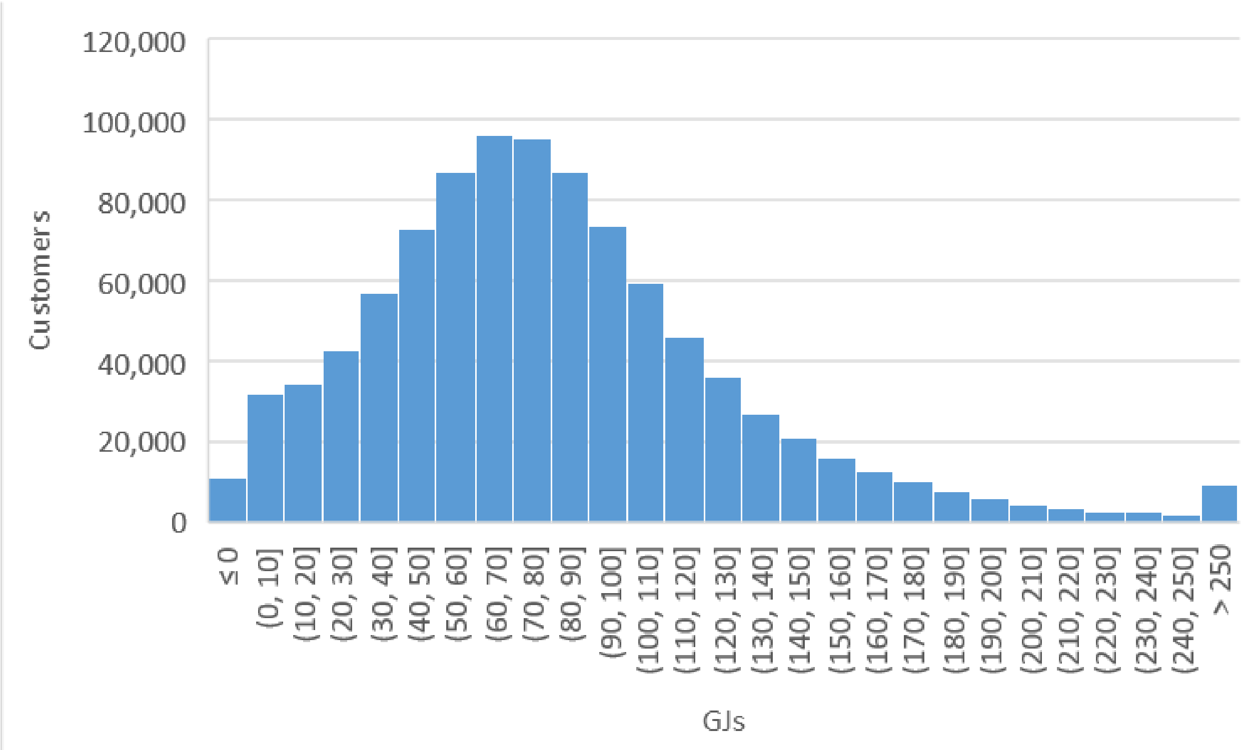
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
RS 1	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.1	79.3
RS 2	26.9	27.1	27.6	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.9	28.9
RS 3	19.0	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	25.2	26.2
RS 23	6.6	7.4	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.8	4.9
Industrial	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5	91.9	87.8
Sub-Total	201.9	206.6	209.7	206.3	205.7	209.5	219.3	223.3	225.8	226.4	232.0	227.1
NGT	0.0	0.1	0.2	0.3	0.8	1.1	1.3	1.8	1.6	2.6	3.4	6.4
Total	201.9	206.7	209.9	206.6	206.5	210.6	220.6	225.0	227.3	229.0	235.4	233.6

Table A2-2: FEI 2021F Industrial Forecast Demand by Region[2]

Industrial	2021 Forecast Demand By Region (PJs)
Mainland	65.2
Vancouver Island	22.6
Whistler	0.1
Total	**87.8**

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 2019



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 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. In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules for periods prior to 2015. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates Methodology Application, Section 4.2, as approved by BCUC Order G-131-14.

3.1 *AMALGAMATED NET CUSTOMERS*

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	849,539	857,592	870,980	880,331	866,852	883,371	892,830	909,727	916,365	934,804
Actual	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751
Error = (ACT-FCST)	3,953	2,811	(16,930)	(17,142)	6,809	2,798	4,698	1,158	13,777	5,947
Percent Error = (Error/ACT)	0.5%	0.3%	-2.0%	-2.0%	0.8%	0.3%	0.5%	0.1%	1.5%	0.6%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	86,383	87,262	85,482	85,627	81,923	84,651	85,667	87,712	88,494	89,203
Actual	85,193	85,704	81,123	82,452	83,625	85,076	86,074	86,973	88,244	88,686
Error = (ACT-FCST)	(1,190)	(1,558)	(4,359)	(3,175)	1,702	425	407	(739)	(250)	(517)
Percent Error = (Error/ACT)	-1.4%	-1.8%	-5.4%	-3.9%	2.0%	0.5%	0.5%	-0.8%	-0.3%	-0.6%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	5,671	5,785	5,553	5,597	5,147	5,117	5,035	5,354	5,223	5,623
Actual	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973
Error = (ACT-FCST)	(205)	(334)	(333)	(463)	22	184	154	87	805	1,350
Percent Error = (Error/ACT)	-3.8%	-6.1%	-6.4%	-9.0%	0.4%	3.5%	3.0%	1.6%	13.4%	19.4%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	1,319	1,328	1,526	1,586	1,634	1,552	1,670	1,760	1,934	1,744
Actual	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871
Error = (ACT-FCST)	87	105	(6)	(57)	(112)	172	133	(48)	(286)	(873)
Percent Error = (Error/ACT)	6.2%	7.3%	-0.4%	-3.7%	-7.4%	10.0%	7.4%	-2.8%	-17.4%	-100.2%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.2 AMALGAMATED NET CUSTOMER ADDITIONS

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	7,012	7,724	8,984	9,352	6,647	9,710	9,461	11,522	9,141	10,724
Actual	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609
Error = (ACT-FCST)	2,174	(813)	(2,613)	(213)	3,825	2,798	1,898	1,835	10,116	(115)
Percent Error = (Error/ACT)	23.7%	-11.8%	-41.0%	-2.3%	36.5%	22.4%	16.7%	13.7%	52.5%	-1.1%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	830	877	145	145	411	1,026	1,026	1,318	1,210	1,115
Actual	128	511	577	1,329	1,173	1,450	998	899	1,271	442
Error = (ACT-FCST)	(702)	(366)	432	1,184	762	424	(28)	(419)	61	(673)
Percent Error = (Error/ACT)	-548.4%	-71.6%	74.9%	89.1%	65.0%	29.2%	-2.8%	-46.6%	4.8%	-152.3%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	105	114	44	44	4	(52)	(51)	26	19	91
Actual	37	(16)	(104)	(86)	35	132	(112)	252	587	945
Error = (ACT-FCST)	(68)	(130)	(148)	(130)	31	184	(61)	226	568	854
Percent Error = (Error/ACT)	-183.8%	812.5%	142.3%	151.2%	88.6%	139.4%	54.5%	89.7%	96.8%	90.4%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	9	9	60	60	57	30	30	18	66	16
Actual	58	27	88	9	(7)	202	79	(91)	(64)	(777)
Error = (ACT-FCST)	49	18	28	(51)	(64)	172	49	(109)	(130)	(793)
Percent Error = (Error/ACT)	84.5%	66.7%	31.8%	-566.7%	914.3%	85.1%	62.0%	119.8%	203.1%	102.1%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	87.9	86.5	86.3	85.2	86.0	83.1	81.6	82.2	89.1	87.0
Actual	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4
Error = (ACT-FCST)	0.5	(0.2)	1.3	(0.5)	(1.8)	1.3	5.9	3.7	(4.0)	(4.6)
Percent Error = (Error/ACT)	0.6%	-0.2%	1.5%	-0.6%	-2.1%	1.5%	6.7%	4.3%	-4.7%	-5.6%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	320.5	320.2	315.0	314.5	340.0	333.7	329.5	328.4	345.2	341.3
Actual	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1
Error = (ACT-FCST)	(4.3)	(2.5)	26.2	17.1	(9.4)	(1.1)	9.6	8.3	(12.7)	(23.2)
Percent Error = (Error/ACT)	-1.4%	-0.8%	7.7%	5.2%	-2.8%	-0.3%	2.8%	2.5%	-3.8%	-7.3%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	3,496	3,487	3,450	3,435	3,872	3,754	3,593	3,488	3,842	3,831
Actual	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517
Error = (ACT-FCST)	(11)	101	234	175	(299)	(167)	128	205	(292)	(314)
Percent Error = (Error/ACT)	-0.3%	2.8%	6.4%	4.8%	-8.4%	-4.7%	3.4%	5.5%	-8.2%	-8.9%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	4,680	4,680	4,901	4,927	5,546	5,309	5,382	5,227	5,399	5,492
Actual	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051
Error = (ACT-FCST)	170	458	337	222	(286)	(135)	(103)	133	(54)	(440)
Percent Error = (Error/ACT)	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.6%	-2.0%	2.5%	-1.0%	-8.7%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.4 AMALGAMATED DEMAND

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	74.3	73.8	74.7	74.6	74.2	73.1	72.5	74.3	81.2	80.8
Actual	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0
Error = (ACT-FCST)	0.7	0.1	(0.2)	(1.9)	(1.0)	1.0	5.4	3.3	(2.9)	(3.7)
Percent Error = (Error/ACT)	0.9%	0.1%	-0.3%	-2.6%	-1.4%	1.3%	6.9%	4.2%	-3.7%	-4.9%

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	27.5	27.7	26.9	26.9	27.7	28.1	28.0	28.5	30.3	30.2
Actual	26.9	27.1	27.6	27.0	27.5	28.0	29.0	29.1	29.1	28.1
Error = (ACT-FCST)	(0.6)	(0.6)	0.7	0.1	(0.2)	(0.1)	1.0	0.6	(1.2)	(2.1)
Percent Error = (Error/ACT)	-2.2%	-2.2%	2.5%	0.4%	-0.7%	-0.4%	3.4%	2.0%	-4.3%	-7.4%

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	19.6	19.9	19.1	19.1	19.9	19.2	18.1	18.7	20.1	21.5
Actual	19.0	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5
Error = (ACT-FCST)	(0.6)	(0.4)	0.2	(0.4)	(1.4)	(0.0)	1.3	1.0	0.9	1.0
Percent Error = (Error/ACT)	-3.2%	-2.1%	1.0%	-2.1%	-7.6%	-0.2%	6.7%	5.2%	4.1%	4.3%

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	6.1	6.2	7.2	7.5	8.7	8.3	9.0	9.2	10.3	9.6
Actual	6.6	7.4	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3
Error = (ACT-FCST)	0.5	1.2	0.6	0.4	(0.7)	0.3	0.3	0.4	(1.3)	(2.3)
Percent Error = (Error/ACT)	7.6%	16.2%	7.7%	5.1%	-8.7%	3.5%	3.2%	3.9%	-13.9%	-31.3%

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Commercial										
Forecast	53.2	53.8	53.2	53.5	56.3	55.6	55.1	56.4	60.7	61.3
Actual	52.5	54.0	54.7	53.6	54.0	55.8	57.7	58.3	59.0	57.9
Error = (ACT-FCST)	(0.7)	0.2	1.5	0.1	(2.3)	0.2	2.6	2.0	(1.6)	(3.4)
Percent Error = (Error/ACT)	-1.3%	0.4%	2.7%	0.2%	-4.3%	0.3%	4.5%	3.4%	-2.8%	-5.9%

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Industrial*										
Forecast	73.2	71.3	72.1	72.1	86.2	76.4	78.1	82.1	84.3	90.6
Actual	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5
Error = (ACT-FCST)	1.2	7.5	8.5	8.0	(7.6)	3.2	5.6	5.3	4.2	0.9
Percent Error = (Error/ACT)	1.6%	9.5%	10.5%	10.0%	-9.7%	4.0%	6.7%	6.0%	4.7%	1.0%

Demand,PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FEI										
Forecast	200.7	198.9	200.0	200.2	216.7	205.2	205.7	212.8	226.2	232.6
Actual	201.9	206.7	209.8	206.4	205.8	209.5	219.3	223.3	225.8	226.4
Error = (ACT-FCST)	1.2	7.8	9.8	6.2	(10.9)	4.3	13.6	10.5	(0.4)	(6.2)
Percent Error = (Error/ACT)	0.6%	3.8%	4.7%	3.0%	-5.3%	2.1%	6.2%	4.7%	-0.2%	-2.7%

*Excld NGT and Burrard
2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.5 MAINLAND NET CUSTOMERS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	757,161	762,460	773,231	780,005	768,622	780,972	787,836	799,732	803,319	813,959
Actual	760,559	765,553	759,712	766,668	774,083	782,914	790,562	798,917	811,696	817,817
Error = (ACT-FCST)	3,398	3,093	(13,519)	(13,337)	5,461	1,942	2,726	(815)	8,377	3,858
Percent Error = (Error/ACT)	0.4%	0.4%	-1.8%	-1.7%	0.7%	0.2%	0.3%	-0.1%	1.0%	0.5%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	77,204	77,954	76,126	76,175	72,922	75,315	76,166	77,597	78,228	78,767
Actual	76,028	76,437	72,235	73,480	74,464	75,451	76,326	77,047	78,044	78,351
Error = (ACT-FCST)	(1,176)	(1,517)	(3,891)	(2,695)	1,542	136	160	(550)	(184)	(416)
Percent Error = (Error/ACT)	-1.5%	-2.0%	-5.4%	-3.7%	2.1%	0.2%	0.2%	-0.7%	-0.2%	-0.5%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	5,083	5,191	4,962	5,002	4,577	4,560	4,497	4,667	4,608	5,029
Actual	4,882	4,863	4,675	4,598	4,625	4,671	4,605	4,867	5,478	6,291
Error = (ACT-FCST)	(201)	(328)	(287)	(404)	48	111	108	200	870	1,262
Percent Error = (Error/ACT)	-4.1%	-6.7%	-6.1%	-8.8%	1.0%	2.4%	2.3%	4.1%	15.9%	20.1%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	1,319	1,328	1,526	1,586	1,634	1,552	1,582	1,609	1,669	1,562
Actual	1,406	1,433	1,520	1,529	1,522	1,573	1,614	1,546	1,458	800
Error = (ACT-FCST)	87	105	(6)	(57)	(112)	21	32	(63)	(211)	(762)
Percent Error = (Error/ACT)	6.2%	7.3%	-0.4%	-3.7%	-7.4%	1.3%	2.0%	-4.1%	-14.5%	-95.3%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.6 MAINLAND NET CUSTOMER ADDITIONS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	4,777	4,983	6,507	6,774	4,594	6,889	6,863	8,250	6,203	6,756
Actual	6,824	4,994	4,475	6,956	7,415	8,831	7,648	8,355	12,779	6,121
Error = (ACT-FCST)	2,047	11	(2,032)	182	2,821	1,942	785	105	6,576	(635)
Percent Error = (Error/ACT)	30.0%	0.2%	-45.4%	2.6%	38.0%	22.0%	10.3%	1.3%	51.5%	-10.4%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	713	750	49	49	331	851	851	1,072	951	860
Actual	42	409	325	1,245	984	987	875	721	997	307
Error = (ACT-FCST)	(671)	(341)	276	1,196	653	136	24	(351)	46	(553)
Percent Error = (Error/ACT)	-1597.6%	-83.4%	84.9%	96.1%	66.4%	13.7%	2.7%	-48.7%	4.6%	-180.1%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	101	108	40	40	-	(65)	(64)	(1)	2	81
Actual	41	(19)	(144)	(77)	27	46	(66)	262	611	813
Error = (ACT-FCST)	(60)	(127)	(184)	(117)	27	111	(2)	263	609	732
Percent Error = (Error/ACT)	-146.3%	668.4%	127.8%	151.9%	100.0%	241.3%	3.0%	100.4%	99.7%	90.0%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	9	9	60	60	57	30	30	18	28	8
Actual	58	27	88	9	(7)	51	41	(68)	(88)	(658)
Error = (ACT-FCST)	49	18	28	(51)	(64)	21	11	(86)	(116)	(666)
Percent Error = (Error/ACT)	84.5%	66.7%	31.8%	-566.7%	914.3%	41.2%	26.8%	126.5%	131.8%	101.2%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.7 MAINLAND NORMALIZED USE PER CUSTOMER

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	91.7	90.3	90.8	89.9	90.7	88.1	86.3	86.2	93.5	91.5
Actual	92.6	90.4	92.2	89.3	88.8	88.7	92.0	90.4	89.7	87.1
Error = (ACT-FCST)	0.9	0.1	1.4	(0.6)	(1.9)	0.6	5.7	4.2	(3.8)	(4.5)
Percent Error = (Error/ACT)	1.0%	0.1%	1.5%	-0.7%	-2.1%	0.7%	6.2%	4.6%	-4.2%	-5.1%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	317.8	317.8	308.0	306.4	333.6	328.9	328.5	327.3	344.5	338.6
Actual	311.3	313.7	337.6	329.6	330.4	329.6	338.0	335.2	329.4	315.6
Error = (ACT-FCST)	(6.5)	(4.1)	29.6	23.2	(3.2)	0.7	9.5	7.9	(15.2)	(23.0)
Percent Error = (Error/ACT)	-2.1%	-1.3%	8.8%	7.0%	-1.0%	0.2%	2.8%	2.4%	-4.6%	-7.3%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	3,346	3,347	3,334	3,316	3,769	3,599	3,537	3,517	3,770	3,746
Actual	3,370	3,484	3,566	3,517	3,529	3,524	3,658	3,625	3,477	3,468
Error = (ACT-FCST)	24	137	232	201	(240)	(75)	121	108	(293)	(278)
Percent Error = (Error/ACT)	0.7%	3.9%	6.5%	5.7%	-6.8%	-2.1%	3.3%	3.0%	-8.4%	-8.0%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	4,680	4,680	4,901	4,927	5,546	5,309	5,348	5,197	5,416	5,521
Actual	4,850	5,138	5,238	5,149	5,260	5,157	5,304	5,388	5,357	5,127
Error = (ACT-FCST)	170	458	337	222	(286)	(152)	(44)	191	(59)	(394)
Percent Error = (Error/ACT)	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.9%	-0.8%	3.5%	-1.1%	-7.7%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.8 MAINLAND NORMALIZED DEMAND

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	69.2	68.6	69.9	69.8	69.5	68.5	67.7	68.6	74.8	74.2
Actual	70.0	68.9	69.8	68.1	68.5	68.9	72.3	71.8	72.2	70.9
Error = (ACT-FCST)	0.9	0.4	(0.1)	(1.7)	(1.0)	0.4	4.6	3.2	(2.6)	(3.2)
Percent Error = (Error/ACT)	1.2%	0.5%	-0.2%	-2.5%	-1.5%	0.5%	6.4%	4.5%	-3.6%	-4.6%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	24.4	24.6	23.4	23.3	24.2	24.7	24.9	25.2	26.7	26.5
Actual	23.6	23.9	24.3	23.9	24.5	24.6	25.6	25.7	25.5	24.7
Error = (ACT-FCST)	(0.8)	(0.7)	0.9	0.6	0.2	(0.0)	0.7	0.5	(1.3)	(1.8)
Percent Error = (Error/ACT)	-3.2%	-3.0%	3.6%	2.5%	0.9%	-0.2%	2.7%	2.0%	-5.0%	-7.3%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	16.8	17.2	16.5	16.5	17.3	16.4	16.0	16.4	17.4	18.8
Actual	16.4	16.9	16.7	16.3	16.3	16.5	16.8	17.3	18.5	20.1
Error = (ACT-FCST)	(0.4)	(0.3)	0.2	(0.2)	(1.0)	0.0	0.8	0.9	1.2	1.3
Percent Error = (Error/ACT)	-2.4%	-1.8%	1.2%	-1.2%	-6.1%	0.3%	5.0%	5.4%	6.3%	6.4%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast	6.1	6.2	7.2	7.5	8.7	8.3	8.4	8.3	9.0	8.6
Actual	6.6	7.4	7.8	7.9	8.0	8.0	8.4	8.6	8.1	6.6
Error = (ACT-FCST)	0.5	1.2	0.6	0.4	(0.7)	(0.3)	-	0.3	(0.8)	(2.0)
Percent Error = (Error/ACT)	7.6%	16.2%	7.7%	5.1%	-8.7%	-3.3%	0.0%	3.1%	-10.4%	-30.8%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Commercial										
Forecast	47.3	48.0	47.1	47.3	50.2	49.3	49.3	49.9	53.1	53.9
Actual	46.6	48.2	48.8	48.1	48.8	49.1	50.8	51.6	52.2	51.3
Error = (ACT-FCST)	(0.7)	0.2	1.7	0.8	(1.5)	(0.3)	1.5	1.7	(0.9)	(2.5)
Percent Error = (Error/ACT)	-1.4%	0.4%	3.4%	1.6%	-3.0%	-0.5%	3.0%	3.3%	-1.8%	-5.0%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.9 VANCOUVER ISLAND AND WHISTLER AMALGAMATED DATA

In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules for periods prior to 2015. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates Methodology Application, Section 4.2 as approved by BCUC Order G-131-14. Tables in Sections 3.10 through 3.17 use this mapped data for historical calculations.

1 ## 3.10 *VANCOUVER ISLAND NET CUSTOMERS*

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	90,106	92,811	95,460	98,023	95,858	99,921	102,458	107,314	110,270	117,957
Actual	90,671	92,554	92,067	94,173	97,162	100,747	104,358	109,259	115,618	119,998
Error = (ACT-FCST)	565	(257)	(3,393)	(3,850)	1,304	826	1,900	1,945	5,348	2,041
Percent Error = (Error/ACT)	0.6%	-0.3%	-3.7%	-4.1%	1.3%	0.8%	1.8%	1.8%	4.6%	1.7%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	8,917	9,042	9,081	9,172	8,710	9,047	9,209	9,808	9,971	10,131
Actual	8,900	8,981	8,613	8,691	8,875	9,330	9,459	9,629	9,891	10,028
Error = (ACT-FCST)	(17)	(61)	(468)	(481)	165	283	250	(179)	(80)	(103)
Percent Error = (Error/ACT)	-0.19%	-0.68%	-5.43%	-5.53%	1.86%	3.03%	2.64%	-1.86%	-0.81%	-1.03%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	527	532	532	536	509	497	479	647	567	539
Actual	525	527	484	476	484	582	531	517	492	613
Error = (ACT-FCST)	(2)	(5)	(48)	(60)	(25)	85	52	(130)	(75)	74
Percent Error = (Error/ACT)	-0.38%	-0.95%	-9.92%	-12.61%	-5.17%	14.60%	9.79%	-25.15%	-15.24%	12.06%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							83	141	243	164
Actual						141	175	152	179	67
Error = (ACT-FCST)						141	92	11	(64)	(97)
Percent Error = (Error/ACT)							52.57%	7.24%	-35.75%	-144.78%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.11 VANCOUVER ISLAND NET CUSTOMER ADDITIONS

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	2,200	2,705	2,463	2,564	2,001	2,759	2,537	3,188	2,857	3,888
Actual	2,350	1,883	1,845	2,106	2,989	3,583	3,611	4,901	6,359	4,380
Error = (ACT-FCST)	150	(822)	(618)	(458)	988	824	1074	1713	3502	492
Percent Error = (Error/ACT)	6.4%	-43.7%	-33.5%	-21.7%	33.1%	23.0%	29.8%	35.0%	55.1%	11.2%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	116	125	91	91	71	171	171	239	256	251
Actual	85	81	251	78	184	453	129	170	262	137
Error = (ACT-FCST)	(31)	(44)	160	(13)	113	282	(42)	(69)	6	(114)
Percent Error = (Error/ACT)	-36.4%	-54.1%	63.8%	-16.4%	61.1%	62.2%	-32.6%	-40.6%	2.3%	-83.2%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	4	5	4	4	4	13	13	32	19	11
Actual	(2)	2	39	(8)	8	98	(51)	(14)	(25)	121
Error = (ACT-FCST)	(6)	(3)	35	(12)	4	85	(64)	(46)	(44)	110
Percent Error = (Error/ACT)	300.0%	-150.0%	89.7%	150.0%	50.0%	86.6%	125.5%	328.6%	176.0%	90.9%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							-	-	34	6
Actual						141	34	(23)	27	(112)
Error = (ACT-FCST)						141	34	(23)	(7)	(118)
Percent Error = (Error/ACT)							100.0%	100.0%	-25.9%	105.4%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.12 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	55.0	54.9	48.6	46.9	45.0	44.0	45.1	51.3	56.3	54.7
Actual	52.5	51.8	49.5	47.3	47.1	50.5	52.6	51.5	51.6	49.7
Error = (ACT-FCST)	(2.5)	(3.1)	0.9	0.4	2.1	6.5	7.5	0.3	(4.7)	(5.0)
Percent Error = (Error/ACT)	-4.8%	-6.0%	1.8%	0.8%	4.5%	12.9%	14.3%	0.5%	-9.1%	-10.1%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	340.0	337.0	365.0	372.0	390.0	372.0	334.0	322.8	342.5	357.0
Actual	351.0	345.0	369.0	344.0	328.0	346.0	343.0	344.8	351.2	332.7
Error = (ACT-FCST)	11.0	8.0	4.0	(28.0)	(62.0)	(26.0)	9.0	22.0	8.7	(24.3)
Percent Error = (Error/ACT)	3.1%	2.3%	1.1%	-8.1%	-18.9%	-7.5%	2.6%	6.4%	2.5%	-7.3%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	6,295	6,349	6,351	6,398	5,896	5,187	4,031	3,069	4,171	4,411
Actual	4,435	4,460	4,820	4,431	3,901	3,894	4,060	4,181	4,074	3,827
Error = (ACT-FCST)	(1,860)	(1,889)	(1,531)	(1,967)	(1,995)	(1,293)	29	1,112	(97)	(584)
Percent Error = (Error/ACT)	-41.9%	-42.4%	-31.8%	-44.4%	-51.1%	-33.2%	0.7%	26.6%	-2.4%	-15.3%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							5,996	5,636	5,344	5,282
Actual						5,636	5,052	5,158	5,260	4,369
Error = (ACT-FCST)							(944)	(478)	(83)	(913)
Percent Error = (Error/ACT)							-18.7%	-9.3%	-1.6%	-20.9%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.13 VANCOUVER ISLAND NORMALIZED DEMAND

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	4.9	5.0	4.6	4.5	4.3	4.3	4.6	5.4	6.1	6.3
Actual	4.7	4.7	4.5	4.4	4.5	5.0	5.4	5.5	5.8	5.9
Error = (ACT-FCST)	(0.2)	(0.3)	(0.1)	(0.1)	0.2	0.6	0.8	0.1	(0.3)	(0.5)
Percent Error = (Error/ACT)	-4.3%	-6.4%	-2.2%	-2.3%	4.4%	12.9%	15.6%	1.5%	-5.6%	-8.3%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	3.0	3.0	3.3	3.4	3.3	3.3	3.0	3.1	3.4	3.6
Actual	3.1	3.1	3.1	3.0	2.9	3.2	3.2	3.3	3.4	3.3
Error = (ACT-FCST)	0.1	0.1	(0.2)	(0.4)	(0.5)	(0.2)	0.2	0.2	0.0	(0.3)
Percent Error = (Error/ACT)	3.2%	1.6%	-5.1%	-14.9%	-16.0%	-4.7%	6.3%	5.4%	1.4%	-8.0%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	2.5	2.5	2.4	2.4	2.4	2.5	1.9	2.0	2.4	2.4
Actual	2.3	2.3	2.3	2.1	1.9	2.4	2.2	2.1	2.1	2.0
Error = (ACT-FCST)	(0.2)	(0.2)	(0.1)	(0.3)	(0.5)	(0.1)	0.3	0.1	(0.3)	(0.3)
Percent Error = (Error/ACT)	-6.8%	-8.1%	-2.6%	-13.7%	-28.3%	-5.0%	13.6%	6.5%	-14.6%	-16.8%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							0.5	0.8	1.2	0.8
Actual						0.5	0.8	0.9	0.8	0.6
Error = (ACT-FCST)						(0.5)	(0.3)	(0.1)	0.4	0.2
Percent Error = (Error/ACT)							-37.50%	-9.16%	44.93%	32.22%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Commercial										
Forecast	5.5	5.6	5.7	5.8	5.7	5.9	5.4	5.9	7.0	6.8
Actual	5.5	5.4	5.5	5.1	4.8	6.2	6.2	6.3	6.3	6.0
Error = (ACT-FCST)	(0.1)	(0.1)	(0.2)	(0.7)	(1.0)	0.3	0.8	0.4	(0.6)	(0.8)
Percent Error = (Error/ACT)	-1.1%	-2.6%	-4.0%	-14.4%	-20.8%	4.4%	12.9%	6.3%	-10.0%	-13.6%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.14 WHISTLER NET CUSTOMERS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	2,272	2,321	2,289	2,303	2,372	2,478	2,536	2,681	2,775	2,889
Actual	2,262	2,296	2,271	2,348	2,416	2,508	2,608	2,709	2,828	2,936
Error = (ACT-FCST)	(10)	(25)	(18)	45	44	30	72	28	53	47
Percent Error = (Error/ACT)	-0.4%	-1.1%	-0.8%	1.9%	1.8%	1.2%	2.8%	1.0%	1.9%	1.6%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	263	267	275	280	291	289	292	309	294	305
Actual	265	286	274	281	285	295	289	297	309	307
Error = (ACT-FCST)	2	19	(1)	1	(6)	6	(3)	(12)	15	2
Percent Error = (Error/ACT)	0.8%	6.6%	-0.4%	0.4%	-2.1%	2.0%	-1.0%	-4.0%	4.7%	0.7%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	61	62	59	59	61	60	59	39	48	55
Actual	59	61	61	60	60	48	53	57	58	69
Error = (ACT-FCST)	(2)	(1)	2	1	(1)	(12)	(6)	18	10	14
Percent Error = (Error/ACT)	-3.4%	-1.6%	3.3%	1.7%	-1.7%	-25.0%	-11.3%	31.6%	16.9%	20.2%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							5	10	22	18
Actual						10	14	14	11	4
Error = (ACT-FCST)						10	9	4	(11)	(14)
Percent Error = (Error/ACT)							64.3%	28.6%	-100.0%	-350.0%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	35	36	14	14	52	62	61	84	81	81
Actual	12	34	51	77	68	92	100	101	119	108
Error = (ACT-FCST)	(23)	(2)	37	63	16	30	39	17	38	27
Percent Error = (Error/ACT)	-191.7%	-5.9%	72.5%	81.8%	23.5%	32.6%	39.0%	16.8%	31.8%	25.4%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	1	2	5	5	9	4	4	7	3	4
Actual	2	21	-	7	5	10	(6)	8	12	(2)
Error = (ACT-FCST)	1	19	(5)	2	(4)	6	(10)	1	9	(6)
Percent Error = (Error/ACT)	50.0%	90.5%		28.6%	-80.0%	60.0%	166.7%	11.9%	77.4%	300.0%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast		1				-	-	(5)	(2)	(1)
Actual		2	(0)	(1)	(0)	(12)	5	4	1	11
Error = (ACT-FCST)		1				(12)	5	9	3	12
Percent Error = (Error/ACT)		41.1%					100.0%	225.0%	339.0%	109.1%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							-	-	4	2
Actual						10	4	-	(3)	(7)
Error = (ACT-FCST)						10	4	0	(7)	(9)
Percent Error = (Error/ACT)							100.0%			

2019* Rate Switching (Large Commercial Rs3 and Rs23)

3.16 WHISTLER NORMALIZED USE PER CUSTOMER

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	92.1	82.3	104.0	106.3	90.6	79.7	85.1	97.9	102.1	99.5
Actual	99.5	94.7	89.4	87.3	87.6	91.3	97.7	93.5	96.3	94.2
Error = (ACT-FCST)	7.4	12.4	(14.6)	(19.0)	(3.0)	11.6	12.6	(4.4)	(5.8)	(5.3)
Percent Error = (Error/ACT)	7.4%	13.1%	-16.3%	-21.8%	-3.4%	12.7%	12.9%	-4.7%	-6.1%	-5.6%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	464.0	430.0	610.0	637.0	464.0	408.0	465.0	792.9	592.7	515.5
Actual	563.0	506.0	429.0	465.0	471.0	660.0	520.2	479.4	511.8	465.8
Error = (ACT-FCST)	99.0	76.0	(181.0)	(172.0)	7.0	252.0	55.2	(313.5)	(80.9)	(49.7)
Percent Error = (Error/ACT)	17.6%	15.0%	-42.2%	-37.0%	1.5%	38.2%	10.6%	-65.4%	-15.8%	-10.7%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	4,894	4,114	3,876	3,630	3,595	3,822	4,326	6,707	6,824	5,886
Actual	4,512	4,271	3,822	4,213	4,285	5,618	5,638	5,108	5,747	5,392
Error = (ACT-FCST)	(382)	157	(54)	583	690	1,796	1,312	(1,599)	(1,077)	(495)
Percent Error = (Error/ACT)	-8.5%	3.7%	-1.4%	13.8%	16.1%	32.0%	23.3%	-31.3%	-18.7%	-9.2%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							5,888	4,328	4,703	4,654
Actual						4,328	5,078	4,557	4,860	5,045
Error = (ACT-FCST)							(810)	229	157	391
Percent Error = (Error/ACT)							-16.0%	5.0%	3.2%	7.7%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

1 ## 3.17 WHISTLER NORMALIZED DEMAND

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 1										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Actual	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	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)	7.5%	12.0%	-14.2%	-21.5%	-1.4%	0.0%	14.6%	-4.1%	-5.3%	-4.6%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rate Schedule 2										
Forecast	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.2
Actual	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1
Error = (ACT-FCST)	0.0	0.0	(0.0)	(0.0)	0.0	0.1	0.0	(0.1)	(0.0)	(0.0)
Percent Error = (Error/ACT)	20.0%	21.4%	-33.3%	-30.8%	0.0%	36.8%	10.0%	-75.0%	-12.1%	-9.6%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 3										
Forecast	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Actual	0.3	0.3	0.2	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	0.1	0.0	0.0	(0.0)	0.0
Percent Error = (Error/ACT)	-11.1%	3.8%	0.0%	15.4%	15.4%	17.9%	13.3%	3.5%	-3.8%	5.5%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Rate Schedule 23										
Forecast							0.03	0.04	0.09	0.08
Actual						0.03	0.06	0.06	0.06	0.05
Error = (ACT-FCST)							0.03	0.02	-0.03	-0.03
Percent Error = (Error/ACT)							50.9%	32.2%	-44.7%	-73.7%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Commercial										
Forecast	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6
Actual	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Error = (ACT-FCST)	0.0	0.0	(0.0)	0.0	0.0	0.2	0.1	(0.1)	(0.1)	(0.0)
Percent Error = (Error/ACT)	0.0%	10.0%	-11.4%	0.0%	10.3%	30.0%	16.8%	-15.0%	-11.1%	-5.4%

2 2019* Rate Switching (Large Commercial Rs3 and Rs23)

Appendix A2-1

HISTORICAL ACTUAL, FORECAST AND VARIANCE TABLES

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix A3

Demand Forecast Methods

Table of Contents

List of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides a detailed description of its demand forecast method.

The following table shows the high level method used for each component of FEI's demand forecast.

Table A3-1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg. historical additions	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Industrial				Annual survey of industrial customers

FEI's demand forecast methods are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

In the following sections, FEI provides background information, including a description of FEI's regions and rate classes, the time periods used in the forecast, and the weather normalization process, and then describes each of FEI's forecast methods used to derive the 2021 demand forecast, in the following order:

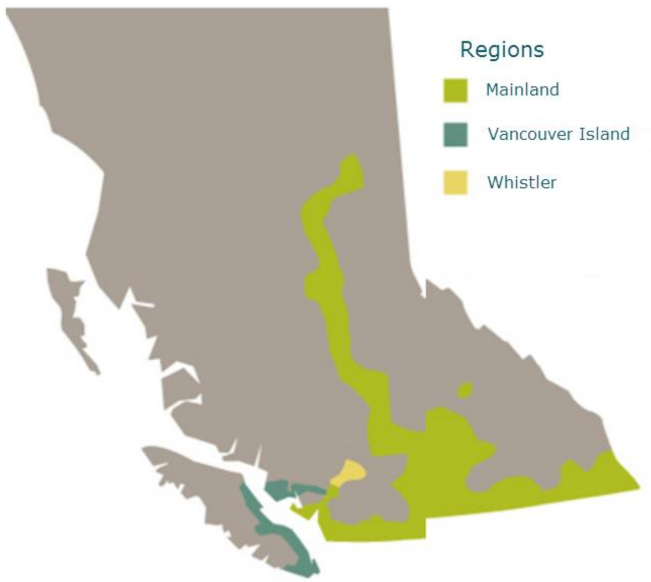
- Residential Customer Additions;
- Commercial Customer Additions;
- Residential and Commercial Use Rates;
- Residential and Commercial Demand Forecast; and
- Industrial Demand Forecast.

2. BACKGROUND INFORMATION

2.1 FEI REGIONS

FEI is divided into three regions as shown in Figure A3-1.

Figure A3-1: FEI Regions



The Mainland region is further divided into the following sub-regions:

- Lower Mainland
- Inland
- Columbia
- Revelstoke

Forecasting is performed at the sub-regional level for each rate schedule in the Mainland region and summed up to derive the Mainland region forecast, which is then added to the forecast for the Vancouver Island and Whistler regions to derive the total forecast for each rate schedule within FEI.

2.2 ACTUAL, PROJECTED AND FORECAST YEARS

FEI's demand forecasts contain data from three time frames:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.
- **Forecast Year(s)**: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or two or more years depending on the filing.
- **Projected Year:** Normally the most recent complete year of actual data is used to prepare the forecast, and this was the case for 2020. However as a result of the extraordinary circumstances related to the pandemic FEI has replaced the January to June 2020 forecast values with actuals. The actual values simply replaced the forecast values and then the forecast software (FIS) rolled up the modified monthly values into the annual UPCs published in the forecast. The forecast values for 2021 were not affected or altered in any way.

2.3 *RATE CLASSES*

The following residential, commercial and industrial rate classes are included in the annual demand forecast:

Table A3-2: Rate Classes

Residential	
Rate Schedule 1 - Residential	This rate schedule is applicable to firm gas supplied at one premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, row houses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
Commercial	
Rate Schedule 2 - Small Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of less than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 3 - Large Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 23 - Commercial Transportation	This rate schedule is applicable to shippers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

Industrial	
Rate Schedule 4 – Seasonal	This rate schedule applies to the sale of gas to one customer who, pursuant to this Rate Schedule, consumes gas during the off-peak period.
Rate Schedule 5 - General Firm	This rate schedule applies to the sale of firm gas through one meter station to a customer. Firm gas service under this Rate Schedule means the gas FEI is obligated to sell to a customer on a firm basis subject to interruption or curtailment.
Rate Schedule 7 - General Interruptible Sales	This rate schedule applies to the provision of a bundled interruptible transportation service and the sale of firm gas through one meter station to a customer.
Rate Schedule 22/22A/22B - Large Volume Transportation	This rate schedule applies to the provision of firm and/or interruptible transportation service (subject to a minimum of 12,000 gigajoules per month) through the FEI system and through one meter station to one shipper except as previously agreed upon.
Rate Schedule 25 - General Firm Transportation	This rate schedule applies to the provision of firm transportation service through the FEI system and through one meter station to one shipper.
Rate Schedule 27 - General Interruptible Transportation	This rate schedule applies to the provision of interruptible transportation service through the FEI system and through one meter station to one shipper.

2.4 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (Rate Schedules (RS) 1, RS 2, RS 3 and RS 23) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules as described in this section. Separate normalization factors are developed for each region, rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each region and rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load. As the relationship between weather and the usage is not linear, FEI considers three non-linear models that are often used when modeling weather impact. One is based on the Gompertz distribution (the “Gompertz” model). The other two methods are variants based on the logit formulation with one (Logit-4) allowing for an additional parameter for optimal fitting. The models are:

- Gompertz

$$Estimated\ Monthly\ UPC = A \times e^{\left(-e^{-B \times (Avg.Monthly\ Temp. - C)}\right)}$$

- Logit-3

$$Estimated\ Monthly\ UPC = \frac{A}{1 + B \times e^{(-C \times Temp)}}$$

- Logit-4

$$Estimated\ Monthly\ UPC = \frac{(D + (A - D))}{1 + B \times e^{(-C \times Temp)}}$$

The A/B/C/D parameters are estimated through a least squares method to minimize the sum of squared error (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The three non-linear models were tested to see which provided the best fit for each rate class and region. The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

3. RESIDENTIAL CUSTOMER ADDITIONS

The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of December 5th 2019, Provincial Medium Term Forecast: 20173 Run: 18, Table LTPF156 and LTPF157. The housing starts data was as follows:

Table A3-3: Housing Starts Data

Housing Type	2018	2019	2020	2021
SFD	11,163	9,480	9,063	7,957
MFD	29,694	36,246	28,789	26,933
Total	40,857	45,726	37,852	34,890

From the above housing starts forecast, the 2020P SFD growth rate is calculated as follows:

$$2020P\ SFD\ Growth\ Rate = \left(\frac{9{,}063}{9{,}480}\right) - 1 = -4.4\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

Table A3-4: Growth Rates

	2020P	2021F
SFD	-4.4%	-12.2%
MFD	-20.6%	-6.4%

The following table incorporates the FEI proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2019 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally the CBOC growth rates for 2020 are applied to the SFD and MFD proportions for 2020 in column F and G and for 2021 in column I and J.

Table A3-5: FEI Proportions of Actual Account Additions by SFD and MFD

	Internal Split		2019A			2020P			2021F		
Sub-Region	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
	A	B	C	D	E	F	G	H	I	J	K
Mainland											
Lower Mainland	40%	60%	3,218	1,273	1,945	1,217	1,545	2,762	1,069	1,445	2,514
Inland	79%	21%	2,656	2,105	551	2,012	438	2,450	1,766	410	2,176
Columbia	68%	32%	182	125	57	119	46	165	105	43	148
Revelstoke	96%	4%	65	62	3	59	2	61	52	2	54
Whistler	71%	29%	108	77	31	73	25	98	64	23	87
Vancouver Island	80%	20%	4,380	3,487	893	3,333	709	4,042	2,927	663	3,590
Total FEU			**10,609**	**7,128**	**3,481**	**6,814**	**2,765**	**9,579**	**5,983**	**2,586**	**8,569**

For example, the Lower Mainland 2021F SFD value of 1,069 (column I) is derived as follows:

- Lower Mainland 2019 Internal Split – SFD percentage = 40% (column A);

- Lower Mainland 2019 Actual additions = 3,218 (column C)

$$LML\ 2019\ Actual\ SFD = 40\%\ \times 3{,}218 = 1{,}273\ (column\ D)$$

$$LML\ 2020\ Projected\ SFD =\ -4.4\% \times 1{,}273 = 1{,}217\ (column\ F)$$

$$LML\ 2020\ Forecast\ SFD = -12.2\% \times 1{,}217 = 1{,}069\ (column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated as an average of the net customer additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland RS 2.

Table A3-6: Customer Additions for Lower Mainland RS 2

Year	Customers	Customer Additions	Average 2017-2019
2016	52,790		
2017	53,320	530	
2018	54,055	735	
2019	54,211	156	474
2020P	54,685		
2021F	55,159		

The three-year average additions was 474, so 474 net additions are forecast in each of 2020 and 2021.

$$2020P\ Customers = 2019\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2020P = 54{,}685 = 54{,}211 + 474$$

Identical calculations are completed for all regions and all small commercial rate schedules.

However, due to rate switching between the large commercial rate schedules (specifically RS 3 and RS 23), forecasting for these two classes was done as a group and then proportioned per 2019 customers distribution.

The following table shows how the Lower Mainland large commercial customer additions forecast was developed. Other regions are similar.

Table A3-7: Lower Mainland Large Commercial Customer Additions Forecast Development

		Customers					Proportion	
	Accounts	RS 3	RS 23	Total	Total	3 Yr. Average	RS 3	RS 23
		A	B	C	D	E	F	G
1	2016	3,903	1,292	5,195				
2	2017	4,111	1,225	5,336	141			
3	2018	4,575	1,144	5,719	383			
4	2019	5,347	505	5,852	133	219	200	19
5	2020P	5,547	524				200	19
6	2021F	5,747	543				200	19

For each actual year (rows 1-4) the rate class customers from columns A and B are summed in column C.

Aggregate customer additions are shown in column D.

The three year average customer addiitons is 219 and shown in column E, row 4.

The 2019 proportion is calculated from columns A-C on row 4.

For example, the RS 3 proportion is:

$$RS\ 3\ Proportion = \frac{5{,}347}{5{,}852} = 0.91$$

The proportion of the aggregate customer additions (219) assigned to RS 3 is then:

$$RS\ 3\ Customer\ Additions = 0.91\ \times 219 = 200$$

A similar calculation is performed for RS 23 to arrive at 19 customer additions.

On row 5 the 2020P customer additions for RS 3 are shown in column A and calculated as:

$$2020P =\ 5{,}547 = 5{,}347 + 200$$

The remaining calculations are similar.

5. RESIDENTIAL AND COMMERCIAL USE RATES

5.1 *THE EXPONENTIAL SMOOTHING METHOD*

FEI develops its use rate forecasts based on ten years of annual use rates by region and rate class. The UPC values are weather-normalized using the process set out in section 2 above.

The ten years of data is used to calculate the UPC forecast using ETS, as implemented in Microsoft Excel.

ETS is implemented as both a formula and "wizard" in Excel 2016. Intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in its software.

The UPC method for Lower Mainland RS 1 (residential) is demonstrated below. All residential and commercial use rate forecasts in all regions are developed using the same method.

5.1.1 Lower Mainland RS 1 UPC Example

The forecast UPCs for Lower Mainland RS 1 were calculated as follows:

Start with ten years of weather normalized annual UPCs:

LOWER MAINLAND	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
RATE1	99.8	97.1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1

In Excel, the new "forecast.ets()" function is used to calculate the 2020 and 2021 forecasts.

LOWER MAINLAND	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RATE1	99.8	97.1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	=FORECAST.ETS(L3,B4:K4,B3:K3,0,0)	

The resulting forecasts for 2020 and 2021 are shown:

LOWER MAINLAND	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RATE1	99.8	97.1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	93.8	93.3

These annual UPCs must be converted to monthly values for input into FIS and this is accomplished by considering actual monthly proportions from the past three years.

LOWER MAINLAND													
RATE1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017	14.3	11.4	12.0	8.7	5.1	3.3	2.6	2.7	3.4	6.6	11.5	14.8	96.4
2018	15.8	11.9	10.7	8.0	4.5	3.5	3.0	2.5	3.1	6.3	10.9	15.7	95.8
2019	14.5	11.5	9.8	7.1	4.4	3.2	2.7	2.6	3.4	6.8	10.3	15.9	92.1
RATE1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017	15%	12%	12%	9%	5%	3%	3%	3%	4%	7%	12%	15%	100%
2018	16%	12%	11%	8%	5%	4%	3%	3%	3%	7%	11%	16%	100%
2019	16%	13%	11%	8%	5%	3%	3%	3%	4%	7%	11%	17%	100%
Average	16%	12%	11%	8%	5%	3%	3%	3%	3%	7%	11%	16%	100%

In the preceeding table the first three rows show the actual weather normalized monthly UPC values. The second three rows show the proportions for each year along with the average proportion in the final row.

The average proportion is applied to the ETS forecast to establish the monthly forecast, as follows:

2020 UPC Forecast	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
93.8	14.70	11.49	10.73	7.82	4.62	3.27	2.71	2.58	3.27	6.50	10.77	15.33	93.8

Note that the total of 93.8 matches the 2020 ETS forecast above.

Due to the extraordinary circumstances related to COVID-19, FEI created a projected year for 2020 by replacing the forecast values with actual values for January through June. The monthly actual use rates are:

LOWER MAINLAND	Jan	Feb	Mar	Apr	May	Jun
2020 Actuals	14.72	12.88	12.02	7.73	4.54	3.62

These values replace the ETS forecast values for 2020 as follows:

LOWER MAINLAND	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2020 Projection	14.72	12.88	12.02	7.73	4.54	3.62	2.71	2.58	3.27	6.50	10.77	15.33	96.7

The updated annual forecast is 96.7.

The 2021 forecast is not adjusted, and is as follows:

2021 Forecast	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
93.3	14.62	11.43	10.67	7.78	4.59	3.26	2.70	2.57	3.25	6.47	10.71	15.24	93.3

Identical calculations are completed for all residential and commercial rate classes in all regions. The resulting monthly values are entered into FIS.

5.2 AMALGAMATION OF UPCS IN FIS

Once the use rates are seasonalized and developed for each region and each rate schedule (RS 1, RS 2, RS 3 and RS 23), they are entered into FIS. The amalgamated use rates are calculated using the following relationship:

$$Use\ Rate = \frac{\sum Volume}{\sum Accounts}$$

FIS calculates both the monthly volume and accounts by region and rate class. In an external spreadsheet the volumes and accounts are summed by month and by rate class for all regions.

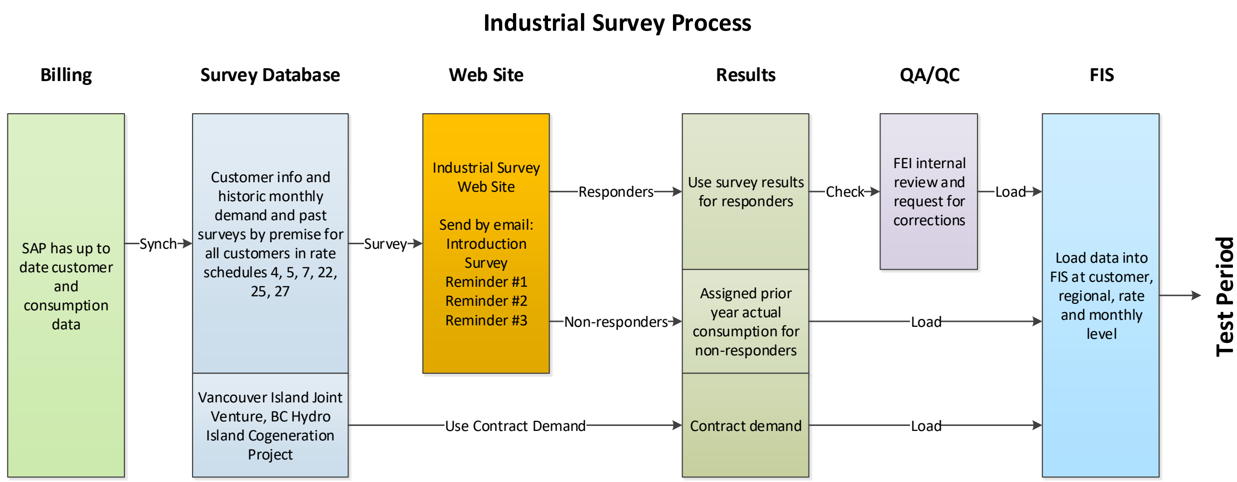
6. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast at the sub-regional level. The sub-regions, regions and months are then summed to arrive at the amalgamated demand forecast.

7. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure A3-2: Industrial Forecast Process



Each customer in each industrial class receives a customized email message with a secure link to their individual survey. The customer then uses the web based survey to complete their forecast of demand for the next five years and submits it to FEI. Once the survey is closed (typically after six weeks duration), the survey responses are checked and then the data is loaded into the FIS system. The following sections describe the process in detail.

7.1 CREATE THE SURVEY

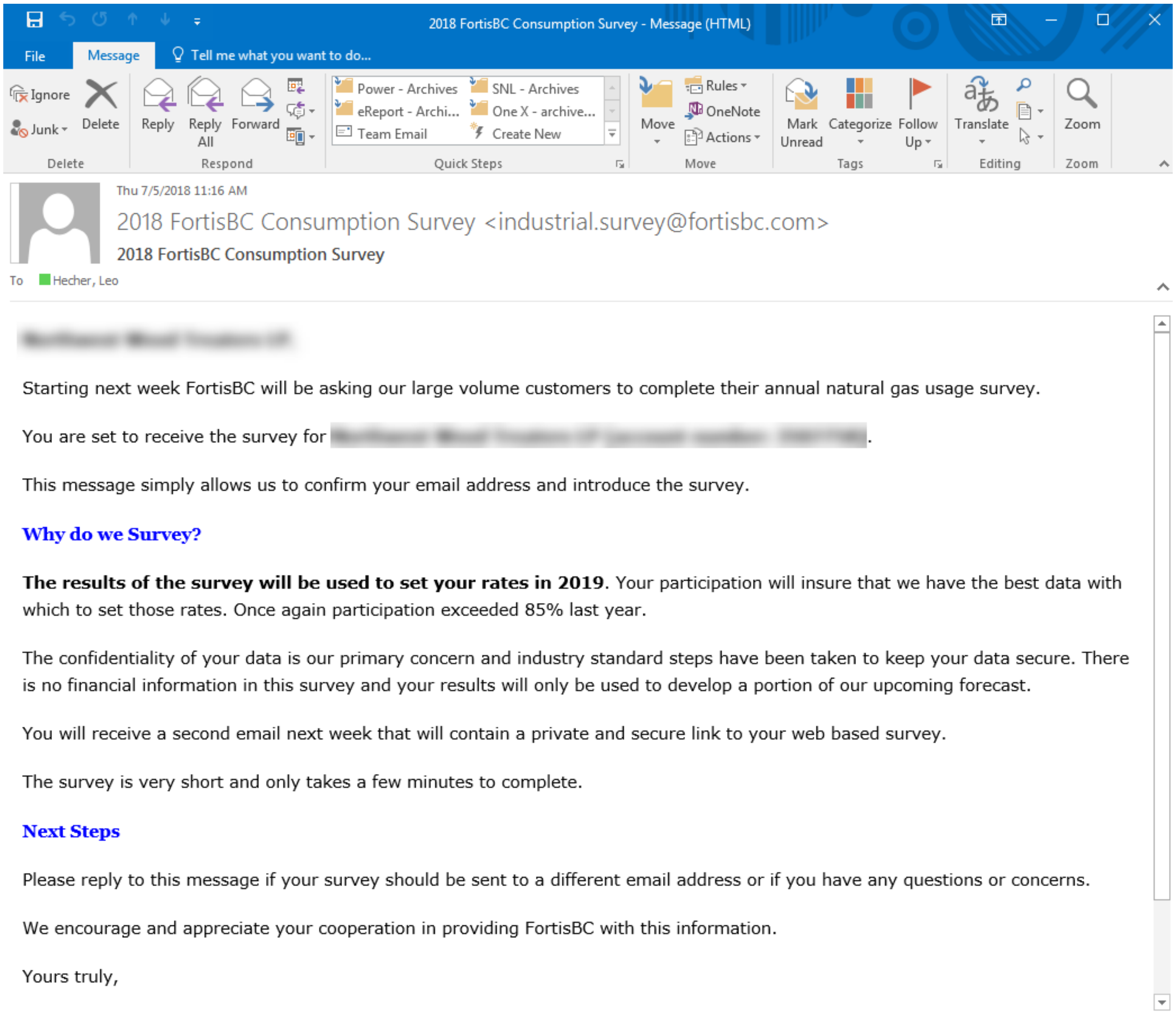
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

7.2 SEND OUT THE INTRODUCTION EMAIL

The customer is introduced to the survey several days before the actual surveys are sent out. This allows the customer time to update their contact information and possibly to assign the survey to a different employee if there have been staffing changes. FEI has found this to be an important step and contributes to the high success rate because a minimal number of surveys are sent to the wrong person.

The survey web site creates the form letters and manages the send out. The following is an example of the introductory email.

Figure A3-3: Survey Introductory Email Example



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 11:16 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

To Hecher, Leo

[redacted]

Starting next week FortisBC will be asking our large volume customers to complete their annual natural gas usage survey.

You are set to receive the survey for [redacted].

This message simply allows us to confirm your email address and introduce the survey.

Why do we Survey?

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Once again participation exceeded 85% last year.

The confidentiality of your data is our primary concern and industry standard steps have been taken to keep your data secure. There is no financial information in this survey and your results will only be used to develop a portion of our upcoming forecast.

You will receive a second email next week that will contain a private and secure link to your web based survey.

The survey is very short and only takes a few minutes to complete.

Next Steps

Please reply to this message if your survey should be sent to a different email address or if you have any questions or concerns.

We encourage and appreciate your cooperation in providing FortisBC with this information.

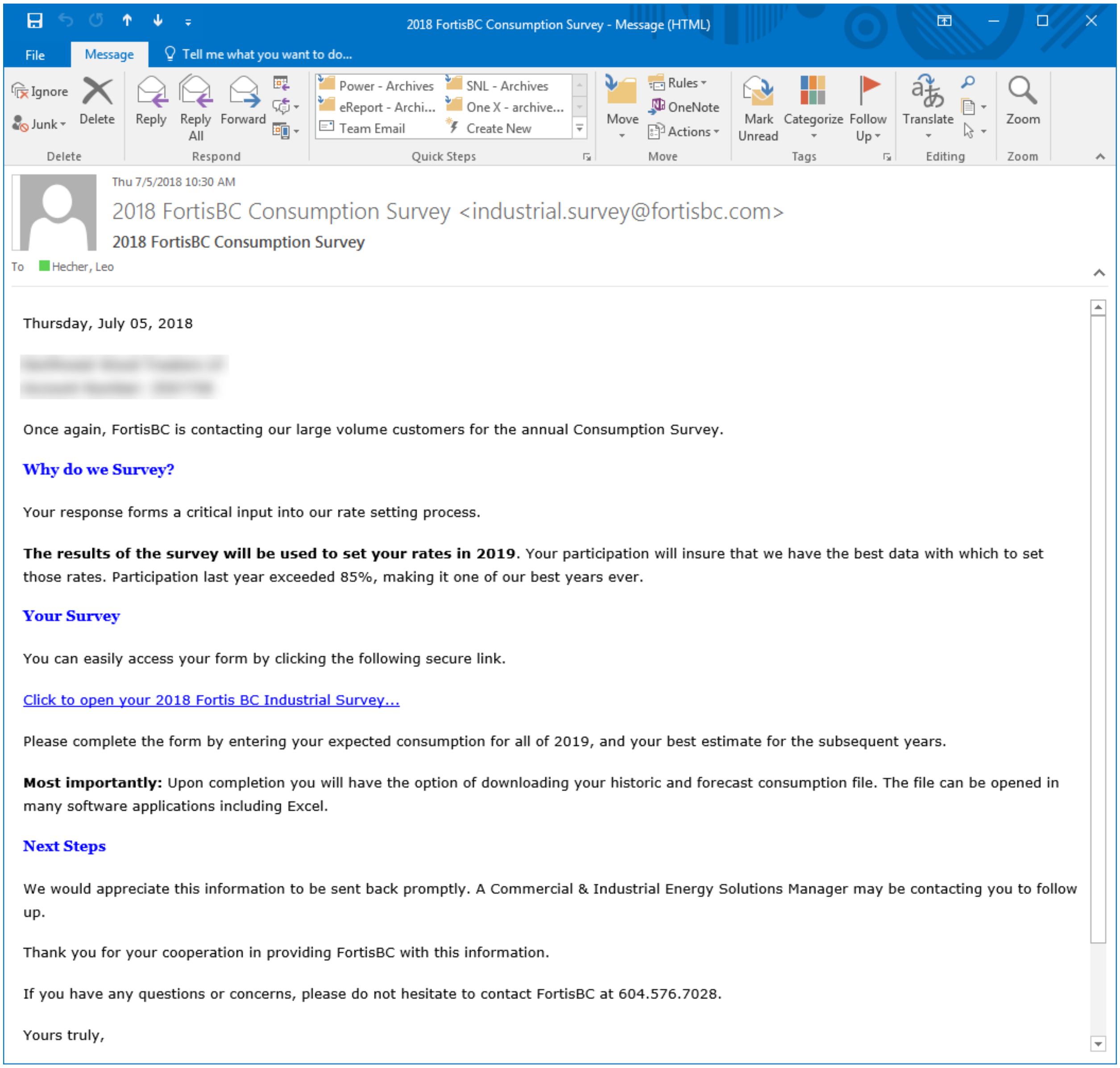
Yours truly,

Replies to these emails are used to update the contact and other information in the survey web site.

7.3 *SEND OUT THE SURVEY EMAIL*

An email with a customized link to the survey is sent out several days after the reminder. The survey is not sent until all the changes that resulted from the introductory email have been processed. As in the following sample email, each customer is sent an HTML link to the survey. An encrypted globally unique identifier in the link insures that customers cannot access surveys from other customers.

Figure A3-4: Survey Email Example



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 10:30 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

To Hecher, Leo

Thursday, July 05, 2018

Once again, FortisBC is contacting our large volume customers for the annual Consumption Survey.

Why do we Survey?

Your response forms a critical input into our rate setting process.

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Participation last year exceeded 85%, making it one of our best years ever.

Your Survey

You can easily access your form by clicking the following secure link.

Click to open your 2018 Fortis BC Industrial Survey...

Please complete the form by entering your expected consumption for all of 2019, and your best estimate for the subsequent years.

Most importantly: Upon completion you will have the option of downloading your historic and forecast consumption file. The file can be opened in many software applications including Excel.

Next Steps

We would appreciate this information to be sent back promptly. A Commercial & Industrial Energy Solutions Manager may be contacting you to follow up.

Thank you for your cooperation in providing FortisBC with this information.

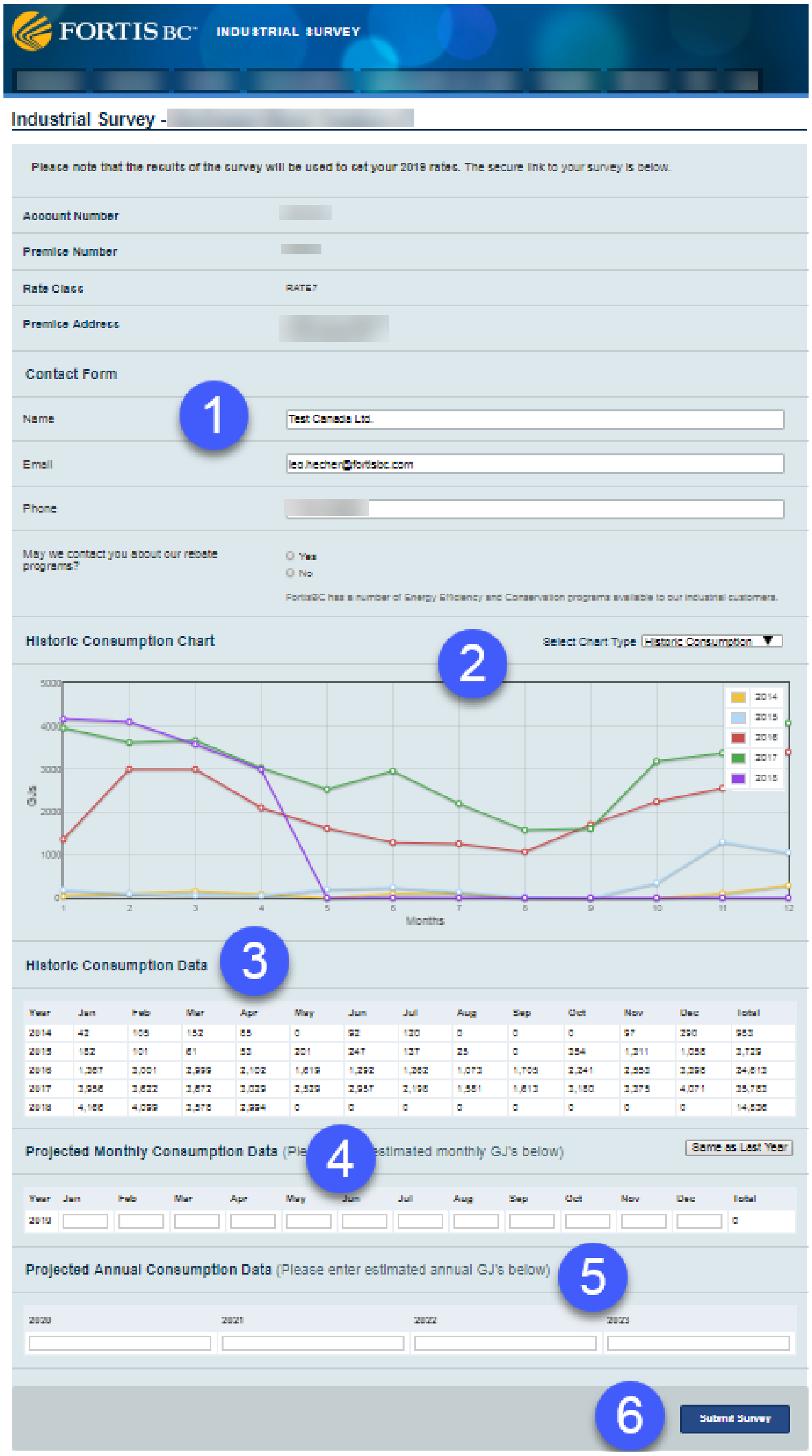
If you have any questions or concerns, please do not hesitate to contact FortisBC at 604.576.7028.

Yours truly,

7.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

1 **Figure A3-5: Survey (Web) Form Example**



FORTIS BC INDUSTRIAL SURVEY

Industrial Survey -

Please note that the results of the survey will be used to set your 2019 rates. The secure link to your survey is below.

Account Number	
Premise Number	
Rate Class	RATE7
Premise Address	

Contact Form

Name	Test Canada Ltd.
Email	leo.hecher@fortisbc.com
Phone	
May we contact you about our rebate programs?	Yes / No FortisBC has a number of Energy Efficiency and Conservation programs available to our industrial customers.

Historic Consumption Chart

Select Chart Type Historic Consumption

Historic Consumption Data

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2014	42	105	152	85	0	92	120	0	0	0	97	290	983
2015	152	101	61	53	201	247	137	25	0	354	1,311	1,058	3,729
2016	1,387	3,001	2,999	2,102	1,619	1,292	1,282	1,073	1,705	2,241	2,553	3,398	24,613
2017	3,956	3,622	3,672	3,029	2,529	2,957	2,198	1,581	1,613	3,150	3,375	4,071	35,763
2018	4,166	4,099	3,575	2,994	0	0	0	0	0	0	0	0	14,836

Projected Monthly Consumption Data (Ple... estimated monthly GJ's below) Same as Last Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2019													0

Projected Annual Consumption Data (Please enter estimated annual GJ's below)

2020	2021	2022	2023

Submit Survey

2

Notes:

1) The user can change the contact name (normally a person's name), email and phone number. It is saved and will be used in subsequent years. This allows the recipient to redirect next year's survey.

2) A line chart showing the customer's actual historic consumption is shown for the prior 5 years. The customer can use the pick list to show a chart that shows last year's actual consumption and last year's survey. This allows the customer to see any variance in their survey from last year.

3) A table of historical consumption is shown for the prior five years. Zeroes are shown in this example because the survey database is not updated until the start of a real survey.

4) The customer is asked for monthly consumption for the coming year. The total at the right side is automatically updated to reduce typing errors. If the customer believes that its consumption is not changing they can use the "Same as last year" button as a fast alternative to typing in the same values.

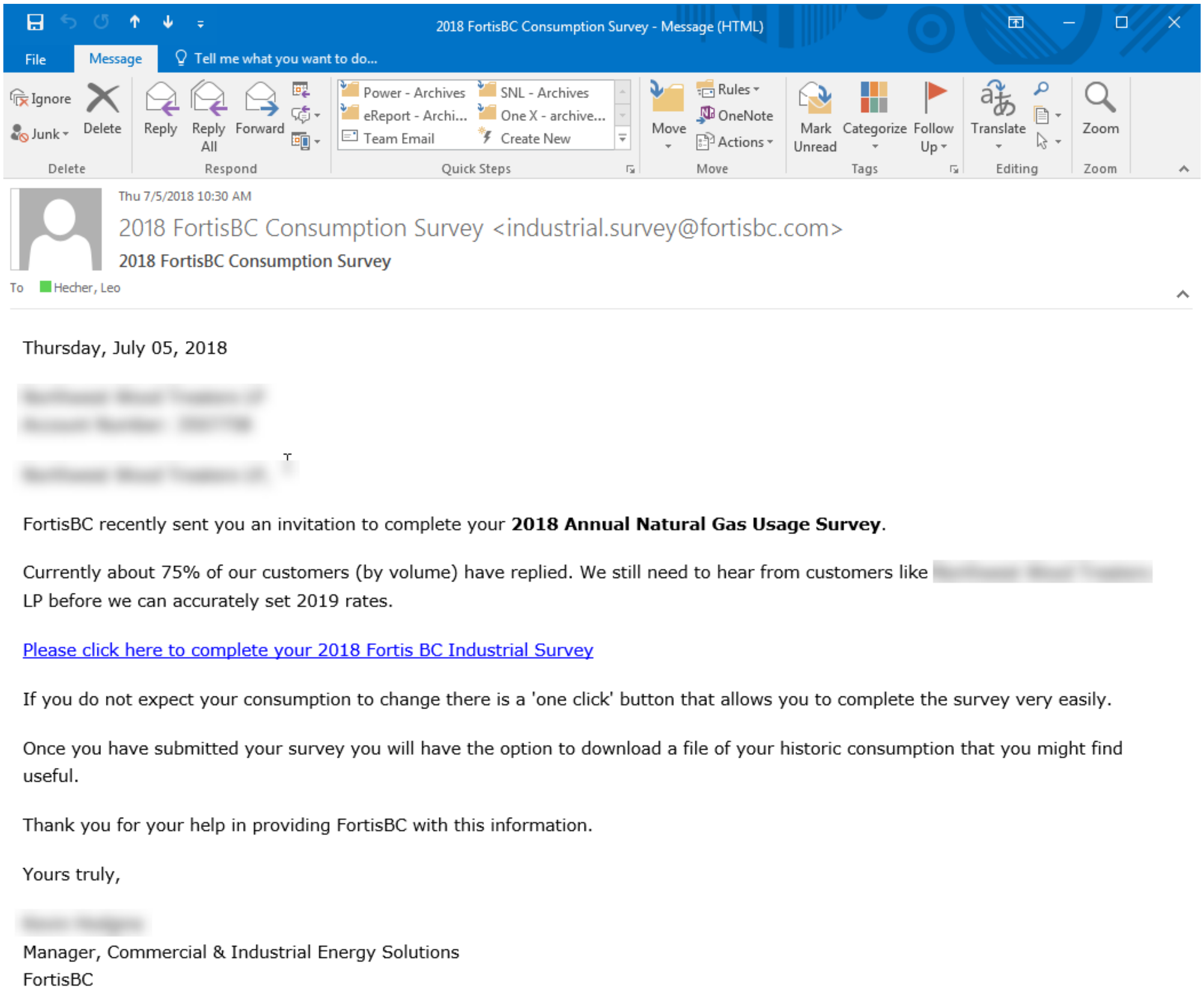
5) Annual forecasts are requested for the remaining 4 years of the survey.

6) Once the data has been entered the user clicks the Submit button to save the survey. Upon submitting the survey the user will be able to download a Microsoft Excel file containing the data from Step 3 above.

7.5 NON RESPONDERS AND THE REMINDER EMAIL

Once the survey is started, responses start coming in within the hour. A steady response rate normally continues for several days, but eventually slows. The survey system tracks the status of each survey and at all times FEI knows the response rate. Until the target response rate is reached, FEI sends out a weekly reminder email to those customers that have not yet responded. The reminder email contains the same link to the survey. The reminder step enhances the response rate of the survey. A sample is shown below:

Figure A3-6: Example of Survey Reminder Email



Thursday, July 05, 2018

[redacted]

FortisBC recently sent you an invitation to complete your **2018 Annual Natural Gas Usage Survey**.

Currently about 75% of our customers (by volume) have replied. We still need to hear from customers like [redacted] LP before we can accurately set 2019 rates.

Please click here to complete your 2018 Fortis BC Industrial Survey

If you do not expect your consumption to change there is a 'one click' button that allows you to complete the survey very easily.

Once you have submitted your survey you will have the option to download a file of your historic consumption that you might find useful.

Thank you for your help in providing FortisBC with this information.

Yours truly,

[redacted]
Manager, Commercial & Industrial Energy Solutions
FortisBC

7.6 *MONITORING THE RESPONSE RATE*

The response rate for the survey is measured in terms of number of respondents and the volume from those respondents. FEI is not only concerned with the number of customers that reply but also the volume those customers represent. The response rate from a volumetric perspective is always higher than the customer count response rate because large customers (for example those in RS 22) are more likely to reply to the survey.

The response rate is measured by counting the number of responses vs the number of customers in the survey. Some customers will not respond because the survey has been sent to an invalid email address and in these cases FEI attempts to correct the address so that a survey can be completed. FEI notes that if an address cannot be corrected during the time of the survey, then the customer remains in the denominator of the response calculation ratio.

The following screen shot is for demonstration purposes only.

Figure A3-7: Example of Survey Results Dashboard

7.7 *REVIEWING THE SURVEYS*

Surveys from large volume customers in RS 22 and RS 27 are reviewed by the Forecast Manager and two Commercial and Industrial Energy Solutions Managers. The Commercial and Industrial Energy Solutions Managers are well informed about the issues with each individual customer and are able to rationalize the survey received from the customer. Where surveys are contrary to the information the Commercial and Industrial Energy Solutions Managers have, a follow up call is made and the survey is adjusted if required.

7.8 *CLOSING OFF THE SURVEY AND LOADING FIS*

Once the target response rate has been achieved, the survey is closed and no further responses are solicited. The data in the survey web site is then transferred automatically to the current forecast in FIS. Industrial rate classes are forecast by individual customer so the data for each customer is copied. Checks are completed to make sure that that data was copied properly and that the survey web site and that the current FIS forecast are in sync.

Customers that do not respond to the survey are assigned their prior year's consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

8. SUMMARY OF DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month, region and rate class to prepare the overall forecast of demand.

Appendix B

FEI 2021 CMAE BUDGET REVIEW

FEI 2021 CORE MARKET ADMINISTRATION EXPENSE (CMAE) BUDGET REVIEW

1.1 *INTRODUCTION*

The CMAE budget funds the costs that FEI's Gas Supply Department incurs to plan, manage and optimize the commodity and midstream gas supply portfolios, mitigate unneeded resources, manage the credit exposure to counterparties, and minimize the impact of unfavourable upstream regulatory developments. As these activities are performed to serve core market customers, the CMAE budget is recovered separately from delivery costs through gas cost recovery rates.[1] FEI's 2016-2019 Actual, 2020 Projected and 2021 Forecast CMAE budget is set out in Schedule 1 to this appendix, in the format prescribed in Appendix B to Order G-23-15.

As set out in the Approvals Sought (Section 1.2, item 7 of the Application), FEI is requesting BCUC approval of the following, effective January 1, 2021:

- Approval of the 2021 CMAE Budget of $5.524 million, as set out in Schedule 1; and
- Approval of the allocation of the 2021 CMAE between the Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

Pursuant to the BCUC's Decision and Order G-79-14 regarding FEI's 2014 CMAE Budget (the 2014 CMAE Decision), the BCUC determined that the appropriate review process for the CMAE budget is as part of FEI's revenue requirements applications. However, as FEI was entering a multi-year Performance Based Ratemaking Plan (the 2014-2019 PBR Plan) at that time, the BCUC directed FEI to submit its CMAE budgets separately to the BCUC at least two weeks prior to the fourth quarter gas cost report until such time as FEI filed its next revenue requirements application.

In FEI's next revenue requirements application, the MRP Application[2], it was noted that due to the anticipated timing of a decision on the MRP Application, FEI would be filing for interim 2020 delivery rates in the fourth quarter of 2019, separate from the annual review process, which would occur after a decision on the MRP Application. As a result, for the 2020 CMAE budget, FEI continued with the process of filing for approval of the CMAE budget two weeks prior to the filing of the FEI Fourth Quarter Gas Cost Report.

[1] The Gas Supply department is primarily funded through the CMAE budget. However, activities not directly related to the commodity and midstream portfolio functions, such as the on-system transportation work supporting the transportation services business are included in O&M costs and recovered in delivery rates to be recovered from all non-bypass customers.

[2] Appendix B4 – FEI Review of CMAE Budget for the MRP Application.

Commencing with the 2021 CMAE budget, FEI is filing for approval of the CMAE budget as part of the Annual Review filings.

The following provides background on the CMAE as well as an explanation of FEI's 2020 Projected and 2021 Forecast CMAE budget.

1.2 *DESCRIPTION OF CMAE BUDGET*

The central purpose of activities funded by CMAE is to provide safe, reliable and cost effective gas supply resources that are required to meet core customers' load demands.

The CMAE budget is required for FEI staff and resources that are necessary:

- to plan and optimize gas supply requirements and to prepare FEI's Annual Contracting Plans;
- to manage the gas supply resources on a daily basis and mitigate any unneeded resources;
- to establish appropriate contracts with counterparties and manage the credit exposure;
- to manage upstream regulatory developments so that unfavourable outcomes are minimized, and opportunities are identified that can provide benefits to customers; and
- to complete the support activities related to regulatory and financial reporting and other compliance requirements.

Carrying out these responsibilities is critical given that the gross cost of the commodity and midstream gas supply portfolios is currently in excess of $600 million per year, and can change dramatically with changes in commodity costs or in transportation and storage costs. An important part of developing the gas supply portfolios is the evaluation of resources available to meet both normal and peak day core load requirements. This includes: support activities such as portfolio modelling and resource assessment; regional supply and demand analysis; discussions and meetings with pipeline and storage operators; maintaining strong relationships with gas producers and marketers; negotiation and administration of commodity, pipeline and storage contracts; staying on top of new regional infrastructure developments; and seeking opportunities for contracting resources related to cost effective pipeline or storage capacity expansions or additions. Successful mitigation activities performed by gas supply, for which specialized expertise is needed, can also result in several millions of dollars in incremental revenue that offsets the overall cost of gas for the benefit of customers.

The level of the CMAE budget is determined by the scope of work required to meet the responsibilities described above, which may increase or decrease year over year. For example, the CMAE budget may increase in a year when significant upstream regulatory developments require intervention in proceedings to ensure the interests of customers are protected.

The CMAE activities are provided on the basis of a common administrative function and the costs are then allocated between the gas supply commodity and midstream portfolios. The costs are allocated 30 percent to the CCRA and 70 percent to the MCRA to reflect the level of work performed by employees in the Gas Supply area to support each of the portfolios.

The table below provides a summary of the 2019 Actual, 2020 Approved, 2020 Projected and 2021 Forecast CMAE amounts, and Schedule 1 included in this appendix provides further details.

Table B-1: CMAE Summary ($ millions)

	Actual 2019	Approved 2020	Projected 2020	Forecast 2021
Labour	2.637	2.957	2.724	3.041
Non-Labour	1.495	1.670	1.903	1.797
Shared Services	0.686	0.686	0.686	0.686
Total CMAE	**4.818**	**5.313**	**5.313**	**5.524**

1.3 *REGULATORY TREATMENT OF CMAE*

The forecast CMAE costs are included as a component of the forecast gas costs for the purposes of determining the commodity and midstream (storage and transport) cost recovery charges.

The CMAE costs are allocated between the Company's CCRA and MCRA deferral accounts based on the approved allocation percentages of 30 percent and 70 percent, respectively. These allocation percentages continue to appropriately reflect the levels of gas supply efforts required to support the commodity and midstream functions.

Variances between the actual gas costs incurred and the forecast gas costs embedded in recovery rates are captured in the gas cost deferral accounts and, subject to BCUC approval, these variances are refunded to or recovered from customers as part of future commodity and midstream rates.

At the end of each year, the Company files its gas cost status report with the BCUC, which provides a summary of the cost and recovery variances and provides explanations for any material variances. The actual year-end 2020 CMAE costs and variances to the approved budget will be submitted, in the format prescribed by the BCUC, as part of the FEI 2020 CCRA and MCRA Status Report due to be filed by April 30, 2021.

1.4 *PROJECTED 2020 CMAE COSTS*

Schedule 1 has been prepared in the prescribed format of Appendix B to Order G-23-15. The schedule presents the 2020 Approved and 2020 Projected CMAE annual amounts, including variances and explanations. As well, Schedule 1 provides a summary of the Actual 2016-2019 CMAE costs, and the 2021 Forecast CMAE budget.

The year-end costs shown in the 2020 Projected column in Schedule 1 are based on the actual costs incurred to June 30, 2020 and the projected costs for the remainder of the year. As is shown in Schedule 1, there are variances between 2020 Approved and 2020 Projected CMAE amounts at the individual cost component level; however, the Company projects that overall the 2020 CMAE costs will total $5.313 million, which is the same as the 2020 Approved amount. Schedule 1 includes explanations of variances, at a cost component level, between the 2020 Approved and 2020 Projected CMAE amounts.

The Company submits that the year-end 2020 Projected CMAE costs, including all variances at the cost component level from the 2020 Approved CMAE budget, reflect the prudent and effective management of commodity and midstream gas supply costs for the benefit of customers. Consistent with past practice, the actual costs will flow through to customers as part of future commodity and midstream rates.

1.5 *FORECAST 2021 CMAE COSTS*

As reflected in Schedule 1 in the 2021 Budget Request column, the Company is seeking approval for the 2021 CMAE budget in the amount of $5.524 million, which is $0.211 million higher than 2020 Approved. The increase from 2020 Approved is primarily related to inflation based on the forecast labour and non-labour inflation factors. As well, forecast changes in the service / activity levels related to various non-labour components have been included. Explanations of the 2021 CMAE budget by cost component follow.

1.5.1 Information Systems (IS)

The Forecast 2021 Information Systems (IS) budget of $0.514 million is $0.084 million higher than 2020 Approved. As discussed in Schedule 1, 2020 and 2021 continue to be transition years related to the replacement of the current Entegrate deal capture system with a new Energy Trading and Risk Management (ETRM) system. During the transition period, software maintenance and support costs will be incurred on both systems until the new system is fully functional and the Entegrate system can be retired. Further, FEI will experience a reduction in the cost savings it was receiving related to sharing some of the Entegrate support costs with FortisBC Midstream Inc. (FMI) / Aitken Creek Gas Storage ULC (ACGS), as FMI / ACGS transitioned its business functions to the new ETRM platform in early 2020.

1.5.2 Consulting and Legal

The Consulting and Legal budget of $0.625 million is based on the forecast of upstream regulatory work anticipated to occur in 2021. These upstream regulatory matters engage FEI's interest in maintaining its ability to transact for gas supply at fair market prices, as well as reviewing costs that are reflected in fixed transportation tolls. The Company's participation in such proceedings, either directly or as a member of the Western Export Group (WEG), provides significant benefit to our customers, as commodity purchases at fair market prices and increases to the upstream pipeline tolls and tariffs directly impact FEI's rates.

Upstream regulatory matters are difficult to forecast as they are driven by third party applications to national regulators (the Canada Energy Regulator (CER) in Canada and the Federal Energy Regulatory Commission (FERC) in the United States), who determine the scope and timeline of any review. The nature of these applications, and issues they potentially create, drives the scope of FEI's involvement, ranging from simple monitoring to full participation in oral hearings. The costs incurred by this involvement are, as a result, highly variable. To help manage the costs of this involvement, FEI is a member of the WEG, which shares costs relating to matters concerning TC Energy's NOVA Gas Transmission Ltd. (NGTL) and Foothills BC systems.

1.5.3 Subscriptions & Memberships

The 2021 Forecast for Subscriptions & Memberships of $0.558 million has increased compared to 2020 Approved. The budget is based on the forecast costs for the required service levels and continues to include savings related to sharing the costs of some subscriptions with FMI / ACGS. The 2021 Forecast includes inflationary increases to the various subscriptions and membership dues, as well as the forecast increases that are in excess of inflation for contract renewals related to subscriptions for commodity price services.

1.5.4 Sundries

The 2021 Forecast for Sundries of $0.040 million has remained unchanged from the 2020 Approved amount and includes the forecast regulatory proceeding costs related to BCUC gas supply applications during the year, recurring expenditures for facilities communications and data charges, and other miscellaneous costs.

1.5.5 Training & Travel

The 2021 Forecast for Training & Travel of $0.060 million has decreased from the 2020 Approved and reflects the expectation of continued reduced travel for at least part of the coming year due to the COVID-19 pandemic.

1.5.6 MoveUP Labour

The 2021 Forecast for MoveUP Labour of $0.627 million has increased compared to 2020 Approved as a result of labour inflation. The 2021 Forecast is based on the labour inflation and benefits loadings.

1.5.7 M&E Labour

The 2021 Forecast for M&E Labour of $2.414 million has increased compared to 2020 Approved as a result of labour inflation. The 2021 Forecast is based on the forecast of labour inflation and benefits loadings.

FEI expects to continue to provide support to FortisBC Inc. (FBC) electric resource planning related functions during 2021. To reflect this support, the 2021 Forecast includes the cross-charging of approximately 30 percent of a full-time equivalent (FTE) from the gas supply labour resource pool to FBC. This provides benefits to both FEI and FBC. FEI is able to reduce its CMAE costs during a period that the level of price risk management activities within its portfolio remains lower than the historical level, while still being able to fully retain all of its skilled workforce. At the same time, FBC is able to access skilled labour resources, to enable it to accomplish its power resource planning work, at a reasonable cost.

1.5.8 Shared Services

The 2021 Forecast for Shared Services of $0.686 million has remained unchanged from the 2020 Approved and reflects the 2021 service level requirements. The Shared Services charge relates to the transfer of costs for services provided to Gas Supply from other areas of the business. The Shared Services include the provision of management oversight, core customer load forecasting, office workspace and technology requirements, and internal legal, tax and treasury support for counterparty contracts and credit analysis.

1.6 *SUMMARY*

The Company has examined its requirements for 2021 and forecast its CMAE costs accordingly. The 2021 Forecast CMAE Budget is required to ensure that the Company is able to prudently and effectively manage commodity and midstream gas supply costs for the benefit of customers.

Schedule 1

Line #	CMAE Cost Component	2016	2017	2018	2019	2020					2021
2	($000, unless specified otherwise)	Actual	Actual	Actual	Actual	Approved	Projected	Variance	Variance %	Variance Explanation	Budget Request
3	IS (Information Systems)	249	274	311	342	430	482	52	12%	Computer costs higher due to ongoing transition phase for new Energy Trading and Risk Management System (ETRM) and relates directly to overlap of software maintenance and support costs, and the foreign exchange rate increase.	514
4	Consulting & Legal	712	305	363	523	660	810	150	23%	Consulting and Legal costs higher due to review of various new gas supply commodity and transportation contracting arrangements, and non-capital support for the transition to the new ETRM system. Uncertainty related to the timing of the Consulting and Legal work may result in some projected 2020 costs being incurred in 2021.	625
5	Subscriptions & Memberships	315	305	287	395	420	526	106	25%	Subscriptions and Memberships costs higher due to the cost of the required subscription services and the foreign exchange rate increase.	558
6	Sundries	67	31	1,432	110	40	40	-	0%		40
7	Training & Travel	98	95	119	125	120	45	(75)	-63%	Lower than budget as result of travel restrictions related to COVID-19 situation.	60
8	MoveUP Salaries before Benefits & Incentives	426	463	445	445	435	466	31	7%	MoveUP Salaries higher due to upgrouping related to M&E backfill and higher estimated timebank accrual.	451
9	MoveUP Benefits (3)	191	143	152	166	173	176	3	2%		176
10	MoveUP Incentives (3) (4)	5	-	-	-						
11	M&E Salaries before Benefits & Incentives	972	1,213	1,349	1,268	1,523	1,337	(186)	-12%	M&E Salaries lower due to temporary backfill of M&E position using MoveUP resources, temporarily unfilled positions during the year, and increased cross charge to FBC Electric Resource Plan. Benefits lower due to lower salary costs.	1,569
12	M&E Benefits (3)	477	425	463	469	826	745	(81)	-10%		845
13	M&E Incentives (3)	199	208	215	289						
14	Energy Management Service Revenue	-	-	-	-	-	-	-			-
15	Shared Services	781	758	632	686	686	686	-	0%		686
16	**Total**	4,492	4,220	5,768	4,818	5,313	5,313	-	0%		5,524

17

18	CMAE FTE	2016	2017	2018	2019	2020					2021
19	(Number)	Actual	Actual	Actual	Actual	Approved	Projected	Variance	Variance %	Variance Explanation	Budget Request
20	MoveUP	5.4	5.3	4.9	4.9	5.0	5.0	(0.0)	0%		5.0
21	M&E	12.9	13.5	13.8	14.4	15.0	14.0	(1.1)	-7%	Temporary backfill of M&E position using MoveUP resources and temporarily unfilled positions during the year.	15.0
22	**Total**	18.3	18.8	18.7	19.3	20.0	18.9	(1.1)	-5%		20.0

23

24	Comparative Labour Loading	2016	2017	2018	2019	2020					2021
25	(percentages, except for salaries which is $000)	Actual	Actual	Actual	Actual	Approved	Projected	Variance	Variance %	Variance Explanation	Budget Request
26	Company-wide MoveUP Benefits as percentage of salaries (1)	46%	33%	30%	38%						
27	Company-wide MoveUP Incentives as percentage of salaries (1) (4)	1%	0%	0%	0%						
28	Subtotal Company-wide MoveUP Benefits & Incentives as percentage of salaries (1) (3)	46%	33%	30%	38%	40%	40%	-	-		40%
29	Company-wide M&E Benefits as percentage of salaries (1)	38%	31%	34%	32%						
30	Company-wide M&E Incentives as percentage of salaries (1) (4)	14%	15%	15%	17%						
31	Subtotal Company-wide M&E Benefits & Incentives as percentage of salaries (1) (3)	53%	46%	49%	49%	51%	51%	-	-		51%
32	CMAE MoveUP Salaries before cross-charging (2)	$ 428	$ 431	$ 428	$ 437	$ 434	$ 436				$ 446
33	CMAE MoveUP Benefits as percentage of salaries before cross-charging (2)	45%	33%	35%	38%						
34	CMAE MoveUP Incentives as percentage of salaries before cross-charging (2) (4)	1%	0%	0%	0%						
35	Subtotal CMAE MoveUP Benefits & Incentives as percentage of salaries (2) (3)	46%	33%	35%	38%	40%	40%	-	-		40%
36	CMAE M&E Salaries before cross-charging (2)	$ 1,292	$ 1,358	$ 1,435	$ 1,513	$ 1,627	$ 1,480				$ 1,667
37	CMAE M&E Benefits as percentage of salaries before cross-charging (2)	37%	31%	32%	31%						
38	CMAE M&E Incentives as percentage of salaries before cross-charging (2) (4)	15%	15%	15%	19%						
39	Subtotal CMAE M&E Benefits & Incentives as percentage of salaries (2) (3)	52%	47%	47%	50%	51%	51%	-	-		51%

Notes: Canadian Office and Professional Employees Union, Local 378 (COPE) known as Movement of United Professionals (MoveUP).

(1) Company-wide Salaries have been adjusted for items not attracting benefit loading such as overtime, premiums, retiring allowance, temporary MoveUP employee salary, and other adjustments.

(2) CMAE Salaries before cross-charging have been adjusted for items not attracting benefit loading such as overtime, premiums, retiring allowance, temporary MoveUP employee salary, and other adjustments. 2020 Approved amounts (Lines 32 & 36) have been restated to exclude AV Differential.

(3) Approved, Projected, and Budgeted Benefits & Incentives are included in a single labour loading rate based on budgeted amounts; breakdown is not available until after year-end.

(4) Data shown reflects incentive payments are made in the following fiscal year (e.g. 2018 payment amounts based on 2017 performance results). Effective April 1, 2015 MoveUP Gas employees no longer receive incentives.

Appendix C
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-79-14 – FEI 2014 Core Market Administration Expense (CMAE) Budget						
1.	10	2	CMAE Budget Review	The Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications. Therefore, until such time as FEI files its next revenue requirements application, the Panel directs FEI to submit future CMAE budgets separately to the Commission at least two weeks prior to the fourth quarter gas cost report to allow the Commission sufficient time to review the CMAE Budget, and to determine if there are sufficient variances from the previous CMAE Budget to warrant a more fulsome review. The Panel directs that the CMAE Budget review and approval process be included within the FEI revenue requirements application starting with the next such application by FEI.	Ongoing	Appendix B
G-237-18 – FEI Annual Review for 2019 Delivery Rates						
2.	8-9		TIMC Project	The Panel directs FEI to file the following information in its next revenue requirement application, which is expected to be filed sometime in 2019: 1. Updated actual and forecast project development costs compared to budget with explanations for variances; 2. Updated timeline for when FEI anticipates filing the CPCN with explanations for changes; and 3. Details on project scope and deliverables, including any changes thereto from what was provided in the current annual review proceeding.	Ongoing	Section 12.4.1.2

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-165-20 – FEI MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
3.	48	11	Setting the I-Factor	Based on these findings the Panel determines that the I-factor formula will be as follows: I = X $x\ AWE{:}BCt{-}1$ + Y $x\ CPI{:}BCt{-}1$ Where: • I = Inflation Factor • AWE:BC = labour index • CPI:BC = non - labour index • t - 1 = most recent July to June value • X = the previous year's labour ratio; and • Y = the previous year's non-labour ratio. FortisBC is directed to provide the results of the completed formula based on 2019 results for FEI and FBC to set the base for 2020 as part of its compliance filing. Thereafter, the formula will be informed by the previous year's results and reviewed as part of the Annual Review Process.	Completed.	Section 2.2
4.	75	24	General Flow-through Deferral Account	The Panel directs FEI to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term.	n/a for 2020 and 2021 as no amounts are forecast.
5.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). 4. FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No Approved ECM Initiative to report on.	n/a

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
6.	99-100	37	SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Transmission Reportable Incidents (number of reportable incidents to outside agencies) – FEI only. • Leaks per KM of Distribution System Mains (number of leaks on the distribution system per KM of distribution system mains) – FEI only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13
7.	115	40	Systems Operations, Integrity and Security Expenditures	The Panel directs FEI to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Integrity management; • Maintaining system infrastructure; • Operations compliance and safety; • Cyber security; • Data analytics; • Gas control; • Canadian Energy Pipelines Association (CEPA) participation; and • Any other significant factors or miscellaneous items. 2. A description of how FEI is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
8.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Will be filed in FEI's Annual Review for 2023 Rates	n/a
9.	157	62	Innovation Fund	The Panel further directs FEI to include progress preports on the operation of FEI's Innovation Fund and projects funded thereby.	Ongoing during the MRP term	Section 10.2.3.

Appendix D

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Annual Review for 2020 and 2021 Delivery Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-165-20 approving for FortisBC Energy Inc. (FEI) a Multi-Year Rate Plan (MRP) for 2020 through 2024 (MRP Decision). In accordance with the MRP Decision, FEI is to conduct an Annual Review process to set rates for each year;

B. By Order G-302-19, dated November 28, 2019, the BCUC approved a 2.0 percent delivery rate increase from 2019 delivery rates on an interim and refundable/recoverable basis, effective January 1, 2020, pending a decision on the MRP;

C. By letter dated July 20, 2020, FEI proposed a regulatory timetable for its annual review for permanent 2020 and 2021 delivery rates;

D. By Order G-209-20 dated August 10, 2020, the BCUC established the regulatory timetable and on August 12, 2020, FEI submitted its Annual Review for 2020 and 2021 Delivery Rates Application (Application);

E. In the Application, FEI's revenue requirements for 2020 result in a delivery rate increase of 3.27 percent from 2019 delivery rates. FEI requests approval to make the existing interim rates permanent, effective January 1, 2020, and to capture the revenue deficiency greater than the 2 percent delivery rate increase already incorporated in the interim rates in the existing 2017 & 2018 Revenue Surplus deferral account as an offset to prior years' revenue surpluses;

F. The Application also requests approval of a delivery rate increase of 6.59 percent from 2020 delivery rates, effective January 1, 2021, after drawing down the 2017 & 2018 Revenue Surplus deferral account which, after consideration of the delivery rate riders, results in an annual bill increase of approximately $29 or 3.4 percent for an average residential customer; and

G. The BCUC has reviewed the Application and evidence filed in the proceeding and considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons attached as Appendix A to this order, the BCUC orders as follows:

1. FEI's existing 2020 interim delivery rates are approved as permanent, effective January 1, 2020.

2. FEI's permanent delivery rate increase of 6.59 percent, effective January 1, 2021 is approved.

3. The following deferral account requests are approved:

    a. Creation of rate base deferral accounts for the following regulatory proceedings:

        i. The Annual Reviews for 2020 to 2024 Rates, with the costs of each annual review to be amortized in the subsequent year;

        ii. 2022 Long-Term Gas Resource Plan, with the amortization period to be determined in a future proceeding;

        iii. BCUC Initiated Inquiries, with balances to be amortized in the subsequent years; and

        iv. The City of Coquitlam Application Proceeding, to be amortized over three years beginning January 1, 2021;

    b. The previously approved 2020 Revenue Requirement Application deferral account is renamed to the 2020-2024 MRP Application deferral account, to be amortized over the five year period beginning January 1, 2021; and

    c. Draw down of the 2017 & 2018 Revenue Surplus deferral account in the amount of $10.338 million before tax in 2020 and $35.287 million before tax in 2021, which will bring the account balance to zero.

4. A Biomethane Variance Account Rate Rider for 2021 in the amount of $0.022 per gigajoule (GJ) as calculated in Section 10.2.1 is approved.

5. Revenue Stabilization Adjustment Mechanism riders for 2021 in the amount of $0.087 per GJ as calculated in Section 10.2.2 of the Application is approved.

6. FEI is approved to continue debiting of the Midstream Cost Reconciliation Account (MCRA) and crediting of Other Revenue in the amount of $300 thousand per month for the period of January 1, 2020 to October 31, 2020 as described in Section 5.3.2 of the Application.

7. Effective November 1, 2020, and for the duration of the MRP term, FEI is approved to debit the MCRA and credit Other Revenue in the amount of $346.617 per MMcfd, as described in Section 5.3.2 of the Application.

8. The 2021 Core Market Administration Expense (CMAE) budget of $5,524 thousand, as set out in Schedule 1 in Appendix B, and the continued allocation of the CMAE between FEI's Commodity Cost Reconciliation Account and MCRA based on the allocation percentages of 30 percent and 70 percent, respectively, is approved.

9. FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account as discussed in Section 12.2.1 of the Application.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner