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August 3, 2018

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

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-138-14 (the PBR Plan)

Annual Review for 2019 Delivery Rates

In accordance with the PBR Plan and Commission Order G-143-18 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2019 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 FEI's Annual Reviews for 2018 Delivery Rates

FortisBC Energy Inc.

Multi-Year Performance Based Ratemaking Plan

for 2014 through 2019

Annual Review for 2019 Delivery Rates

Volume 1 - Application

August 3, 2018

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1. APPROVALS SOUGHT, OVERVIEW OF APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Energy Inc. (FEI or the Company) files this Application in compliance with British Columbia Utilities Commission (the Commission) Order G-138-14, which approved a Performance Based Ratemaking Plan (PBR Plan) for FEI for the years 2014 to 2019. In accordance with the PBR Plan, an annual review process is required to set rates for each year under the PBR Plan. With the filing of this Application, FEI seeks to commence the fifth annual review of the PBR Plan and set FEI's delivery rates for 2019.

The PBR Plan approved by the Decision attached to Order G-138-14 (PBR Decision) increases FEI's incentives to seek out savings while maintaining service quality.[1] Pursuant to the earnings sharing approved by the Commission, savings in formula-driven O&M and capital expenditures achieved by the Company are shared equally with customers, as discussed in Section 10 of the Application.

Under the PBR Plan, FEI projects savings in 2018 due to a continuation of its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling of vacancies and a number of initiatives that result in net O&M and capital savings. Overall, FEI proposes to distribute $1.466 million[2] in earnings sharing to customers in 2019. FEI achieved these savings while maintaining a high level of service quality as indicated by meeting the Service Quality Indicators (SQIs) approved in the PBR Decision.

The proposed delivery rates for 2019 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 0.5 percent increase from 2018 delivery rates; however, FEI is proposing to maintain 2019 delivery rates at existing levels by amortizing a portion of the existing 2017 & 2018 Revenue Surplus deferral account to offset the 2019 revenue deficiency[3].

In the subsections below, FEI sets out the approvals it is seeking, provides an overview of the requirements for the annual review process, and provides an evaluation of the PBR Plan for 2018. This is followed by a summary of FEI's proposed revenue requirement and rate changes for 2019 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

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[1] PBR Decision, p. 138.

[2] This amount is pre-tax and includes both the estimated 2018 earnings sharing and adjustments related to 2017 actuals.

[3] Residential customers will experience a 0.3% decrease in their delivery rates due to a net reduction in delivery rate riders (Bio-methane rate rider 3 and RSAM rate rider 5) which equates to an annual burner-tip decrease of approximately 0.2% (based on 90 GJ per year consumption).

1.2 *APPROVALS SOUGHT*

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

1. Maintain 2019 delivery rates at approved 2018 levels[4], holding the delivery charge and basic charge at existing levels;
2. The following deferral account approvals as described in Sections 7.5 and 12.4:
    - Creation of a rate base deferral account for the 2019-2022 Demand Side Management Expenditures regulatory proceeding with a four-year amortization period.
    - Amendment of the existing rate base 2017 Long-Term Resource Plan Application deferral account to also capture the regulatory proceeding costs related to the Application, as well as a three-year amortization commencing in 2019.
    - A five-year amortization period for the existing 2017 Rate Design Application deferral account, commencing in 2019.
    - Creation of a non-rate base deferral account, attracting a weighted average cost of capital (WACC) return, for the development costs related to Transmission Integrity Management Capabilities (TIMC), with disposition to be proposed in a future application.
    - Partial amortization of the 2017-2018 Revenue Surplus account in the amount of $3.075 million, which will result in a total 2019 forecasted revenue deficiency/surplus of zero. FEI will provide a similar request in future applications until the balance in the account is drawn-down to zero.
3. A Biomethane Variance Account (BVA) Rate Rider for 2019 in the amount of $0.018 per gigajoule (GJ) as calculated in Section 10.2.1;
4. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2019 in the amounts set out in Table 10-10 in Section 10.2.2; and
5. The continued debiting of the Midstream Cost Reconciliation Account (MCRA) and crediting of the delivery margin revenue in the amount of $3.6 million for 2019, as described in Section 5.3.2.
6. Z-factor treatment for the 2019 Employer Health Tax and 2018 and 2019 MSP premium reductions, as described in Section 12.2 of the Application.
7. Approval to recognize cloud computing implementation costs to be capitalized consistent with traditional on premise hardware and software for 2019 as described in Section 12.3.1.2.

A draft order is included in Appendix D.

[4] After implementation of approved (G-135-18) rate design changes

FEI notes that the approvals sought above will be impacted by two other regulatory proceedings, one of which has concluded and the other is in progress.

1.2.1 Rate Design Decision Orders G-4-18 and G-135-18

On January 9, 2018 the BCUC issued Order G-4-18 and Reasons for Decision on FEI's proposed Cost of Service Analysis and Revenue to Cost ratios (COSA and R:C Ratios Decision). On July 20, 2018 the BCUC issued Order G-135-18 and Reasons for Decision on the balance of FEI's Rate Design Application which provided FEI 60 days from the date of the order to file its compliance filing.

Following the above noted compliance filing, FEI will incorporate the resulting rate changes into its 2019 Annual Review for Rates (this Application) with an evidentiary update.

1.2.2 2019 – 2022 Demand Side Management Application

On June 22, 2018, FEI filed its Application for Acceptance of 2019-2022 Demand Side Management Expenditures Plan (DSM Application) and on July 28, 2018 the Commission set out the regulatory timetable by which the approvals in this application would be determined. Approvals sought within the DSM Application include an increase in expenditures, an adjustment of the amount of expenditures allowed as a forecast within FEI's annual rate setting mechanism and a change to the amortization period of DSM expenditures, all of which will impact the 2019 forecasts within this Application. The regulatory timetable includes FEI's Reply Argument for the DSM Application on November 1, 2018. FEI anticipates that a decision may be received for the DSM Application by the end of 2018 and if so will incorporate the DSM Application decision in its compliance filing to this Application.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On pages 185 and 186 of the PBR Decision, the Commission set out its expectations for the Annual Review component of the PBR Plan, with one further directive (number 8 in the table below) provided on page 17 of Order G-120-15 in the Capital Exclusion Criteria compliance filing. For reference, the table below sets out each requirement and FEI's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns.	Section 1.4
2	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 2(a) to 2(g) below

Item	Description	Response or Reference
2(a)	Customer growth, volumes and revenues;	Section 3
2(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
2(c)	Expenses (determined by the PBR formula plus flow-through items);	Section 6
2(d)	Capital expenditures (as determined by the PBR formula plus flow-through items);	Section 7
2(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;	Sections 7 and 12
2(f)	Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and	Section 10
2(g)	Any proposals for funding of incremental resources in support of customer service and load growth initiatives.	FEI does not have any proposals at this time
3	Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives.	FEI has not identified any efficiency investments with a payback beyond the end of the PBR period that it is not pursuing
4	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers.	Section 12
5	Review of the Companies' performance with respect to SQIs. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service.	Section 13
6	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.	FEI does not have any recommendations for new SQIs or the discontinuation of SQIs at this time
7	Assess and make recommendations to the Commission on the scope for future Annual Reviews.	FEI does not have any recommendations at this time
8	Where the dead band is exceeded for any year, FEI and FBC are directed in the next Annual Review filing to include recommendations as to any adjustment to base capital other than those driven by the 1-X mechanism.	Dead band is projected to be exceeded for 2018. See section 1.4.4.

1.4 EVALUATION OF THE PBR PLAN

FEI has continued its productivity focus in 2018 and initiated additional projects to enhance the customer experience and improve productivity, in addition to the continuing initiatives from prior years. As a result of this focus and these initiatives, FEI was able to continue to realize savings in O&M expenditures above those embedded in the formula. FEI continues to be challenged to meet growth and maintain the system within the capital formula amount. Overall, the savings achieved result in $1.466[5] million of earnings sharing that will be returned to customers in 2019, serving to reduce overall delivery rates for FEI's customers. FEI's performance with respect to SQIs, as reported in Section 13 of the Application, demonstrates that FEI achieved the net savings while maintaining a high level of service quality.

1.4.1 Overview of O&M Savings

In 2018, FEI is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $5.0 million lower than the formula amount. Table 1-2 below shows the formula O&M savings for each year of the PBR Plan and the cumulative to date. The table also show the embedded Productivity Improvement Factor (PIF) savings for the same years. The table shows that in addition to the cumulative formula O&M savings of approximately $42.8 million to the end of 2018 which are shared with customers, the cumulative PIF savings to the benefit of customers total to approximately $12.7 million.

Table 1-2: Formula O&M Savings 2014 to 2018 ($ millions)

		Actual	Formula	Variance	1.1% PIF
	2014	$ 191.0	$ 198.5	$ 7.5	$ 2.2
	2015	$ 225.4	$ 235.6	$ 10.2	$ 2.6
	2016	$ 225.9	$ 238.1	$ 12.1	$ 2.6
	2017	$ 232.5	$ 240.4	$ 7.9	$ 2.6
*	2018	$ 238.6	$ 243.6	$ 5.0	$ 2.7
	Cumulative Savings			$ 42.8	$ 12.7

* 2018 is projected.

In 2018, as we near the end of the term of the current PBR Plan, FEI continues to be faced with the increasingly difficult challenge of finding new productivity opportunities to meet the annual savings embedded in the formula, and to sustain the level of incremental O&M savings achieved in recent years. As a result, the 2018 projected O&M savings of $5.0 million is lower than recent years, recognizing the impact of the PIF factor in the allowed annual O&M funding available. Contributing also to the productivity challenge are new cost pressures the Company is experiencing.

[5] This amount is pre-tax and includes both the 2018 estimated earnings sharing and adjustments related to 2017 actuals.

1.4.2 Staffing Levels

Staffing levels declined from 2013 to 2015, and remained relatively stable between 2015 and 2016. Staffing levels have increased in 2017 and are anticipated to increase further in 2018 in response to the company's Operational requirements, particularly in the Operations and Engineering areas to meet customer growth and other capital requirements. Of the 67 FTEs increase observed from 2016 (1,581 FTEs) to 2017 (1,648 FTEs), approximately 28 were in the Operations and Engineering area, including Tilbury LNG, in response to increased operational and capital work requirements; approximately 14 in the Contact Centre and Billing Operations resulting from the timing of new hire classes, with the remainder of the overall increase in various departments throughout the Company.

Table 1-3: Employees at Year-End[6]

	Headcount	FTEs
2013 Actual	1,764	1,679
2014 Actual	1,704	1,650
2015 Actual	1,656	1,573
2016 Actual	1,667	1,581
2017 Actual	1,735	1,648
2018 Projected	1,816	1,727

From 2013 to 2016, contributing to the overall decline in FTEs have been reductions in the Customer Service area as the result of a management reorganization and reductions in staffing related to lower call volumes, in part due to annual fluctuations in weather. Included in the Customer Service reductions also are positions related to Project Blue Pencil that occurred in 2015. These decreases are now being offset by increased staffing primarily in the Operations and Engineering area to meet operational and capital work requirements. FEI is growing and adding new assets that require maintenance to keep them operating safely and reliably. In addition, assets are aging and requiring additional maintenance and corrective work. Emergency calls, BC One Call tickets and activities around our pipelines are all increasing. Municipal agreements, codes, regulations, public expectation, and industry practices continue to evolve and drive additional work. New main and service installations are at high levels.

Additional headcount and FTE information as requested by the Commission in Order G-182-16 regarding FEI's Annual Review for 2017 Rates proceeding is provided in Appendix C-3.

[6] Figures provided are total FTEs and include FTEs that charge time to O&M, capital, deferral accounts, and Core Market Administration Expense. The FTEs are the average FTEs for the 12-month calendar year, consistent with other reporting provided to the Commission.

1.4.3 Major Initiatives Undertaken

In FEI's Annual Review for 2015 Rates, FEI provided information regarding two major initiatives that were undertaken in 2014 - the Regionalization Initiative and Project Blue Pencil. Directive 28 attached to Order G-86-15 regarding FEI's Annual Review for 2015 Rates stated:

> The Panel directs FEI to continue to provide in each annual review application the information that was provided in response to BCUC IRs 1.2.9 (Regionalization Initiative) and 1.3.3 (Project Blue Pencil) and to update these tables for actual results as this data becomes available. The same analysis is to be performed on new initiatives that are implemented during the PBR term.

FEI provides a summary below of the major initiatives undertaken or ongoing in 2018. A table for each initiative that has been implemented (initiatives 1 through 7 below) including a separate table for each phase of the Regionalization Initiative showing the requested information is provided in Appendix C2.

1. ***The Regionalization Initiative*** is aimed at both enhancing the customer experience and achieving a more efficient process in the field. In the first part of 2016, efforts continued on transitioning more functions to the regions. By the end of the first quarter of 2016, the Pre-requisition, Closing and Hazards functions were successfully transitioned into the regions. This phase represents the second phase of the Regionalization Initiative that began in 2014 with the transitioning of the Field Dispatch, and Planning and Design groups to the regional locations. The changes have enabled optimal decision making, and have been found to be more cost-effective and to serve customers better. As part of the Regionalization Initiative, detailed process reviews were undertaken and considerable streamlining achieved, which resulted in changes to workflow and a reduction in the number of hand-offs required to process work. The Regionalization Initiative improved the customer experience and made it easier for customers to conduct business with the Company. Technology was leveraged and adapted to improve the flow of job packages and get them to the resource assigned to complete the work.

   The first full year operating under a regional business model was 2015. Annual O&M savings in 2015 for the first phase were approximately $1.0 million compared to 2013 actuals. The second phase of the Regionalization Initiative in 2016 produced incremental annual O&M savings of approximately $1.1 million. FEI expects savings from both phases to be sustained in future years.

2. ***Project Blue Pencil*** is an initiative focused on reviewing and streamlining key customer-facing processes from the perspective of the customer. In 2014, a review was completed which found opportunities not only to improve the customer experience, but also to increase operational efficiencies at the same time. These improvements were completed in 2015, reducing operating costs in the contact center and billing operations departments by approximately $1 million annually as compared to 2013 actuals. In 2016, these operational savings have been sustained at approximately $1 million and are expected to continue into future years.

3. ***Review of Technical and Infrastructure Support Provider*** is an initiative to review the existing agreement with the Company's technical and infrastructure service provider. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. In 2015, FEI replaced its existing technical and infrastructure support provider with a new service provider, Compugen. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. For each permanent reduction in Compugen's costs to support FEI, the vendor and FEI share in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies. Additionally, the new contract provides dedicated support resources rather than a distributed support service, resulting in quicker response times and better understanding of the Company's requirements. When compared to 2015, savings in 2016 increased by $200 thousand to $2 million due to a full year of the lower cost Compugen contract as compared to 2015. Savings in 2017 were comparable to 2016 savings achieved. The Company expects the 2018 savings to be comparable to savings realized in recent years.

4. ***The Online Service Application (OSA) initiative*** enables customers to make a self-serve online request for a new service line installation and was launched on the Company's external website in September 2016. In March 2017, the additional functionality of requesting a service line abandonment was added to the tool. Customers can go to the Company's website and use the tool to determine if gas service is available for their property, and, for simple service lines, obtain an estimate to install the service and proceed to scheduling the installation online. The tool offers additional functionality for the builder/developer community to manage their projects by tracking their multiple service line orders. Annual savings were approximately $0.05 million in 2017 and future years.

5. ***SAP Integration*** is an initiative to integrate the FEI and FortisBC Inc. (FBC) SAP systems, moving towards a common SAP platform for both companies. It primarily includes the integration of the Human Resources, Supply Chain and Finance systems in SAP. The benefits will include a simplified support model, alignment of processes, simpler business processes (i.e. employee expense processing and single sign-on), reduced licensing costs and integrated payroll. Reduction in support costs will be achieved through reduced annual contractor costs because internal resources will be able to displace the contractor support due to the simplified support requirements.

   The project is in progress and is tracking well to the schedule, with completion expected in the third quarter of 2018. The total cost of the project remains on budget, estimated at $4.5 million. Based on the number of employees between the two companies, which is currently projected at approximately 77% FEI and 23% for FBC, approximately $3.5 million of the implementation costs will be allocated to FEI with the remaining $1.0 million to FBC. Total O&M savings for the project are expected to be approximately $0.9 million annually, with $0.6 million expected in FEI and $0.3 million FBC. The savings will start being realized in 2019.

6. ***Gas Workforce Management*** is a project to replace the current systems used to support the mobile requirements of FEI's Distribution field workforce. The Gas Workforce

Management project supports the business by focusing on safety, customer experience, operational excellence, and using technology wisely. The project will streamline and improve work processes, and replace Syclo, ClickSchedule, and Tensing Mobile GIS. The Syclo system has not been significantly upgraded since its implementation in 2008 and is at end of life. ClickSchedule and Tensing Mobile GIS are nearing end of life and due for replacement. Bundling these 3 systems will simplify the user experience while providing FEI with the flexibility for future growth and improvement.

The project is underway with completion expected in late 2019. The total cost of the project is estimated at approximately $6.5 million and will produce O&M savings of approximately $0.5 million annually starting in 2020.

7. ***Common Trenching*** is an initiative to improve the customer experience by introducing four-party trenching for new subdivisions and townhouse developments. Currently, FEI installs gas mains and services using internal or contractor resources. FEI is typically the last to install and construct its gas mains and services, after the final surface infrastructure (i.e. landscaping, pavement, curbs, and sidewalks) have been completed.

   In collaboration with other shallow utility owners, developers, and customers, FEI is currently developing a program to install gas mains and multi-family services in conjunction with other underground infrastructure such as electric, telephone, and cable conduit. By installing gas infrastructure early and concurrently, FEI is able to increase onsite safety and improve customer service by decreasing construction time for customers and reducing development costs. Customers can get gas pipe installed earlier and FEI can reduce installation effort by reducing the duplication of surface infrastructure work. Additionally, FEI expects the program may result in a reduction of installation costs over time. At this time, FEI is not able to estimate the level of savings that may be achieved.

   To date, FEI has completed four party trenching projects in the Fraser Valley, Okanagan and Vancouver Island. The projects have generated many learnings and satisfied customers, as well as provided FEI with opportunities to determine best practices and improve the process.

As part of its continuing efficiency and customer service focus, FEI invests in various information technology opportunities. The following are updates to examples discussed in the 2018 Annual Review, and some new opportunities initiated recently:

- The Planner Tool Box project was implemented in January 2018. The project streamlined and sped up the work order creation process, eliminated repetitive tasks, delivered improvements to user experience/interaction with information systems, and improved customer service. Anticipated labour savings of $0.15 million per year are expected from reduced planner time required to process the different work orders that planners work on (i.e. alterations, install mains, meters, etc.).

- The "Automate Customer Moves" initiative was completed in February 2018. This removes the need for manual intervention in the back end for processing requests and improves turnaround time for customers to complete follow-on activities such as registering for paperless billing, equal payment plan and other Company products and services. At present, the automated completion rate is 66 percent of all online gas moves based on a year-to-date volume of 8,820. The estimated annual savings is $0.2 million starting in 2018.

- FortisBC is redesigning its website (www.fortisbc.com) in order to meets its evolving business needs and the needs and expectations of its customers. Redesigning the website by changing the functionality to be more task oriented will enhance the service provided to customers. Customers and other users (e.g. potential customers, contractors, businesses, media, government, etc.) usually visit the FortisBC website with a specific objective in mind. They seek answers to "How do I… ?" questions. Redesigning the website to be more customer centric with self-service options will make it easier for customers to quickly interact with the Company and find answers to their questions. Additionally, operational efficiencies will result from the use of a new content management technology platform and workflow functionality with content authoring and publishing becoming more streamlined. Estimated annual savings are forecast to be $0.15 million shared between FEI and FBC. The project is currently underway with completion expected in 2019.
- A mobile application to improve ease of access for customers to account information was launched in early 2018. The objective of this customer service focused initiative is to improve ease of access for customers to account information as well as to provide a single point of entry to access current and future products and services. To date, there are 12,000 participants using the tool with a year-end target of 30,000 active users. The application is expected to improve the participation rate in our current online account tool which currently has 388,000 gas customer enrolled, as well as customers' satisfaction in their online experience.

1.4.4 Overview of Capital Expenditures

FEI is projecting that capital expenditures will be above the formula in 2018.

1.4.4.1 Capital Spending Results

FEI's capital spending has been above the formula amount in each year of the PBR term to date, and this trend is expected to continue. Table 1-4 below shows the capital spending from 2014 to 2018.

Table 1-4: Capital Expenditures 2014 to 2018 ($ millions)

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Growth	24.231	21.478	2.753	45.776	28.480	17.296	47.500	33.262	14.238
Other	100.168	98.343	1.825	107.803	110.901	- 3.098	114.641	112.053	2.588
Pension/OPEB	3.915	3.915	-	4.324	4.324	-	4.075	4.075	-
Total	128.314	123.736	4.578	157.903	143.705	14.198	166.216	149.390	16.826
			3.70%			*9.88%*			*11.26%*

	2017			2018			Cumulative		
	Actual	Formula	Variance	Projected	Formula	Variance	Projected	Formula	Variance
Growth	59.542	33.477	26.066	67.912	37.485	30.428	244.962	154.182	90.780
Other	139.416	113.104	26.311	146.260	114.596	31.664	608.287	548.997	59.291
Pension/OPEB	2.663	2.663	-	3.127	3.127	0.000	18.104	18.104	0.000
Total	201.621	149.244	52.377	217.299	155.207	62.092	871.353	721.282	150.071
			35.09%			*40.01%*			*20.81%*

As shown in Table 1-4, Projected 2018 capital expenditures, excluding items forecast outside of the PBR formula, are $62.092 million higher than the formula amount. There are a number of contributing factors which are discussed below.

One set of contributing factors consists of reductions to the capital formula envelope. Specifically, in the Commission's PBR Decision and the subsequent decision that included Vancouver Island and Whistler regions in the PBR Plan, the approved PBR capital formula included the following decreases to the allowed spending as compared to what had been proposed:

1. The sustainment capital for the Vancouver Island region was reduced[7], resulting in an impact of $6.6 million in 2018 and $25.8 million cumulative;
2. The growth factor for service line additions (for the growth capital) and net customer additions (for the other capital) was reduced by one-half,[8] resulting in an impact of $9.9 million in 2018 and $17.7 million cumulative; and
3. The X factor was increased by 0.6 percent (from 0.5 percent to 1.1 percent), resulting in an impact of $0.9 million in 2018 and $4.2 million cumulative.

In addition to the formula-related pressures noted above, FEI has continued to experience other capital cost pressures in 2018 due to work that had been re-prioritized from previous years of the PBR term into 2018 and to manage unforeseen urgent and higher priority activities in 2018.

In response to the capital directives on page 17 of Order G-182-16 and continued by Order G-196-17, capital variances are detailed by year in Appendix C4.

[7] Order G-106-15 in FEI's Application for Approval to Include FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. into the 2014-2019 Multi-Year Performance Based Ratemaking Plan.

[8] In addition, the lag in timing of when customer growth is reflected in the formula as compared to when customers are actually added causes pressure on the formula in years of higher customer growth.

FEI continues to search for capital efficiencies throughout its sustainment and growth programs. As reported in prior Annual Reviews, FEI initiated projects earlier in the planning process in order to better assess and schedule resourcing requirements for design and construction. Projects and programs were prioritized in such a manner to allow for early engineering and design and optimized procurement of equipment and contracting services. FEI continues to streamline and standardize designs and material specifications to reduce costs in inventory, fabrication, and construction. It is FEI's standard practice to combine projects into one construction schedule where possible to reduce shut down and start up operational costs. Further, FEI plans to use the newly installed NPS36 coastal transmission system pipeline and valve stations as isolation and bypass points for projects planned on the adjacent line to realize further capital cost efficiencies.

FEI has been successful in mitigating some of the cost pressures through efficiencies and work prioritization. However, the cost pressures have exceeded the Company's ability to re-prioritize further work within the formula capital spending envelope without incurring more risk to the system. As well, previous work that was delayed is now considered essential or mandatory work and cannot be deferred further. To mitigate this risk exposure, FEI has increased its sustainment activities in 2018. This, combined with growth capital pressures from both higher activity levels and higher cost activities, has resulted in FEI forecasting its capital expenditures to be $62.092 million above the formula for 2018, which is outside of the capital dead band.

1.4.4.2 Treatment of Capital Spending outside of the Dead Band

In the Annual Review for 2017 Rates in Section 1.4.4.2, FEI reviewed the regulatory history for the capital dead band. Based on that regulatory history and as further explored during the review proceeding for that application, the functioning of the approved capital dead band is summarized below.

- The capital dead band places a limit on the extent to which there is earning sharing on variances from (either above or below) the capital formula amount;
- The threshold for the capital dead band is a one year 10 percent variance or a two-year cumulative 15 percent variance from the capital formula amount;
- If the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount;
- The result of exceeding the capital dead band is that there is no earnings sharing for amounts outside of the dead band;
- If the capital dead band is exceeded, FEI will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year.

This treatment was approved by Order G-182-16[9], and in the Annual Review for 2018 Rates, by Order G-196-17, the Commission approved FEI to add the amount of capital in excess of the dead-band to its opening 2018 plant additions balance.

> **The Panel approves FEI's proposal to remove the amount of formula capital which has exceeded the cumulative dead-band from the earnings sharing calculation, and to add the amount of capital in excess of the dead-band to FEI's opening 2018 plant additions balance.**

In the same section, the Panel stated the following regarding rebasing of the capital formula:

> It is clear based on the evidence that FEI expects to exceed the capital dead-band in each of the remaining years of the PBR Plan term and that growth capital in particular will continue to exceed formula amounts. The Panel also notes FEI's response to BCUC IR 6.3 in which FEI confirmed that there is little likelihood that the volume and cost assumptions utilized in developing the PBR Base Capital costs for growth capital will be reflective of actual results during the remainder of the PBR term.[10] Given these circumstances, re-basing formula capital would generally be an appropriate action to take so as to bring the formula spending into better alignment with FEI's actual capital spending needs. Further, it is clear that the Commission in the PBR Decision contemplated re-basing as a potential course of action, as the Commission stated, when considering the cumulative impact of capital spending outside the dead-band: "The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula."[11]
>
> However, the Panel acknowledges that the PBR Plan term is nearing the end and that any changes at this time to base capital resulting from re-basing would not take effect until the final year of the PBR Plan term. Thus, the Panel does not consider it appropriate to impose the additional regulatory process and costs which would be required for a re-basing hearing given the limited time remaining in the current PBR Plan term. While the Panel does consider there to be some merit to including the capital spending in excess of the dead-band as part of the 50/50 earnings sharing mechanism, as this would potentially serve to better maintain the incentive properties of the PBR Plan, the Panel acknowledges FEI's statement that this would result in a change to the overall PBR Plan design and that such a change is not within the scope of this annual review.

[9] G-182-16, page 16.
[10] Exhibit B-3, BCUC IR 6.3.
[11] Exhibit B-3, BCUC IR 10.7, Attachment 10.7.

FEI agrees that re-basing of capital expenditures should not be undertaken during the remainder of the current PBR term. While FEI is continuing to experience capital cost pressures, the dead band mechanism remains a reasonable way to deal with capital cost pressures by ensuring no sharing of negative earnings impacts with customers for capital expenditures in excess of 10 percent of the formula amount or 15 percent over two years.

To calculate the 2018 dead band adjustment, FEI notes that its actual 2017 capital exceeded the formula by approximately 9.88 percent, after the 2017 dead band adjustment. FEI is further projecting to exceed the 2018 formula by 40.01 percent as shown in Table 1-4 and discussed further in Appendix C-4. Therefore, the cumulative amount over the capital formula for calculating the two-year dead band adjustment is 49.89[12] percent. FEI must exclude from the Earnings Sharing calculation the greater of:

- The one-year capital dead band difference between the projected capital spending overage of 40.01 percent and the one year dead band limit of 10 percent, for a net adjustment of 30.01 percent; or
- The two-year capital dead band difference between the cumulative projected capital spending overage of 49.89 percent and the two year cumulative dead band limit of 15 percent, for a net adjustment of 34.89 percent.

Accordingly, FEI added 34.89 percent of its 2018 capital, or $54.145 million[13] to its opening plant in service for 2019 so that the two-year cumulative capital variance is within the two-year dead band at 15 percent. FEI also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($54.145 million), such that the earnings sharing with customers is increased (see Section 10 of the Application). In this way, there is no earnings sharing on the amount by which FEI exceeded the dead band.

FEI has also included a true-up to the 2017 dead band adjustment in this Application. In FEI's Annual Review for 2018 Rates FEI had projected a 2017 dead band adjustment of $26.473 million that was added to 2018 opening plant balance for rate making purposes. The actual 2017 dead band adjustment is $37.632[14] million due to additional growth capital pressures even beyond what was forecast. Consequently, FEI has increased the 2018 opening balance plant for this Application by the actual 2017 dead band adjustment of $37.632 million. Both the 2017 Actual and the 2018 Projected dead band adjustments are included in rate base in calculating 2019 rates.

[12] 9.88 percent plus 40.01 percent

[13] $217.301 million actual spending less $54.145 million = $163.156 million revised spending. When compared to $155.209 million approved formula this results in a revised capital spending variance of 5.12% over one year and 15% over two years.

[14] Section 10, Table 10-2, Line 33

1.4.4.3 Conclusion on Capital Spending

While FEI is continuing to experience capital cost pressures, the capital spending is required to add customers and limit increasing risk exposure in the system, and avoid unplanned and urgent capital work that reduces productivity and drives up project costs by reducing FEI's ability to plan and execute the work.

1.4.5 Summary

In summary, FEI's experience in 2014 through 2019 has resulted in the realization of earnings sharing on O&M, with no increases in delivery rates for three of the six years, and increases that are in line with inflation for the remaining three years. The experience during the PBR Plan has also shown the challenges of the capital formula.

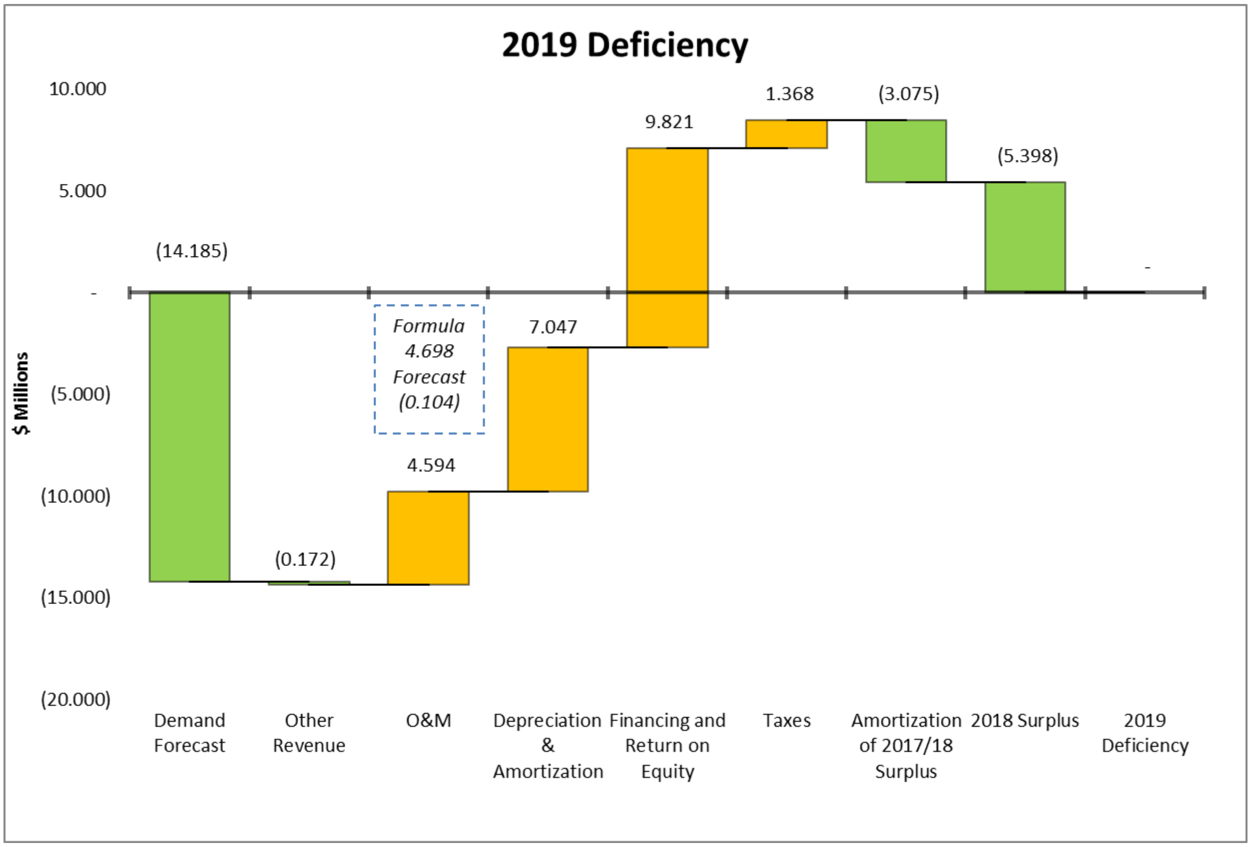
1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2019

The proposed delivery rates for 2019 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 0.5 percent increase from 2018 delivery rates; however, FEI is proposing to maintain 2019 delivery rates at existing levels[15] by amortizing a portion of the 2017 & 2018 Revenue Surplus account equal to the 2019 revenue deficiency.

The following chart summarizes the items that contribute to the 2019 deficiency including the proposed amortization of the 2017 & 2018 Revenue Surplus account so that delivery rates are maintained at existing levels. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The total is then the sum of all of the previous bars, and is shown at the end of the chart as zero.

[15] After implementation of approved (G-135-18) rate design changes

Figure 1-1: 2019 Delivery Revenue Deficiency ($ millions)[16]



Each of the categories is discussed briefly below.

1.5.1 Demand Forecast (Section 3)

In 2019, demand is forecast to increase by 7.2 PJs from 2018 Approved, with the main increases being 6.3 PJs for industrial demand, 0.8 PJs for Natural Gas for Transportation (NGT) and 0.6 PJs for commercial demand, partially offset by a decrease in residential demand of 0.5 PJs and. Based on the existing rates for each rate schedule, FEI's 2019 revenue forecast at existing rates is $1,205.500 million and 2019 gross margin forecast is $836.218 million.

1.5.2 Other Revenue (Section 5)

Other revenue is forecast to reduce the 2019 deficiency by approximately $0.2 million, mainly due to an increase in SCP Third Party Revenue and NGT Tanker Rental Revenue.

[16] Due to its relative size, the impact of increasing formula capital of approximately $0.239 million has not been isolated and is embedded within all capital-related revenue requirement categories.

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

FEI establishes the bulk of its O&M costs by formula during the PBR term. For 2019, the formula incorporates an inflation factor (I Factor) of 2.505 percent, a productivity improvement factor (X Factor) of 1.1 percent and a customer growth factor of 0.776 percent for a total increase in formula O&M of 2.192 percent. O&M forecast outside of the formula is increasing by 0.5 percent over 2018 approved, primarily due to the exogenous factors related to the Employer Health Tax (EHT) net of MSP premium reductions, and increases in Rate Schedule 46 O&M, partially offset by decreases in pension and OPEB. The increase in total O&M expense net of capitalized overhead is $4.594 million.

1.5.4 Depreciation and Amortization (Section 7 and Section 12)

The increase in depreciation expense is primarily the result of the depreciation on the first phase of the Lower Mainland Intermediate Pipeline System Upgrade (LMIPSU) Project commencing on January 1, 2019. This was partially offset by a decrease in deferral amortization expense of $4.6 million. This is due to a number of factors, including a $13.4 million increased credit amortization of the Flow-through Variance Account, partially offset by a higher balance in the Energy Efficiency and Conservation incentives deferral, the elimination of the amortization of the Customer Service Variance account and an increase in the amortization of the BCUC Levies Variance deferral.

1.5.5 Financing and Return on Equity (Section 8)

FEI has forecast a mid-year long-term debt issue for 2019 of $150 million and is forecasting a short-term debt rate for 2019 of 3.10 percent, an increase from the 2.10 percent short term debt rate embedded in the 2018 Approved revenue requirement. Overall, interest expense is forecast to increase from 2018 by $6.102 million on a higher overall rate base.

Increases in rate base predominantly from the first phase of the LMIPSU Project have increased FEI's equity return by $3.719 million. FEI has utilized the approved 2019 capital structure and return on equity of 38.5 percent at 8.75 percent respectively.

1.5.6 Taxes (Section 9)

Property taxes are forecast to increase by 0.6 percent or $0.402 million from 2018 Approved 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 2018. Taxes are forecast to increase in 2019 by $0.966 million primarily due to a higher delivery margin in 2019 offset by increase in O&M and interest expense.

1.5.7 Service Quality Indicators

FEI's 2017 and June 2018 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2017, for those SQIs with benchmarks, all nine performed at or better than the approved benchmarks. In 2018 April year to date, eight performed better than the approved benchmarks with one performing better than the threshold and within the performance range. 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.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2019 O&M and Capital formula amounts according to the PBR formula.

In the PBR Decision and Commission Order G-162-14, the Commission approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting, and the following growth factors:

- For growth capital, the growth factor is 50 percent of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as [1 + $((SLA_{t-1}-SLA_{t-2})/SLA_{t-2})$ x 50%)].
- For all other cases, the growth factor is 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as [1 + $((AC_{t-1}-AC_{t-2})/ AC_{t-2})$ x 50%)].

Further guidance on how to calculate the Inflation and Growth factors was provided in Commission Order G-164-14, which states:

4. FortisBC Energy Inc. is approved to use inflation data from the most recent 12 month period (July through June) for the 2014 rate change calculations and the future annual reviews.
5. FortisBC Energy Inc. is approved to use Statistics Canada CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC.

The Inflation Factor and Growth Factor calculations utilize these inputs, but as applied to 2019. FEI has used July 2017 through June 2018 inflation data for the 2019 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

As discussed below, the 2019 inflation factor based on prior year's BC-CPI and BC-AWE is 2.505 percent, and the SLA and AC Growth Factors are 5.600 percent and 0.776 percent, respectively.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the PBR Decision, the Commission approved an inflation factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting. Consistent with Commission Order G-164-14 regarding FEI's PBR Compliance Filing, FEI uses inflation data from July through June and CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC. The supporting Statistics Canada CANSIM Tables 326-0020 and 281-0063 are provided in Appendix A1. The latest available month of May 2018 has been used as a placeholder for June 2018 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.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing CPI-BC of 2.345 percent and AWE-BC of 2.635 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (2.345 percent x 45 percent) + (2.635 percent x 55 percent) = 2.505 percent.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020 2002 = 100	*CANSIM 281-0063*	12 Mth Average		Year over year % change			
Date	BC CPI index	BC AWE $	CPI index	AWE $	CPI %	AWE %	I Factor %	PBR Year
Jul-2016	123.3	916.30						
Aug-2016	123.4	922.72						
Sep-2016	123.2	919.27						
Oct-2016	123.1	918.42						
Nov-2016	122.7	927.27						
Dec-2016	122.7	931.13						
Jan-2017	123.5	930.35						
Feb-2017	123.6	930.17						
Mar-2017	124.2	934.96						
Apr-2017	124.4	936.88						
May-2017	125.0	940.14						
Jun-2017	125.2	944.40	123.7	929.33				
Jul-2017	125.6	937.98						
Aug-2017	125.9	941.65						
Sep-2017	125.7	952.43						
Oct-2017	125.6	952.38						
Nov-2017	125.9	952.81						
Dec-2017	125.2	957.62						
Jan-2018	126.1	956.68						
Feb-2018	127.0	958.80						
Mar-2018	127.4	963.03						
Apr-2018	127.7	952.75						
May-2018	128.4	959.86						
Jun-2018	128.6	959.86	126.6	953.82	2.345%	2.635%	2.505%	2019

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the Commission approved the use of the following growth terms for FEI:

- For growth capital, the growth factor is 50 percent of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as $[1 + ((SLA_{t-1} - SLA_{t-2})/SLA_{t-2}) \times 50\%)]$.
- For all other cases, the growth factor is 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as $[1 + ((AC_{t-1} - AC_{t-2})/ AC_{t-2}) \times 50\%)]$.

1 The calculations for the Average Customer and Service Line Additions growth factors are
2 provided in Tables 2-2 and 2-3 below.

3 **Table 2-2: Average Customer (AC) Growth Factor Calculation**

	Total Average Customers	12 Month Avg Customers	AC Factor @ 50%	PBR Year
Jul-16	981,766			
Aug-16	982,078			
Sep-16	983,343			
Oct-16	985,701			
Nov-16	988,462			
Dec-16	991,573			
Jan-17	993,397			
Feb-17	994,305			
Mar-17	995,136			
Apr-17	995,859			
May-17	996,713			
Jun-17	996,691	990,419		
Jul-17	995,664			
Aug-17	995,681			
Sep-17	996,444			
Oct-17	999,343			
Nov-17	1,003,259			
Dec-17	1,006,012			
Jan-18	1,009,132			
Feb-18	1,010,586			
Mar-18	1,012,016			
Apr-18	1,013,040			
May-18	1,013,781			
Jun-18	1,014,422	1,005,782	0.776%	2019

4

Table 2-3: Service Line Additions (SLA) Growth Factor Calculation

	Total Service Line Additions	12 Month Sum	SLA Factor @ 50%	PBR Year
Jul-16	717			
Aug-16	896			
Sep-16	985			
Oct-16	1,410			
Nov-16	1,707			
Dec-16	1,552			
Jan-17	1,407			
Feb-17	1,153			
Mar-17	1,584			
Apr-17	983			
May-17	1,188			
Jun-17	1,301	14,883		
Jul-17	938			
Aug-17	1,313			
Sep-17	1,191			
Oct-17	1,440			
Nov-17	1,657			
Dec-17	1,705			
Jan-18	1,165			
Feb-18	1,502			
Mar-18	1,603			
Apr-18	1,196			
May-18	1,541			
Jun-18	1,299	16,550	5.600%	2019

2.4 INFLATION AND GROWTH CALCULATION SUMMARY

Using the I-Factor and Growth Factors as calculated above, and the approved X-Factor of 1.1 percent, a summary of the factors used in the PBR formula for 2019 is provided in Table 2-4.

Table 2-4: Summary of Formula Drivers

	2019
Cost Drivers	
Service Line Additions Factor @ 50%	5.600%
Customer Growth Factor @ 50%	0.776%
Escalators	
CPI	2.345%
AWE	2.635%
Non Labour	45%
Labour	55%
CPI/AWE Inflation	2.505%
Productivity Factor	-1.100%
Net Inflation Factor	1.405%

In summary, the formula factor for O&M and for sustainment and other capital for 2019 is 102.192 percent, calculated as (1 + 0.776 percent) x (1 + 1.405 percent).

The formula factor for growth capital for 2019 is 107.084 percent, or (1 + 5.600 percent) x (1 + 1.405 percent).

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 based on the forecast total energy demand from residential, commercial and industrial customers in 2019, as well as the revenue and margin using 2019 volumes at 2018 delivery rates and applicable 2018 commodity, storage and transport rates.[17] As described in detail below, FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years, and provides a reasonable estimate of future natural gas demand for 2019. FEI is forecasting an increase in consumption in 2019 compared to 2018 Approved demand. The total normalized demand is forecast to be approximately 235.4 PJs in 2019. The forecast for 2019 is up 7.2 PJs from 2018 Approved, with increases of 6.26 PJs for industrial demand, 0.78 PJs for Natural Gas for Transportation (NGT) and 0.61 PJs for commercial demand, partially offset by a decrease in residential demand of 0.45 PJs. Based on the 2018 rates for each customer class, FEI's 2019 revenue forecast is $1,205.500 million and FEI's 2019 gross margin forecast is $836.218 million. FEI has provided extensive supplementary information on its demand forecast in Appendix A of the Application.

The remainder of this section is organized as follows:

- Section 3.2 – Overview of Forecast Methods
- Section 3.3 – Use per Customer Forecast
- Section 3.4 – Net Customer Additions Forecast
- Section 3.5 – Total Demand Forecast
- Section 3.6 – Revenue and Margin Forecast
- Section 3.7 – Summary

In addition to the sections described above, FEI has included the following appendices related to the demand forecast:

- Appendix A1 – Conference Board of Canada Report

  Provides the data and source for the BC Housing Starts that are utilized in FEI's residential demand forecast.

- Appendix A2 – Historical Forecast and Consolidated Tables

[17] Order G-173-17 for the cost of gas and storage and transport rates effective January 1, 2018, Order G-196-17 for permanent delivery rates effective January 1, 2018, and Order G-112-18 for the propane commodity rates effective July 1, 2018. The delivery rates do not include the applicable delivery rate riders, which are set separately from the delivery rates; however, the delivery rate riders were approved by the same Order G-196-17.

Provides historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals, including variances and the results of the Industrial Survey. Based on the 10 years of data shown in Section 3.4 of Appendix A2, the 10-year mean average percentage error of the aggregate demand forecast is 3.4 percent, which includes a residential demand forecast error of 2.4 percent and a commercial demand forecast error of 2.5 percent. Most recently, the aggregate demand forecast error for 2017 was 4.7 percent which includes a residential demand forecast error of 4.2 percent and a commercial demand forecast error of 3.4 percent. Section 3.20 of Appendix A2 includes a comparison of the ETS forecasting results to the current forecasting methods for residential and commercial UPC and commercial customer additions for 2012 through 2017.

- Appendix A3 – Demand Forecast Methods

Provides a detailed description of FEI's demand forecast methods, including an explanation of the Industrial Survey. FEI's forecast methods are consistent with those used in previous applications.

3.2 OVERVIEW OF FORECAST METHODS

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

- Net customer additions forecast;[18]
- Average use per customer (UPC) forecast; and
- Industrial Forecast.

The demand forecast for residential and commercial customers is based upon forecasts for number of customers and UPC rates, consistent with the past methods. Specifically, the average UPC is estimated for customers served under Rate Schedules 1, 2, 3 and 23 and is 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.

The forecast of industrial energy demand is based upon customer-specific forecasts obtained through an Industrial Survey as discussed in Section 3.5.3.

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

The forecast NGT Demand is for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) volumes. The method used to complete the NGT demand forecast is discussed in Appendix B.

[18] The net customer additions are the year-over-year change in the total number of customers.

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:

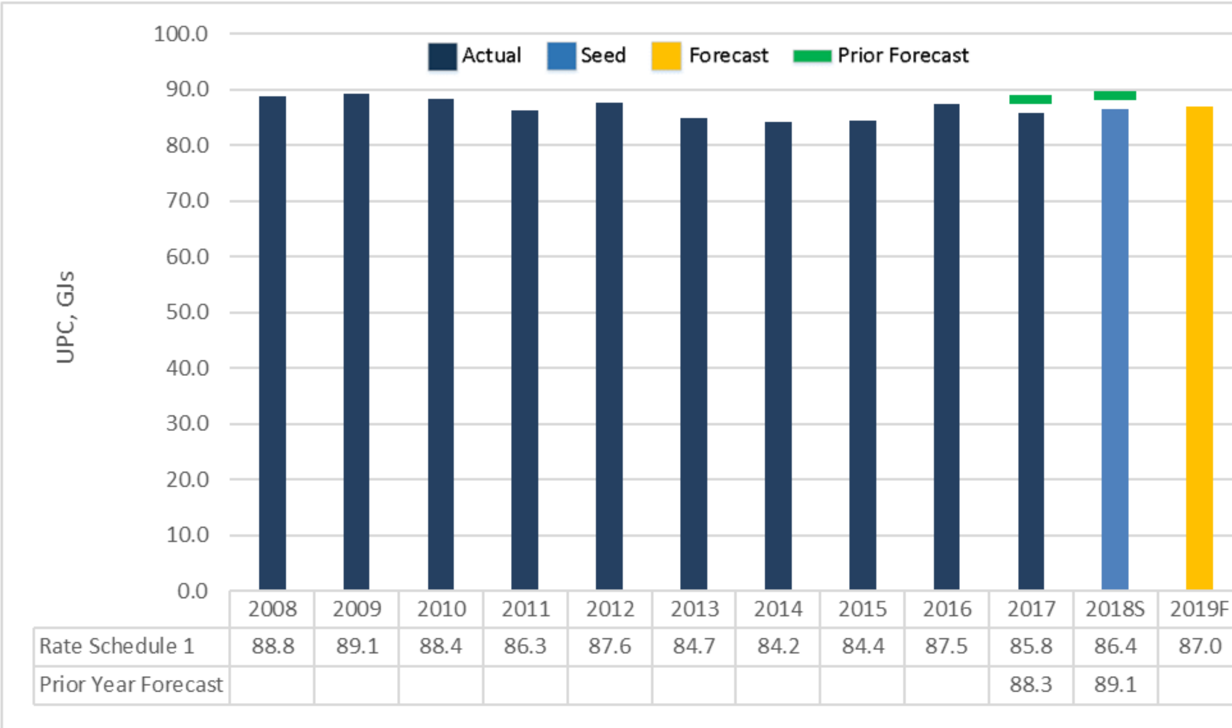
- Actual Years: Actual years are those for which actual data exists for the full calendar year. The 2019 Annual Review is based on actual data up to and including 2017, the latest calendar year for which full actual data exists.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2018 and the Seed Year forecast is based on the latest actual years, including 2017. As such, the 2018 Seed Year forecast in this Application will differ from the 2018 Forecast presented in the Annual Review for 2018 Delivery Rates, for which 2017 actual data was not available.
- 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.

3.3 *RESIDENTIAL AND COMMERCIAL USE PER CUSTOMER FORECAST*

Individual UPC projections for each residential and commercial rate schedule are developed by considering the recent (three-year) historical weather-normalized UPC. The analysis of historical normalized residential use rates indicates an inclining trend for the residential and commercial rate schedules.

As shown in Figure 3-1, the Residential (Rate Schedule 1) UPC is forecast to increase by approximately 0.6 GJs (0.7 percent) in 2019.

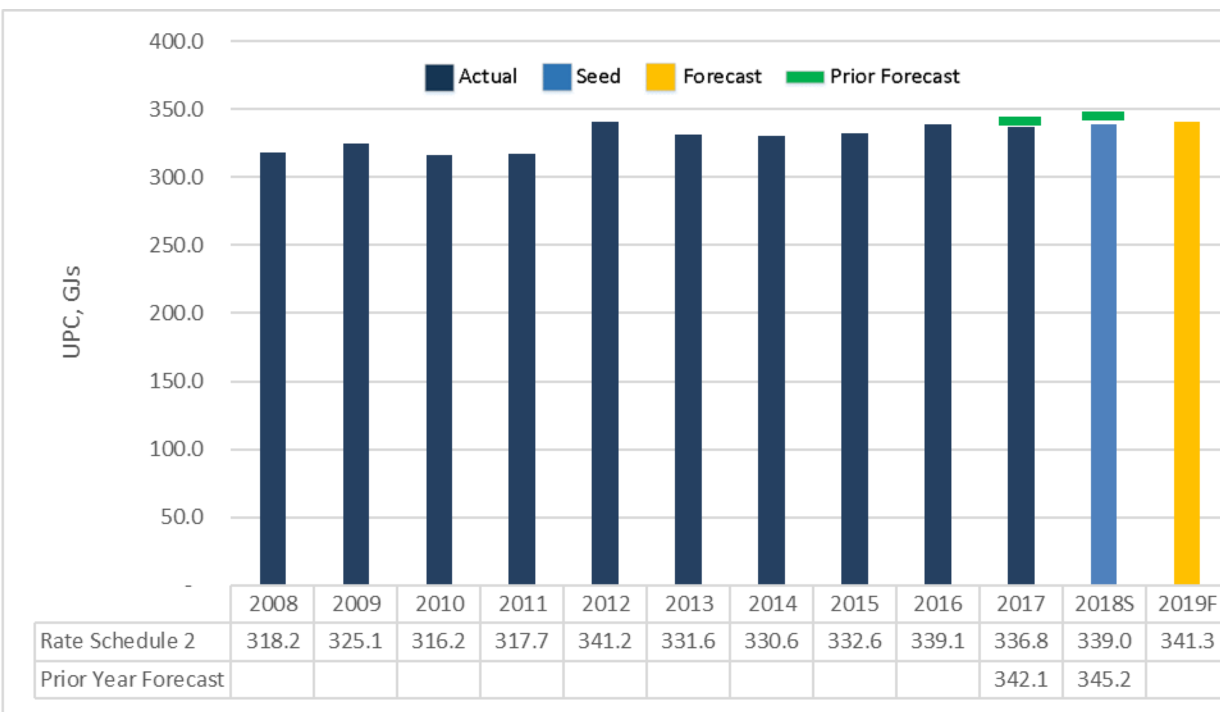
Figure 3-1: Rate Schedule 1 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 1	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	86.4	87.0
Prior Year Forecast										88.3	89.1	

As shown in Figure 3-2, the Small Commercial (Rate Schedule 2) UPC is forecast to increase by 2.3 GJs (0.7 percent) in 2019.

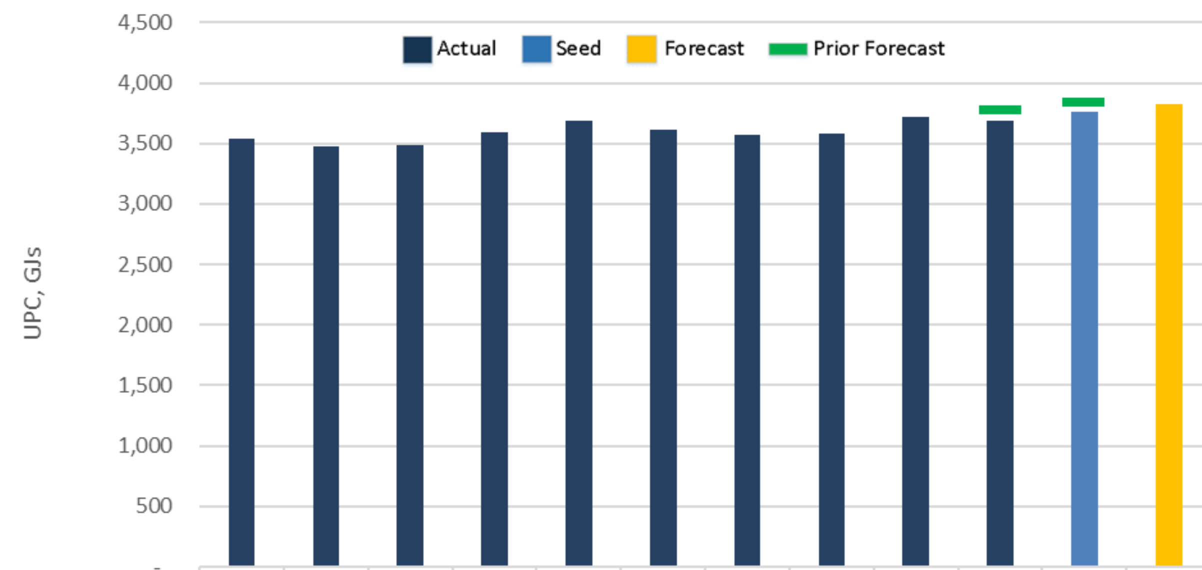
Figure 3-2: Rate Schedule 2 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 2	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	339.0	341.3
Prior Year Forecast										342.1	345.2	

As shown in Figure 3-3, the Large Commercial (Rate Schedule 3) UPC is forecast to increase by 68 GJs (1.8 percent) in 2019.

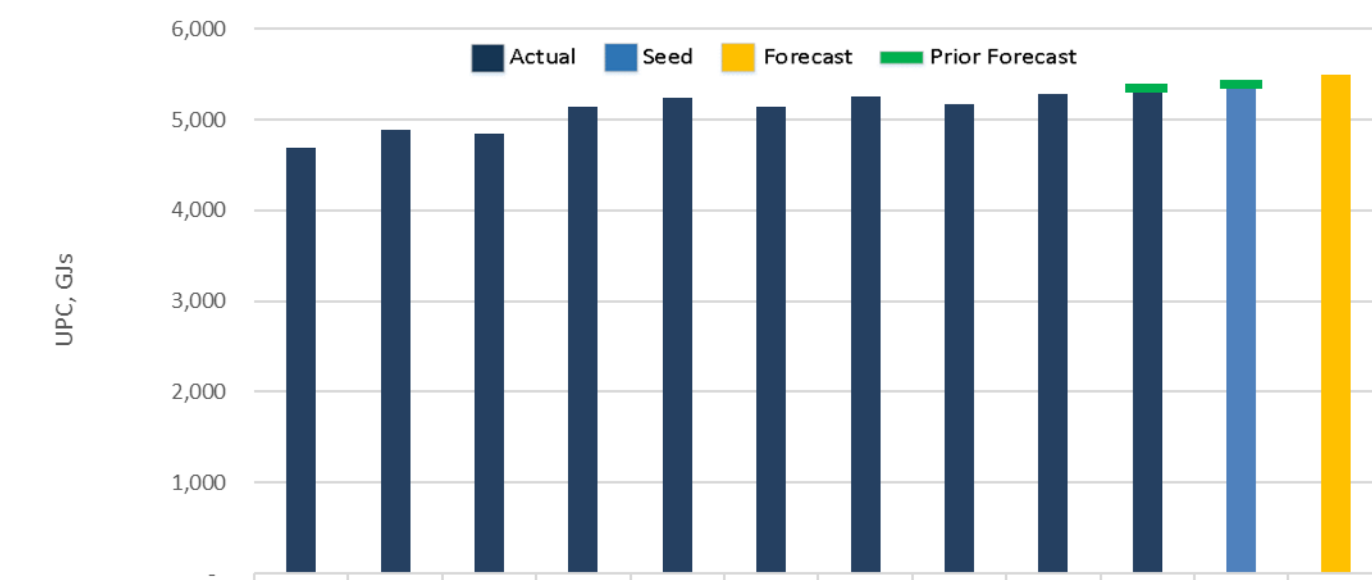
Figure 3-3: Rate Schedule 3 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 3	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,763	3,831
Prior Year Forecast										3,781	3,842	

As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to increase by 56.4 GJs (1.0 percent) in 2019.

Figure 3-4: Rate Schedule 23 UPC



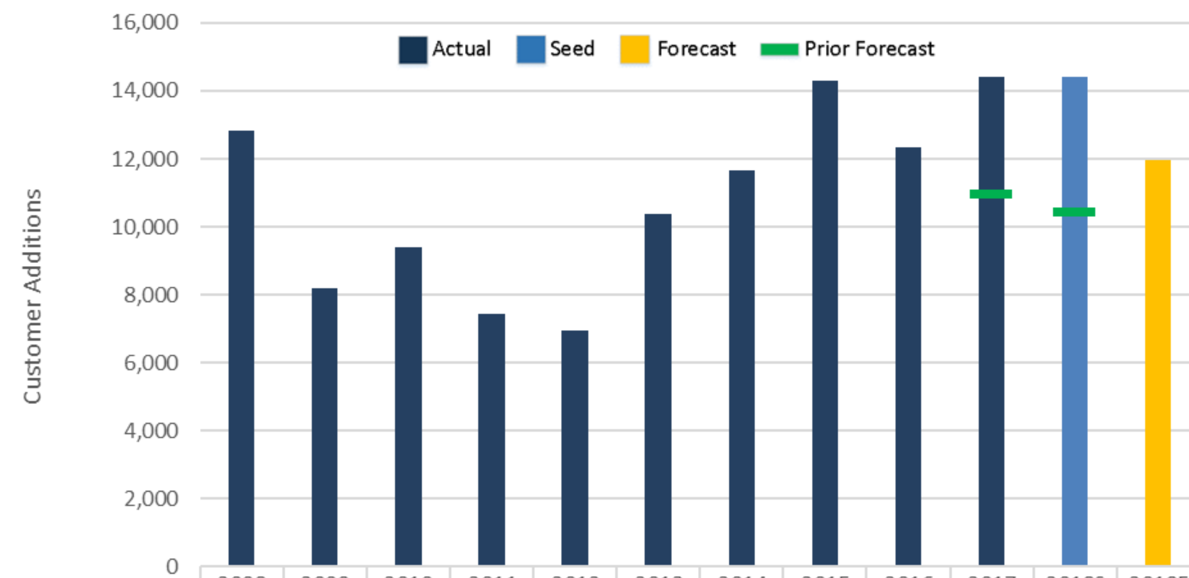
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 23	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,435	5,492
Prior Year Forecast										5,353	5,399	

3.4 *RESIDENTIAL AND COMMERCIAL NET CUSTOMER ADDITIONS FORECAST*

The forecast of net customer additions is the next component in determining the total energy demand for residential and commercial customers.

As shown in Figure 3-5, the rate of growth seen in FEI's customer base (residential, commercial and industrial) reached roughly 12,800 net customer additions in 2008, then declined to below 10,000 annual net customer additions for the period from 2009 through 2012. Net customer additions have been stronger since 2013 with the largest increase occurring in 2017. The Company is forecasting net customer additions at 14,417 in 2018 and 11,946 in 2019.

Figure 3-5: Total Net Customer Additions

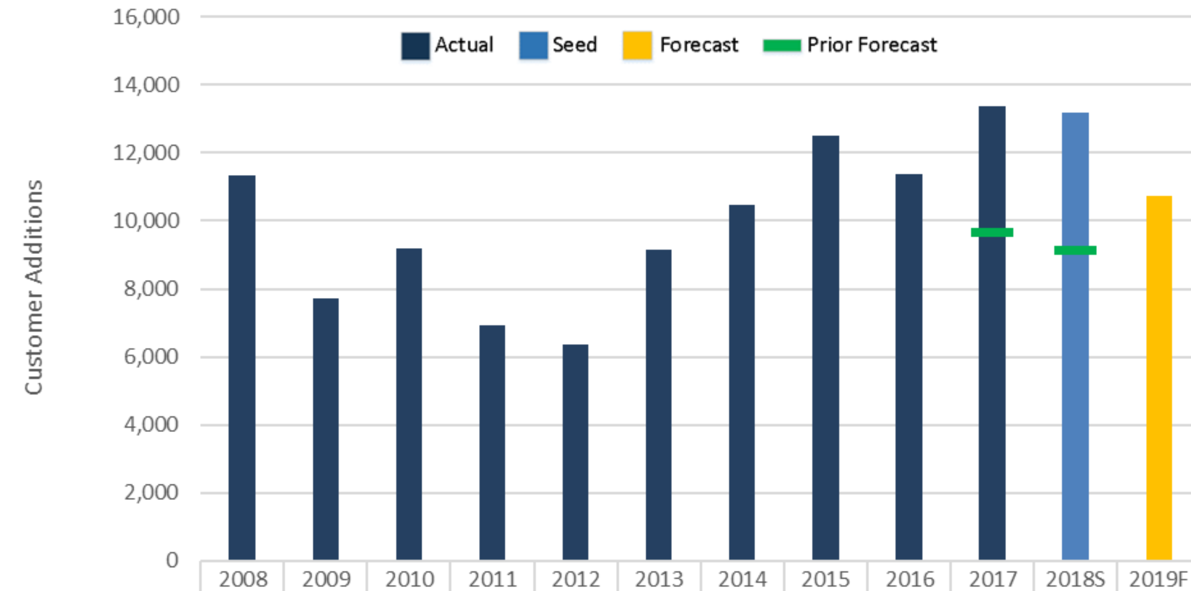


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Total	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	12,324	14,417	14,417	11,946
Prior Year Forecast										10,986	10,435	

The Conference Board of Canada (CBOC) housing starts forecast found in Appendix A1 provides a proxy for residential net customer additions. 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., 2015 to 2017).

Figure 3-6 provides the residential net customer additions for 2008 through 2019.

Figure 3-6: Residential Net Customer Additions

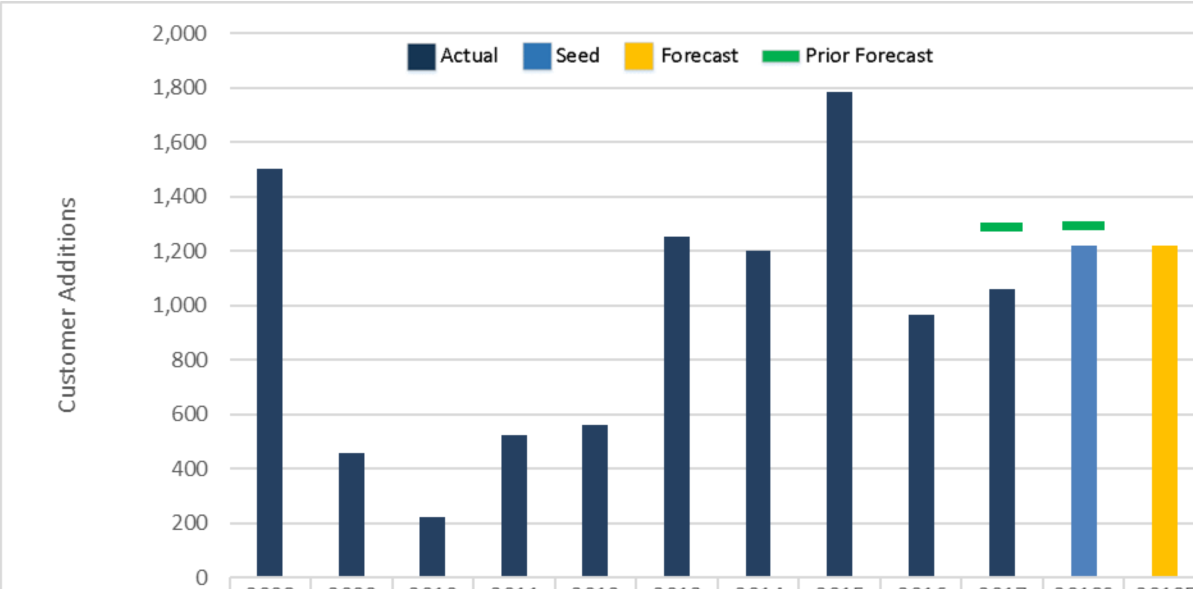


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 1	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	13,195	10,724
Prior Year Forecast										9,696	9,141	

As shown in the preceding figure, residential net customer additions started to recover in 2013. The 2019 Forecast of 10,724 additions reflects a lower CBOC housing starts forecast for BC than experienced in 2017 or projected for 2018.

Figure 3-7 provides the commercial net customer additions for 2008 through 2019.

Figure 3-7: Commercial Net Customers Additions



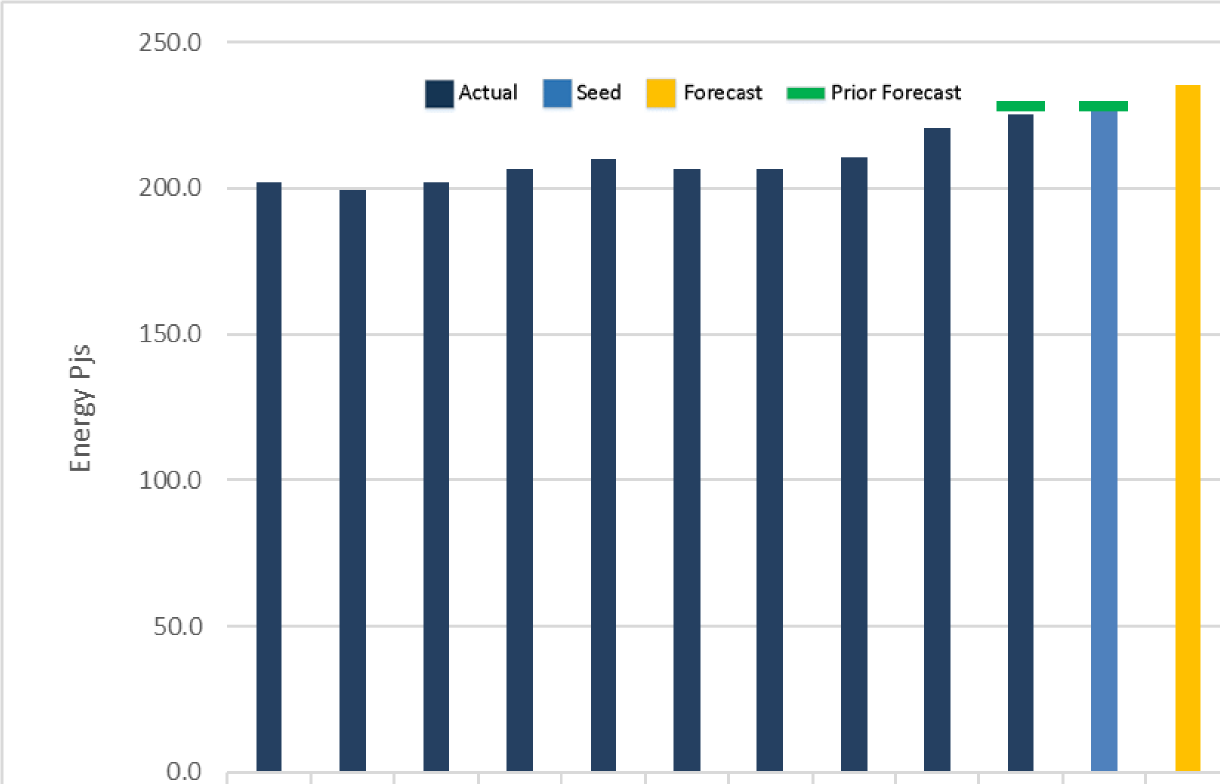
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Commercial	1,504	456	223	522	561	1,252	1,201	1,785	965	1,060	1,222	1,222
Prior Year Forecast										1,290	1,294	

As shown above, the Company is forecasting 1,222 commercial net customer additions for 2019 based on three years of history (2015 to 2017).

3.5 *DEMAND FORECAST*

FEI's total energy demand consists of the residential and commercial normalized demand and the industrial and NGT demand. As seen below in Figure 3-8, the total energy demand is projected to be approximately 229.0 and 235.4 PJs, respectively, in 2018 and 2019.

Figure 3-8: Total Energy Demand in PJs



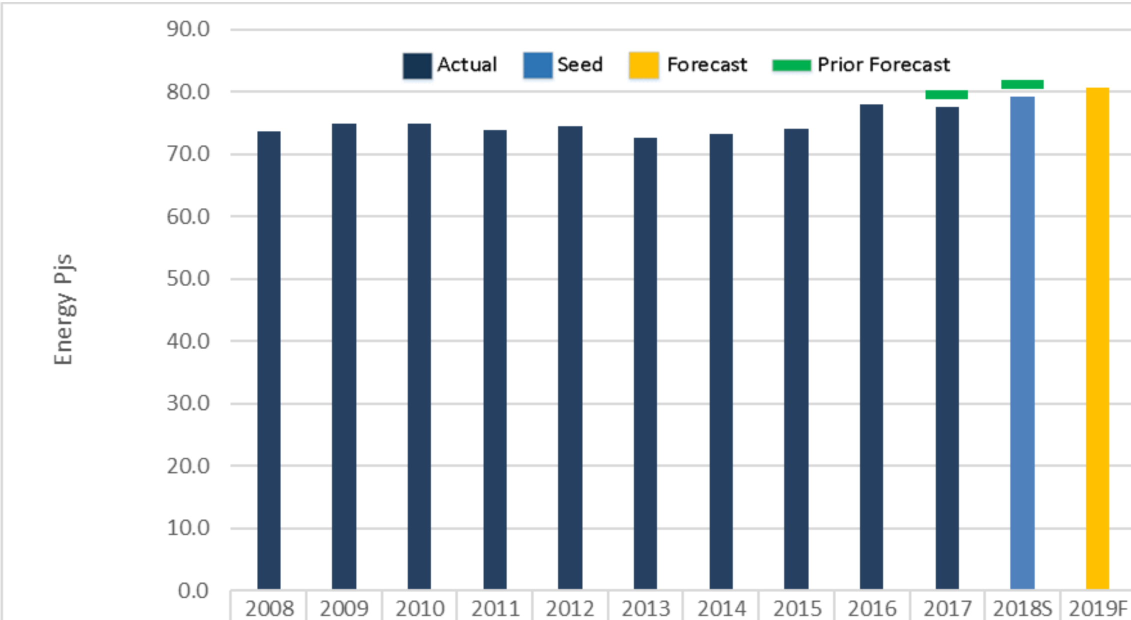
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Total Demand	202.1	199.2	201.9	206.7	209.9	206.6	206.5	210.6	220.6	225.0	229.0	235.4
2018F PBR										228.0	228.2	

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

3.5.1 Residential Demand

As shown below in Figure 3-9, the impact of the forecast 2019 residential use rate coupled with the net customer additions forecast results in an increased residential normalized energy demand forecast compared to 2017. This increase is consistent with the growth observed since 2013.

Figure 3-9: Normalized Residential Demand

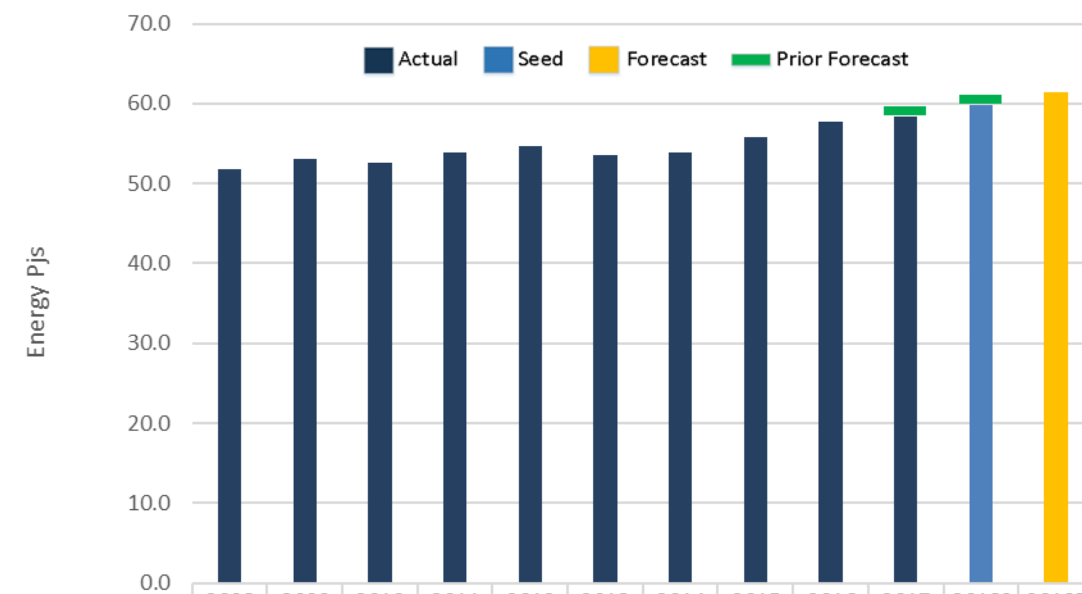


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 1	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5	79.2	80.8
Prior Year Forecast										79.7	81.2	

3.5.2 Commercial Demand

As seen in Figure 3-10 below, demand in the commercial rate schedules is also forecast to grow in 2019 compared to 2017.

Figure 3-10: Commercial Demand



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Commercial	51.8	53.0	52.5	54.0	54.7	53.5	53.9	55.7	57.7	58.3	59.8	61.3
Prior Year Forecast										59.2	60.7	

3.5.3 Industrial Demand

The demand for the majority of industrial customers is forecast using the Industrial Survey.

FEI's survey method is consistent with prior years and continues to include the improvements to the method resulting from FEI's review of its Demand Forecast Method for Rate Schedule 22, as reported in Appendix A4 of FEI's Annual Review for 2016 Rates Application.[19]

For the 2019 Forecast, customers completed the survey in June of 2018. 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 complete by July 4, 2018 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 May 25, 2018.

As shown in Table 3-1 below, the response rate achieved in 2018 was 49 percent of industrial customers, representing approximately 89 percent of industrial volumes. Of the remaining

[19] Appendix A4 of FEI's Annual Review for 2016 Delivery Rates Application is available online at: http://www.bcuc.com/Documents/Proceedings/2015/DOC_44495_B-2_FEI_Annual-Review-2016-Rates-Application.pdf.

industrial customers, 44 percent received the survey and three reminder notifications but did not reply. This group represents 9 percent of the industrial demand. Surveys could not be delivered to 7 percent of the industrial customers due to issues such as incorrect email addresses. This group represents 1 percent of the total industrial load.

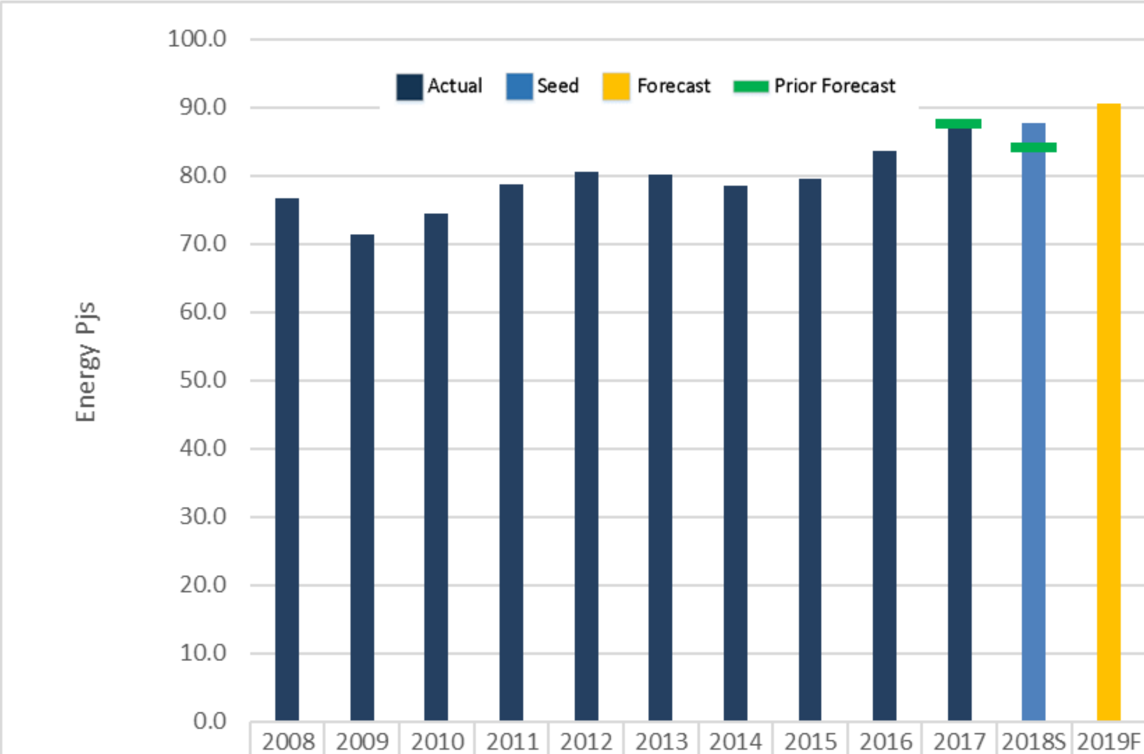
Table 3-1: Industrial Survey Response Rates

2018 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	49.35%	89.39%
Survey delivered but not completed	The survey was delivered , but after three follow-up emails was not completed.	43.86%	9.44%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	6.79%	1.17%
Total		100.00%	100.00%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 10 percent of the total industrial demand) was set to 2017 actual consumption.

As seen in Figure 3-11 below, the demand from the industrial rate schedules is forecast to be 90.6 PJs in 2019.

Figure 3-11: Industrial Demand[20]



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Industrial	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	87.7	90.6
Prior Year Forecast										87.7	84.3	

The Industrial demand in the figure above includes demand under Rate Schedule 22. The 2019 forecast Rate Schedule 22 demand is 43.2 PJs, up approximately 4.9 PJs from the 2018 Approved demand.

3.5.4 Natural Gas for Transportation and LNG Demand

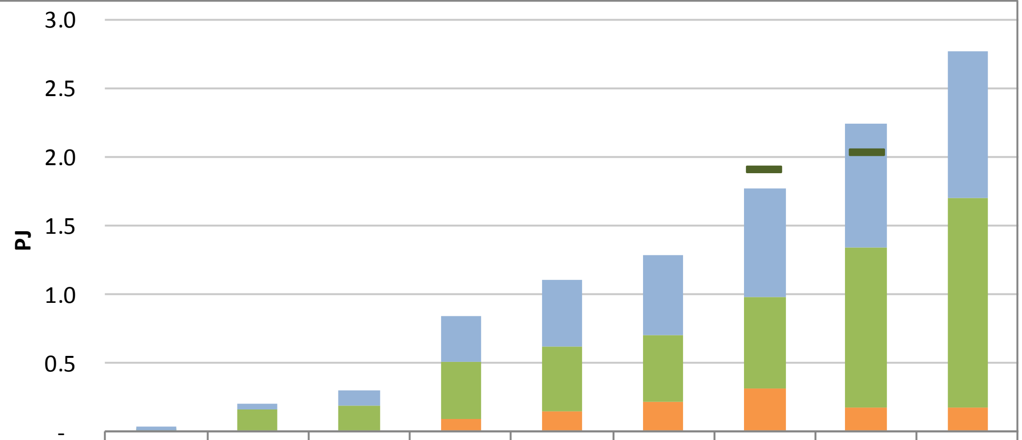
This section summarizes the CNG and LNG demand forecasts related to demand derived from GGRR incentives awarded, FEI's General Terms and Conditions 12B and non-incentive related demand for CNG and LNG supplied under Rate Schedule 46. The details of incentives and fuelling stations driving the NGT portion of this demand can be found in Appendix B1.

The following figure shows the 2011 to 2017 Actual, 2017 and 2018 Approved, 2018 Projected, and 2019 Forecast annual demand for CNG for Rates Schedules 3, 5, 23 and 25 (RS 3/5/23/25) and LNG for Rate Schedule 46 (RS 46).[21]

[20] Excludes Burrard Thermal and NGT.

[21] Rate Schedule 16 expired on December 31, 2014. Effective January 1, 2015, all LNG customers receive service under Rate Schedule 46.

Figure 3-12: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[22]



	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018P	2019F
RS 3/5/23/25 - CNG (NGT)	0.0	0.1	0.1	0.3	0.5	0.6	0.8	0.9	1.1
RS 46 - LNG (NGT)	0.0	0.2	0.2	0.4	0.5	0.5	0.7	1.2	1.5
RS 46 - LNG (Other)	-	-	-	0.1	0.1	0.2	0.3	0.2	0.2
Total CNG & LNG	0.0	0.2	0.3	0.8	1.1	1.3	1.8	2.2	2.8
Prior Year Forecast							1.9	2.0	

The currently projected 2018 demand is 0.2 PJs higher than the prior year Forecast 2018 demand, which is primarily due to the timing of the in-service dates and higher than expected volume consumption from British Columbia Ferry Services Inc. (BC Ferries) and Seaspan Ferries Corp. (Seaspan). In addition, the increased LNG demand from Potelco, which is a utilities services company located in Kent, Washington and operates a number of LNG trucks, contributed to the variance.

The CNG-NGT demand is forecasted to increase by approximately 0.2 PJs in 2019 from the 2018 Projected level. This is primarily attributable to incremental load from existing customers including TransLink adding new natural gas buses, and Waste Management adding additional waste haulers. Although FEI expects the addition of two new CNG stations in 2019, full CNG volumes from those stations are not expected to be attained until 2020.

The LNG-NGT demand is forecasted to increase by approximately 0.3 PJs in 2019 from the 2018 Projected level. This is primarily attributable to the updated volumes mentioned above relating to BC Ferries, Seaspan, and Potelco.

The forecast in demand for LNG-Other includes LNG used for non-NGT activities primarily related to the use of LNG for power generation in northern Canada and other non-NGT (i.e. non-transportation related) market segments. These customers are currently taking LNG on a spot basis (i.e. with no contract demand). In 2018, FEI expects to deliver approximately 0.2 PJs

[22] 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.

to these types of customers, and expects the RS 46-Other types of customers to maintain their consumption at that level for 2019.

3.6 REVENUE AND MARGIN FORECAST

The forecast of revenues and margins has been developed by considering the total 2019 energy forecast applied at 2018 delivery rates and applicable 2018 commodity and storage and transport rates.

3.6.1 Revenue

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

Table 3-2 below summarizes the approved, projected and forecast revenue for 2018 and 2019.

Table 3-2: Forecast Sales Revenue at Approved Rates

Revenue ($ millions)	Approved 2018	Projected 2018	Forecast 2019
Residential [1]	739.42	691.686	702.589
Commercial [2]	391.286	367.382	374.745
Industrial [3]	115.602	121.418	128.166
Total	**1,246.308**	**1,180.486**	**1,205.500**

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

3.6.2 Margin

Margins are calculated by subtracting the cost of gas (discussed in Section 4) from the total revenues set out in Table 3-2 above.

Table 3-3 below summarizes the approved, projected and forecast margin for 2018 and 2019, by customer segment, at 2018 delivery rates.

Table 3-3: Forecast Gross Margin at Approved Rates

Margin ($ millions)	Approved 2018	Projected 2018	Forecast 2019
Residential [1]	484.373	476.073	484.743
Commercial [2]	235.159	232.118	237.390
Industrial [3]	102.501	108.744	114.086
Total	**822.033**	**816.935**	**836.218**

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), if they relate to use rate variances for residential and commercial customers, or the Flow-through deferral account, for all other variances.

3.7 SUMMARY

FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years, and provides a reasonable estimate of future natural gas demand for 2019. Based on these methods, FEI is forecasting an increase in consumption in 2019, with the total normalized demand forecasted to be approximately 235.4 PJs in 2019, up approximately 6.4 PJs from the 2018 projected consumption and up approximately 7.2 PJs from the 2018 Approved demand of 228.2 PJs. Based on the 2018 Approved rates for each customer class, FEI's 2019 revenue forecast is $1,205.500 million and 2019 gross margin forecast is $836.218 million.

4. COST OF GAS

The cost of gas includes the cost of the gas commodity and the cost of midstream resources (storage and transportation). 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 Commission. Any variations between forecast and actual gas costs will continue to be returned to, or recovered from, customers through the existing deferral account mechanisms.

While the Company is not requesting approval of forecast gas costs 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 existing (as of July 1, 2018) unit gas cost recovery charges for each rate schedule.

The natural gas commodity cost recovery rate for the Mainland, Vancouver Island, and Whistler service areas became effective January 1, 2018 pursuant to Commission Order G-173-17, dated November 30, 2017. The natural gas storage and transport rates and riders, also known as the midstream cost recovery rates and Midstream Cost Reconciliation Account (MCRA) rate riders, for the Mainland, Vancouver Island, and Whistler service areas became effective January 1, 2018 pursuant to Commission Order G-173-17, dated November 30, 2017.

The propane cost recovery rates for Revelstoke became effective July 1, 2018 pursuant to Commission Order G-112-18, dated June 14, 2018.

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[23]

Cost of Gas ($ millions)	Approved 2018	Projected 2018	Forecast 2019
Residential [1]	255.047	215.613	217.846
Commercial [2]	156.127	135.264	137.355
Industrial [3]	13.101	12.674	14.081
Total	**424.275**	**363.551**	**369.282**

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

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

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[24] via the gas cost rates. Whereas 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.

[24] 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*

As shown in the table below, FEI is forecasting other revenues to increase from the amounts approved for 2018, primarily due to an increase in SCP Third Party revenue.

Table 5-1: Other Revenue Components

Other Operating Revenue, ($ millions)			
	Approved 2018	Projected 2018	Forecast 2019
Late Payment Charge	2.688	2.503	2.546
Connection Charge	3.148	3.190	3.203
Other Recoveries	0.368	0.368	0.368
NGT Related Recoveries	4.297	3.876	4.377
Biomethane Other Revenue	0.532	0.464	0.614
SCP Third Party Revenue	16.976	16.976	17.072
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**46.048**	**45.416**	**46.220**

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

The forecast Late Payment Charge revenue is calculated as a percentage of total forecast revenue for Rate Schedule 1, 2 and 3 customers.[25] Specifically, FEI uses the three-year average of the actual ratio of Late Payment Charges to Rate Schedule 1, 2, and 3 revenues (Late Payment Charge Factor or LPC Factor) to calculate the 2019 forecast.

The following table summarizes the calculation of the Late Payment Charge Factor:

Table 5-2: Late Payment Charge Revenue Factor Calculation (revenues in $ millions)

		Actual 2015	Actual 2016	Actual 2017	3 Yr Average
FEI	Late Payment Charge	2.545	2.326	2.750	
FEI	Rates 1, 2, 3 Revenue	1,062.033	950.924	1,114.999	
Total	**LPC Factor**	**0.2396%**	**0.2446%**	**0.2466%**	**0.2437%**

[25] Includes Rate Schedules 1, 1B, 1U, 2, 2B, 2U, 3, 3B, 3U.

The Late Payment Charge factor of 0.2437 percent is multiplied by the forecast revenue for Rate Schedules 1 through 3 of $1,044.850 million to arrive at the forecast Late Payment Charge Revenue of $2.546 million for 2019.

5.2.2 Connection Charge

Consistent with the method used in previous years, the Connection Charge revenue is calculated based on three factors: a $25 connection fee[26], the historical move ratio of 12.5 percent[27] and the projected or forecast number of average customers.

In 2019, the number of average customers is forecast to increase; therefore, the forecast for Connection Charge revenue is also forecast to increase.

The following formula summarizes how FEI has calculated the 2019 forecast amounts in Connection Charge revenue:

Connection Charge of $25 * (Average Customers of 1,024,962) * Move Ratio of 12.5% = Connection Charge Revenue of $3.203 million.

5.2.3 Other Recoveries

Other recoveries consist of NSF returned cheque charges[28] as well as other miscellaneous income items. Consistent with past practice, the 2019 forecast of these items has been determined based on the 2018 projected amounts of $0.080 million and $0.288 million, respectively, for a total forecast of $0.368 million.[29]

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 5-3 below.

[26] Currently referred to as the Application Fee of $25 in the FEI General Terms and Conditions (the GT&Cs) Standard Fees and Charges Schedule. As part of FEI's 2016 Rate Design Application, FEI has been approved to reduce this charge to $15 and will be filing an Evidentiary Update to address this and other approved changes from the Rate Design Application.

[27] The historical move ratio reflects the percentage of customers that move from one location to another each year.

[28] Currently referred to as the Dishonoured Cheque Charge of $20 in the GT&Cs Standard Fees and Charges Schedule. As part of FEI's 2016 Rate Design Application, FEI has been approved to rename this charge the Returned Payment Charge and to reduce this charge to $7 and will be filing an Evidentiary Update to address this and other approved changes from the Rate Design Application.

[29] 2018 projected amounts are based on six months of 2018 actual information that was available at the time the forecast was prepared.

Table 5-3: 2018 and 2019 NGT Related Recoveries

NGT Related Recoveries, ($ millions)			
	Approved 2018	Projected 2018	Forecast 2019
NGT Overhead and Marketing Recovery	0.320	0.312	0.325
NGT Tanker Rental Revenue	0.583	0.510	0.680
CNG & LNG Service Revenues	3.394	3.055	3.373
Total NGT Related Recoveries	**4.297**	**3.876**	**4.377**

As discussed in Appendix B, Sections 5.4 and 6, overhead and marketing revenue has been determined based on the forecast of FEI-owned fuelling stations, tanker rental revenue has been forecast based on the 2018 projected delivery frequency, and the CNG and LNG service revenues have been forecast based on existing and forecast fuelling stations and volumes attributable to CNG and LNG customers for 2019. Please refer to Appendix B, Sections 5.4 and 6 for a more detailed discussion of each item.

5.2.5 Biomethane Other Revenue

The other revenue amount of $0.614 million in 2019 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 Commission 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[30]:

- Upgrading plant cost of service;
- Interconnection cost of service for projects introduced after Order G-210-13; and
- Program overhead costs.[31]

For 2019, FEI has transferred the earned return on capital and tax component of the cost of service related to the existing upgrading plants, and the City of Surrey Landfill project interconnection to the BVA by crediting Other Revenue.

With respect to other Biomethane capital expenditures, FEI notes that there is a forecast capital expenditure of $1.561 million[32] for interconnections related to projects approved before or as a part of Order G-210-13 that remain in the delivery margin, as clarified in Commission letter L-10-14, dated February 18, 2014 regarding Order G-210-13. FEI also notes that the transfer of the

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

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

[32] In Section 11, Schedule 4, Line 32, Column 4, the 2019 capital expenditure amount of $1.561 million includes $1.021 million for the Dickland project shifted into 2019, and $0.540 million for the delayed Lulu Island project, where the cost of service is recovered through the delivery margin as per Order G-210-13.

Biomethane upgrader O&M and program overhead costs to the BVA is accounted for in FEI's 2018 Approved and 2019 Forecast O&M (Section 11, Schedule 20, Line 42, Column 4).

5.3 SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE

The SCP Third Party Revenue for 2018 and 2019 includes the items shown in the table below.

Table 5-4: 2018 and 2019 SCP Revenue Components

Southern Crossing Pipeline Revenue, ($ millions)			
	Approved 2018	**Projected 2018**	**Forecast 2019**
Northwest Natural Gas Co. (NWN)	$ 6.482	$ 6.482	$ 5.764
MCRA	3.600	3.600	3.600
Net Other Mitigation - West to East Capacity	6.894	6.894	7.709
Total SCP Revenue	**$ 16.976**	**$ 16.976**	**$ 17.073**

The components of the SCP Third Party Revenues shown in Table 5-4 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 Northwest Natural Gas Co.

FEI has a firm service contract with Northwest Natural Gas Co. (NWN), approved in Order G-98-05, for 46.5 MMcfd of SCP capacity over the period November 2004 through October 2020. Consistent with the PBR Application, the NWN revenues are recorded net of the costs for the Spectra Energy (Spectra) Kingsvale South Transportation (Spectra tolls are subject to change from time to time) and the Pacific Gas & Electric (PG&E) termination fees as shown in Table 5-5 below.

Table 5-5: Calculation of 2018 and 2019 Northwest Natural Gas Co. Revenue

Forecast NWN Revenue, ($ millions)	2018	2019
NWN Revenue	$ 8.994	$ 8.994
Transportation Tolls (A)	(2.367)	(3.085)
PG&E Termination Fee	(0.145)	(0.145)
Net NWN Revenue	**$ 6.482**	**$ 5.764**

Notes: (A) Costs related to Spectra Kingsvale South capacity.

5.3.2 MCRA

The revenue of $3.6 million per year is related to the inclusion of SCP capacity in the MCRA portfolio. To realize the full benefits of a longer term for the PBR Plan, Order G-138-14 directed

FEI to extend the term of the PBR to the end of 2019 from the original proposal of 2018. However, through Order G-138-14, the Commission approved the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for only the **2014 to 2018** PBR Period. To align with the extension of the PBR term to the end of 2019, in this Application, FEI seeks approval for the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million for 2019, the last year of the current PBR term. Consistent with current practice, the MCRA will continue to pay for the cost of its portion of the Spectra Energy Kingsvale South capacity.

The Company believes that this treatment of costs and revenues is appropriate as the SCP capacity is an essential part of FEI's midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers.

5.3.3 Net Other Mitigation Revenue

The mitigation revenue associated with the west to east capacity on SCP during the initial years of the PBR term was the result of the T-South Enhanced Service agreement between Spectra and FEI. The T-South Enhanced Service agreement expired on October 31, 2016.

The Company has been, and will continue, to seek opportunities to contract the west to east capacity. The forecast mitigation revenue for the SCP west to east capacity for 2019 is based on the current forward market price differentials for summer 2019 and reflect the existing pipeline capacity constraints within the region. These market conditions will change over time and mitigation revenues are expected to moderate as regional constraints are addressed. FEI forecasts generating net mitigation revenue in the amount of $7.709 million in 2019.

The mitigation revenue forecast is net of the cost of using FEI gas supply resources, such as Spectra 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 to gas costs.

The Mt. Hayes cost allocations were reviewed during the FEI 2016 Rate Design Application proceeding and the Commission approved the Company'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.[33]

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

5.5 SUMMARY

FEI has forecast the Other Revenue components for 2019 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 CNG/LNG Recoveries deferral (for variances in the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4) or the Flow-through deferral account (for all other variances).

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the PBR Plan, 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 2019, the Formula O&M is $248.924 million, representing a 2.192 percent increase from the 2018 Formula O&M, entirely due to the formula drivers. O&M expenses forecast outside the formula are $32.209 million, representing a 0.509 percent increase from the amount approved for 2018. Overall the increase in Gross O&M Expense from 2018 to 2019 is 1.996 percent.

The components of 2019 O&M expense are shown in Table 6-1 below.

Table 6-1: 2019 O&M Expense

Line No.	Description	$ millions	Reference
1	Formula O&M	248.924	Table 6-2, Line 6
2	Forecast O&M	32.209	Table 6-3, Line 7
3	Total Gross O&M	281.133	
4	Capitalized Overhead (12%)	(33.736)	Section 11, Schedule 20, Line 43
5	Biomethane O&M transferred to BVA	(1.322)	Section 11, Schedule 20, Line 42
6			
7	Net O&M	246.075	

In the subsections below, FEI provides further details on its formula and forecast O&M expenses for 2019.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of Base O&M starts from a base of the 2018 Approved formula O&M for FEI, escalated by the prior year's inflation less a productivity improvement factor of 1.1 percent, and one-half of the prior year's growth in average customers. As calculated in Section 2, the 2019 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 1.405 percent and one-half of the prior year's customer growth is 0.776 percent.

For 2019, the annual operating and maintenance expense under the formula is calculated as:

2018 Approved formula O&M x [1 + (I Factor – X Factor)] x [1 + (0.5 x customer growth)]

Table 6-2 below shows the calculation of the 2019 Formula O&M.

Table 6-2: Calculation of 2019 Formula O&M

Line No.	Description	Amount ($ millions)	Reference
1	2018 Formula O&M	243.585	FEI 2018 Rates Compliance Filing Schedule 20, Line 23, Column 4
2			
3	Net Inflation Factor	1.405%	Section 2, Table 2-4
4	Customer Growth Factor	0.776%	Section 2, Table 2-2
5			
6	2019 Formula O&M	248.924	Line 1 x (1 + Line 3) x (1 + Line 4)

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

The Formula O&M is then adjusted to add in pension and OPEB expense, insurance, O&M supporting Biomethane, NGT, and Rate Schedule 46, as well as any exogenous factors (the O&M impacts of the Employer Health Tax and the reduction in MSP costs). These amounts are shown in Table 6-3 below along with a comparison to 2018.

Table 6-3: 2019 Forecast O&M ($ millions)

		2018		2019
Line No.	Description	Approved	Projected	Forecast
1	Pension/OPEB (O&M Portion)	17.077	17.077	13.795
2	Insurance	5.360	5.284	5.473
3	Biomethane O&M	1.121	1.929	1.369
4	NGT O&M	1.838	1.660	2.339
5	RS 46 O&M	6.650	6.506	7.432
6	EHT	-	-	2.630
7	MSP reduction	-	(0.829)	(0.829)
8				
9	Forecast O&M	32.046	31.627	32.209

Each of these 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. Variances in insurance, net Biomethane O&M, NGT O&M, Rate Schedule 46 O&M, and the O&M portion of the Z Factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expenses for 2019 are based upon actuarial estimates using a range of assumptions as at December 31, 2017 provided by the Company's actuary, Willis Towers Watson. Pension and OPEB expense is segregated amongst O&M, Capital, Asset Removal Costs, and Core Market Administration Expense (CMAE) categories as shown in Table 6-4.

Table 6-4: 2018-2019 Pension and OPEB Expense ($ millions)

Line No.	Description	2018 Approved	2019 Forecast
1	Forecast O&M	17.077	13.795
2	Forecast Capital - Growth	0.795	0.903
3	Forecast Capital - Other	2.334	2.661
4	Deferral - Asset Removal Costs	0.913	1.050
5	Deferral - CMAE	0.278	0.317
6			
7	Total Pension & OPEB Expense	21.397	18.727

Overall, 2019 pension and OPEB expense is forecasted to be $2.670 million lower than the amount approved for 2018. This decrease is primarily due to higher expected return on assets and to a lesser extent by a reduction in expected OPEB claims costs, which is primarily due to a reduction in MSP premiums, partially offset by a decrease in the discount rate.

The majority of the pension and OPEB expense variance resides in the allocation to O&M since the variance is primarily attributable to a higher expected return on assets which is recognized in O&M, partially offset by a higher current service cost.

The 2018 variance between approved and actual pension and OPEB expense and any variance from these forecasted 2019 amounts is captured in the Pension and OPEB Variance deferral account and amortized into rates over a three year period as approved in by the Commission in Order G-138-14.

6.3.2 Insurance

The insurance expense relates to insurance premium expense allocated to FEI by Fortis Inc.

The 2019 insurance expense is forecast at $5.473 million, an increase of $0.113 million or 2.1 percent from what was approved for 2018. The 2019 Forecast is calculated by taking the known annual insurance premium of $5.339 million which is applicable to the first six months of 2019 and escalating that amount by five percent for the remaining six months[34]. In forecasting insurance premium increases, FEI uses a five percent escalation unless there are indications which suggest significant increases are forthcoming as a result of loss history for the Company or the industry as a whole.

6.3.3 Biomethane O&M

A summary of the 2018 approved and projected and 2019 forecast Biomethane O&M, by project, is provided in Table 6-5 below:

[34] $5.339 million/2 = $2.670 million x 1.05 = $2.803 million. $2.670 million + $2.803 million = $5.473 million.

Table 6-5: Biomethane O&M by Project ($ millions)

Line No	Description	2018 Approved	2018 Projected	2019 Forecast
1	Program Overhead	0.545	0.912	0.986
2	City of Surrey biofuel	0.011	0.081	0.010
3	Kelowna upgrader	0.318	0.673	0.147
4	Salmon Arm upgrader	0.200	0.218	0.180
5	New 2018 Project	-	-	-
6	**Sub-total - Transferred to BVA**	**1.074**	**1.884**	**1.322**
7				
8	Fraser Valley Biogas	0.011	0.011	0.011
9	Salmon Arm Landfill	0.011	0.011	0.011
10	Kelowna Landfill	0.011	0.011	0.011
11	Seabreeze Farms	0.011	0.011	0.011
12	Lulu Island WWTP	0.003	-	0.001
13	Dicklands Farm	-	-	-
14	**Sub-total - Recovered in delivery rates**	**0.047**	**0.043**	**0.046**
15				
16	**Total Biomethane O&M**	**1.121**	**1.928**	**1.369**

The 2019 forecast of total Biomethane O&M is $1.369 million as shown in the table above. Of this total, $1.322 million (shown in Table 6-1 above) relates to upgrader O&M, interconnection O&M and program overhead[35] which is transferred to the BVA for recovery through the Biomethane Energy Recovery Charge (BERC). The remaining O&M of $0.046 million is the O&M associated with interconnection stations which pre-dated or were approved in Order G-210-13[36], and is recovered through delivery rates.

The 2019 forecast O&M of $1.369 million is $0.248 million higher than the 2018 Approved O&M primarily due to assignment of additional resources to support supply development to meet the growing demand. This increase is partially offset by an estimate for the recovery of costs for the Kelowna fire insurance claim. In December 2017 there was a fire at the Kelowna upgrader and the remediation costs were recorded in 2018 with the expected net insurance claim recovery of approximately $0.213 million occurring in 2019.

The 2018 Projected O&M of $1.928 million is $0.807 million higher than the 2018 Approved O&M of $1.121 million. This is due to under forecasting of resources by approximately $0.367 million, the Kelowna upgrader fire remediation cost of approximately $0.463 million (partially offset by lower operating costs during remediation) and the Surrey interconnection regulatory proceeding costs $0.075 million.

[35] The 2019 forecasted Program Overhead of $986 thousand is comprised of $318 thousand for Customer Education costs, $60 thousand in future development costs and $608 thousand for resourcing.

[36] These projects were Fraser Valley Biogas, Salmon Arm Landfill, Kelowna Landfill, Seabreeze Farms, Lulu Island WWTP, and Dicklands Farm.

6.3.4 NGT O&M

NGT O&M is forecast to increase by $0.501 million from what was approved for 2018. The total NGT O&M of $2.339 million is composed of $1.469 million of NGT station O&M and $0.870 million of LNG tanker and related O&M (Appendix B Sections 5.3, 5.5.3 and 6.1.2, and Table B-16). These O&M costs are offset by NGT revenue as discussed in Appendix B Section 4.2. Please refer to Appendix B NGT for a discussion of these amounts.

6.3.5 Incremental O&M to Support Rate Schedule 46

The O&M costs to support Rate Schedule 46[37] include all incremental costs associated with the liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers and iso-containers to supply LNG from the Tilbury and Mt. Hayes LNG facilities. These costs are incremental to the regular O&M costs for operating the Tilbury and Mt. Hayes LNG facilities as peaking storage facilities.

A table breaking out the various components of the Rate Schedule 46 O&M is included below.

Table 6-6: Rate Schedule 46 O&M ($ millions)

	2018		2019
Description	Approved	Projected	Forecast
Tilbury Plant:			
labour	2.540	2.181	2.800
Materials	0.083	0.083	0.105
Contractor	0.719	0.719	0.719
Power	2.847	3.064	3.072
Fuel Gas	0.127	0.125	0.108
Fees & Administration	0.160	0.160	0.160
Sub-total	6.476	6.332	6.964
Mt. Hayes Plant:			
Labour	0.056	0.056	0.153
Materials	0.008	0.008	0.025
Contractor	0.013	0.013	0.054
Power	0.089	0.089	0.200
Fuel Gas	0.008	0.008	0.036
Sub-total	0.174	0.174	0.468
Forecast O&M	6.650	6.506	7.432

[37] Information on Rate Schedule 46 and associated revenues is provided in Appendix B: NGT.

The O&M expense required for operation of the Expanded Tilbury LNG facility[38] and the Mt Hayes LNG facility is projected to be $6.506 million in 2018. The 2018 Projected expense is relatively unchanged from the 2018 Approved amount with a decrease of approximately two percent. The variance is primarily due to a decrease in labour cost requirement due to the timing for the hire of new employees, offset by an increase in power costs largely associated with increased liquefaction activity compared to the original 2018 forecast.

The 2019 Forecast O&M costs to support Rate Schedule 46 are estimated to increase from the 2018 Approved amount by approximately $0.782 million. The increase in O&M at the Tilbury plant is primarily a result of increased labour costs for additional staff to fully support the current demand for Rate Schedule 46 LNG sales. In addition, power costs are forecast to increase primarily due to higher forecasted liquefaction activity in 2019. Finally, material costs for maintenance is forecasted to be slightly higher in 2019 offset by a similar reduction in fuel gas costs.

The increase in expense at the Mt. Hayes plant is primarily related to the increase in demand for Rate Schedule 46 LNG sales requiring an increase in liquefaction activity, resulting in higher labour costs, power costs, process materials costs, fuel gas costs and contractor costs.

6.3.6 Employer Health Tax (EHT)

The EHT will come into effect on January 1, 2019, as announced in the February 2018 provincial budget. The EHT qualifies as an exogenous factor, as described in Section 12.2.1. The EHT is a payroll tax, some details of which are still to be determined through pending legislation. FEI's current forecast for EHT in 2019 is $3.294 million, of which $2.630 million is included in labour loadings to O&M expense, with the remainder a reduction in capital expenditures, asset removal costs which are recorded in the net salvage deferral and Core Market Administration Expense (CMAE) which is recovered through the CCRA. Variances from amounts forecast will be returned to or recovered from customers in future years.

Table 6-7 below provides the components of forecast EHT in 2019.

Table 6-7: Exogenous Factor EHT Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Forecast O&M	-	-	2.630
2	Forecast Capital - Growth	-	-	0.122
3	Forecast Capital - Other	-	-	0.359
4	Deferral - Asset Removal Costs	-	-	0.140
5	Deferral - CMAE	-	-	0.043
6	**Total EHT Expense**	**-**	**-**	**3.294**

[38] The expanded LNG facility is the phase 1A facilities defined in Direction No. 5 to the British Columbia Utilities Commission, B.C. Reg. 245/2013, as amended by B.C. Reg. 265/2014.

6.3.7 Medical Services Plan (MSP) Premium Reduction

Effective January 1, 2018, provincial MSP premiums were reduced by 50 percent. This reduction qualifies as an exogenous factor, as described in Section 12.2.2. FEI forecasts a reduction in O&M expense of $1.038 million in each of 2018 and 2019, of which $0.829 will be a reduction of labour loadings in O&M expense, with the remainder a reduction to capital expenditures, asset removal costs which are recorded in the net salvage deferral and CMAE which is recovered through the CCRA. Variances from amounts forecast will be returned to or recovered from customers in future years.

Table 6-8 below provides the components of the forecast MSP premium reduction in 2018 and 2019.

Table 6-8: Exogenous Factor MSP Premium Reduction ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Forecast O&M	-	(0.829)	(0.829)
2	Forecast Capital - Growth	-	(0.039)	(0.039)
3	Forecast Capital - Other	-	(0.113)	(0.113)
4	Deferral - Asset Removal Costs	-	(0.044)	(0.044)
5	Deferral - CMAE	-	(0.013)	(0.013)
6	**Total MSP Premium Reduction**		**(1.038)**	**(1.038)**

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 Commission in Order G-138-14, the capitalized overhead rate is set at 12 percent for FEI. After capitalized overhead and the transfer of $1.322 million of Biomethane O&M to the BVA, the net O&M expense is $246.075 million.

6.5 SUMMARY

Overall the increase in Gross O&M Expense from Approved 2018 to 2019 is 1.996 percent. The formula-driven O&M is increasing at a rate of 2.192 percent with the O&M forecast outside of the formula increasing at a rate of 0.509 percent. The capitalized overhead rate remains unchanged from 2018.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

The 2019 Rate Base for FEI is forecast to be $4.481 billion. Rate Base is composed 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.

The 2019 Rate Base of FEI includes the full-year impacts of the 2018 closing projected 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 $208.396 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $190.089 million;
- Full-year impact of the first phase of the LMIPSU Project at $70.942 million[39]; and
- Full-year impact of the capital formula dead band adjustment of $54.145 million[40] as discussed in Section 1.4.4.

In addition, various changes in deferred charges, working capital and other items reduce rate base by a net amount of $46.796 million.

Details of the 2019 forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 2019 REGULAR CAPITAL EXPENDITURES

Under the PBR Plan, FEI's regular capital expenditures are primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2019, the formula-capital is $157.249 million[41], representing a 3.398 percent increase from 2018, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $25.210 million, representing a 231.279 percent increase from 2018, primarily due to increased spending on Biomethane and NGT assets and higher pension & OPEB costs. Overall, gross regular capital expenditures are forecast to increase from 2018 to 2019 by 17.727 percent. The components of 2019 regular capital expenditures are shown in Table 7-1 below.

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39 The rate base calculation assumes a mid-year addition for capital expenditures. This has been adjusted to recognize a full year impact of this project using the "Adjustment for Timing of Capital Additions" line in Section 11, Schedule 2.

40 $56.532 million included as an opening adjustment to Gross Plant in Section 11, Schedule 6.2, Line 34 and ($2.387) million recognized as an opening adjustment to CIAC in Section 11, Schedule 9, Line 6 = $54.145 million.

41 From Table 7-1 $157.249 million = $40.140 million + 123.921 million - $6.812 million.

Table 7-1: 2019 Regular Capital Expenditures

Line No.	Description	$ millions	Reference
1	Formula Growth Capex	40.140	Table 7-2, Line 6
2	Formula Other Capex (before CIAC)	123.921	Table 7-3, Line 6 - CIAC amount from Line 5 below
3	Forecast Capex	25.210	Table 7-4, Line 7
4	Total Gross Regular Capex	189.271	
5	Less: Formula CIAC	(6.812)	Section 11, Schedule 4, Line 39 + 40
6			
7	Net Regular Capex	182.459	

In the subsections below, FEI provides further details on its formula and forecast capital expenditures for 2019.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2018 approved formula capital, escalated by the prior year's inflation less a productivity improvement factor of 1.1 percent, and one-half of the prior year's growth in average customers or service line additions. As calculated in Section 2, the 2019 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 1.405 percent, one-half of the prior year's average customer growth is 0.776 percent, and one-half of the prior year's service line additions growth is 5.600 percent. In accordance with Order G-138-14, regular capital expenditure amounts will not be rebased to actual amounts during the PBR term, except that if the capital dead band is exceeded, FEI will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year, as described in Section 1.4.4.

Unlike the O&M formula, the capital expenditure formula has two growth components in addition to formula inflation, resulting in separate calculations of Growth Capital and Other Capital. For 2019, the annual capital expenditures under the formula are calculated as:

2019 Growth Capital = 2018 Growth capital x [(1 + (I Factor – X Factor)] x [1 + SLA customer growth][42]

2019 Other Capital = 2018 Other Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth][43]

Tables 7-2 and 7-3 below show the calculation of the resulting 2019 formula capital expenditures.

[42] SLA customer growth factor as calculated in Section 2, Table 2-2. The formula may also be represented as 2019 Growth Capital = 2018 Growth capital per SLA x [(1 + (I Factor – X Factor)] x 2019 SLA.

[43] This formula is also applied to contributions in aid of construction.

Table 7-2: Calculation of 2019 Formula Growth Capital

Line No.	Description	($ millions)	Reference
1	2018 Formula Growth Capex Base	37.485	FEI 2018 Rates Compliance Filing Schedule 4 Line 21 Column 2
2			
3	Net Inflation Factor	1.405%	Section 2 Table 2-4
4	Customer Growth Factor	5.600%	Section 2 Table 2-3
5			
6	2019 Formula Growth Capex	40.140	Line 1 x (1 + Line 3) x (1 + Line 4)

Table 7-3: Calculation of 2019 Formula Other Capital

Line No.	Description	($ millions)	Reference
1	2018 Formula Other Capex Base	114.597	FEI 2018 Rates Compliance Filing Schedule 4 Line 21 Column 3
2			
3	Net Inflation Factor	1.405%	Section 2 Table 2-4
4	Customer Growth Factor	0.776%	Section 2 Table 2-2
5			
6	2019 Formula Other Capex	117.109	Line 3 x (1 + Line 5) x (1 + Line 6)

The formula Other Capital amount of $117.109 million is net of CIAC. The amount of CIAC is $6.812 million, which is required to be separated for purposes of the financial schedules and rate calculations. Therefore, the gross formula Other Capital amount is $123.921 million as shown in Table 7-1 above.

7.2.2 Regular Capital Expenditures Forecast Outside the Formula

To calculate total regular capital expenditures, the formula capital expenditures are adjusted to add in pension and OPEB expense, Biomethane and NGT capital expenditures, and the capital portions of the exogenous factors (the EHT and reduction in MSP), which are forecast outside the formula. These amounts are shown in Table 7-4 below along with a comparison to 2018.

Table 7-4: 2019 Forecast Regular Capital Expenditures ($ millions)

		2018		2019
Line No.	Description	Approved	Projected	Forecast
1	Pension/OPEB (Capital Portion)	3.128	3.128	3.565
2	Biomethane Upgraders		0.100	11.300
3	Biomethane Interconnect	0.840	0.060	1.561
4	NGT Assets	7.690	4.359	8.455
5	Employer Health Tax			0.481
6	MSP		(0.152)	(0.152)
7	Forecast Regular Capex	11.658	7.495	25.210

Each of the items forecast outside of the formula is described further below.

- The forecast Pension and OPEB capital expenditures of $3.565 million represent the forecast capital portion of the total Pension and OPEB costs for 2019. Pension and OPEB costs are described in Section 6.3.1.
- The $0.100 million Biomethane Upgraders capital expenditures projected for 2018 is for the Salmon Arm Upgrader. This unanticipated investment was required to build a structure for weather protection and to relocate a compressor to improve year-round operability of the facility. The $11.300 million expenditure forecast for 2019 relates to the City of Vancouver biomethane project (CoV Project), which is located in Delta BC, at the landfill site owned and operated by the CoV. The CoV Project will consist of an upgrading plant and interconnection to FEI's natural gas distribution infrastructure; however, FEI has shown the entire expenditure in the upgrader line as final details are still being finalized. FEI will be filing an application to the Commission regarding the CoV Project in 2018.
- The forecast Biomethane Interconnect capital expenditures of $1.561 million in 2019 is for two interconnection projects, consisting of the delayed Lulu Island Waste Water Treatment Plant ($0.540 million) and the Dickland project ($1.021 million). The Lulu Island project was delayed from 2018 and will be placed into service at the end of 2019. The cost of service for both the Dickland and Lulu Island interconnection remains in the delivery margin as clarified in Commission Letter L-10-14, dated February 18, 2014 regarding Order No. G-210-13.
- The forecast NGT Assets capital expenditures of $8.455 million are the forecasts for NGT Fuelling Stations and Tankers (Appendix B, Section 7, Table B-16 amounts of $6.105 million and $2.350 million).
- The EHT forecast of $0.481 million is the forecast capital portion of the total EHT costs for 2019. These costs are described in Sections 6.3.6 and 12.2.1.
- The capital portion of the MSP premium reduction is forecast at $0.152 million in each of 2018 and 2019. The MSP premium reduction is discussed in Sections 6.3.7 and 12.2.2.

7.2.2.1 CPCN and Special Project Capital Expenditures

Also forecast outside of the formula are any capital expenditures related to approved CPCNs and other projects which are proceeding as a result of an Order in Council. In 2019, FEI is forecasting capital expenditures related to the Tilbury Expansion Project, and the LMIPSU Project. The Tilbury Expansion Project and the Vancouver section and East 2nd and Woodland station portions of the LMIPSU project are forecast to be included in rate base and affect delivery rates in 2019. Each project is discussed below.

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 Orders in Council (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). At this time, completion is expected late in 2018 for the first $469 million of the costs ($400 million excluding AFUDC and feasibility and development costs), with the remaining $25 million plus AFUDC expected to be complete in future years.

Table 7-5: Tilbury Expansion Project ($ millions)

Description	Dec 31, 2018 Projected	2019 Onwards	Total
Capital Expenditures	400.000	25.000	425.000
Feasibility & Development	6.494	0.000	6.494
AFUDC	62.396	0.755	63.151
Total	**468.890**	**25.755**	**494.645**

In FEI's Annual Review for 2018 Rates, the Tilbury Expansion Project was included in rate base on January 1, 2018. As described in the response to CEC IR 1.19.2 at that time:

> The completion of the Tilbury Expansion Project has been delayed due to an incident that occurred on August 19, 2017. The Contractor conducting the start-up/commissioning of the plant reported a brief ignition from a refrigerant line, which was extinguished shortly thereafter. Fire detection and suppression equipment on site was activated and functioned as designed, containing the incident. Emergency response procedures were also activated and worked as planned. However, the investigation into the cause of the fire and any necessary repairs will delay the completion of the project at least until the end of 2017. As a consequence, FEI has revised the date for the Tilbury Expansion to be included in rate base to January 1, 2018. An Evidentiary Update reflecting this change is being filed concurrently with these IR responses on September 26, 2017.

After the repairs related to the fire incident, the start up of the Tilbury Expansion Project was further delayed due to the discovery of a design flaw in a component of the plant that removes hydrocarbons and mercaptans before liquefaction. A solution has now been identified and the facility is scheduled to re-start commissioning and LNG production prior to the end of 2018.

As stated above, FEI's Annual Review for 2018 rates included the Tilbury Expansion Project in rate base on January 1, 2018. Consequently, the full cost of service including depreciation, earned return and taxes of the Tilbury Expansion was included in 2018 rates. FEI is now including the Tilbury Expansion Project in rate base on January 1, 2019. The 2018 cost of service items will be returned to customers through FEI's Flow-through deferral account as described in Section 12.4.2.2; the earned return is discussed below.

Since, for rate making purposes, the Tilbury Expansion Project was placed into rate base starting on January 1, 2018, FEI discontinued recording AFUDC on the project at that time. Instead, FEI collected its earned return through inclusion in rate base. FEI has thus been kept whole for 2018 on this component of the project, which does not need to be captured in the Flow-through deferral account.

In summary, FEI is proposing to include the Tilbury Expansion Project in rate base on January 1, 2019. Both FEI and customers are held whole through a combination of the Flow-through deferral account (for depreciation, property taxes, and income taxes) and the recovery of the earned return through rate base in 2018 instead of through AFUDC.

LMIPSU PROJECT CPCN

The LMIPSU Project CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU Project includes the Coquitlam Gate IP Project, which will address an increasing number of gas leaks on the Coquitlam Gate IP line and restores operational flexibility and resiliency to the Metro Vancouver IP system. The LMIPSU Project also includes the Fraser Gate IP Project, which will provide required seismic upgrades to the Fraser Gate IP line. Only the Vancouver section of the Coquitlam Gate IP Project and the East 2nd and Woodland station are forecast to be in service in 2018, and to be added to rate base January 1, 2019. The projected cost of the Vancouver section and of the East 2nd & Woodland Station equal $59.151 million and $11.791 million respectively totalling $70.942 million added to rate base January 1, 2019. The estimated capital cost for the LMIPSU Project, including AFUDC and abandonment/demolition costs, is $511.517 million. FEI forecasts expenditures of $168.832 million and $171.642 million[44] in 2018 and 2019, respectively. The 2019 capital expenditures are forecasted to be added to rate base in future years, and are therefore not included in 2019 delivery rates.

7.3 *2019 PLANT ADDITIONS*

The 2019 Plant Additions are comprised of (i) FEI's 2019 regular capital expenditures from Section 7.2 above plus the Tilbury Expansion Project and the Vancouver section of the LMIPSU 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 Schedule 5 in Section 11.

[44] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 11.

Table 7-6: Reconciliation of Capital Expenditures to Plant Additions

Line No.	Description	$ millions	Source
1	Formula Growth Capex	40.140	Table 7-2
2	Formula Other Capex	117.109	Table 7-3
3	Forecast Capex	25.210	Table 7-4
4	Total Net Regular Capex	182.459	
5	Formula CIAC	6.812	Table 7-1
6	Total Gross Regular Capex	189.271	
7	Capitalized Overheads	33.736	Table 6-1
8	AFUDC	2.912	Section 11, Schedule 5, Line 21
9	Change in Work in Progress	(11.711)	
10	Total Regular Additions to Plant	**214.208**	
11			
12	Special Projects and CPCN Capex		
13	LMIPSU	171.642	Section 11, Schedule 5, Line 26
14	Special Projects and CPCN AFUDC	15.258	Section 11, Schedule 5, Line 27
15	Change in Special Projects and CPCN Work in Progress	352.931	Section 11, Schedule 5, Line 29
16	Total Special Projects and CPCN Additions to Plant	**539.831**	
17			
18	Total 2019 Plant Additions	**754.039**	

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 2019 were approved by Order G-119-16, and are based on the utility's most recent depreciation study. Depreciation is calculated starting January 1 of the year after the assets are placed in service, which is the treatment approved in Commission Order G-138-14.

Based on calculating depreciation expense at these proposed depreciation rates on the opening plant-in-service balance net of CIAC, the 2019 depreciation expense is calculated as $190.117 million[45].

7.5 DEFERRED CHARGES

On May 3, 2017, the Commission issued its Regulatory Account Filing Checklist[46]. The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the Commission.

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;

[45] $199.110 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $8.993 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

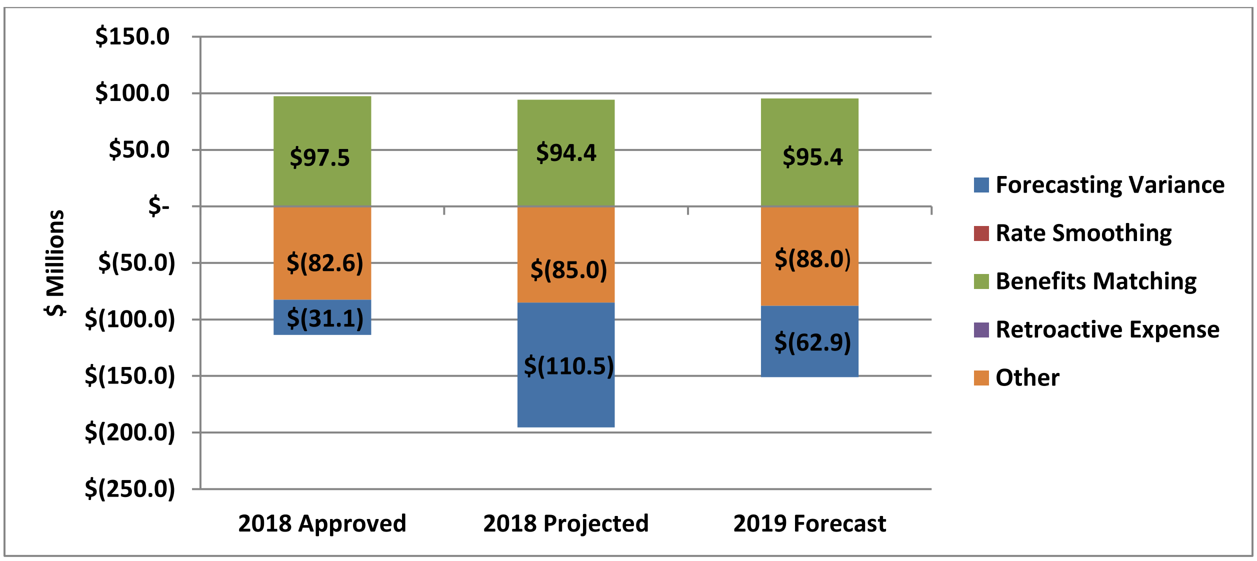
[46] Log No. 53608, Appendix B.

or (e) other. In Section 11, Schedule 11, 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 $55.479 million in 2019 and this 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, Commodity Cost Reconciliation Account, Revenue Stabilization Adjustment Mechanism, Deferred Interest on MCRA, CCRA, RSAM and Gas in Storage and Emissions Regulations, while partially offset by the Energy Efficiency and Conservation, Greenhouse Gas Reductions Regulation Incentives, Gains and Losses on Asset Disposition, Whistler Pipeline Conversion and 2011 Customer Service O&M and COS deferrals.

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 2019 amortization expense is calculated as $36.067 million[47]. The section below includes 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 one new rate base deferral account to capture the FEI portion of the costs related to the 2019-2022 Demand Side Management Expenditures Application. Table 7-7 below addresses the considerations identified in the Regulatory Account Filing Checklist, as

[47] Total of Section 11, Schedule 11.1, Line 24, Column 6 and Schedule 12, Line 23, Column 6.

they pertain to deferral accounts for regulatory proceedings generally, and the deferral account requested in section 7.5.1.1 below.

Table 7-7: 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 one new deferral account to capture the FEI portion of the costs related to the 2019-2022 Demand Side Management Expenditures Application and regulatory 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 account is a 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 the account encompasses the preparation and filing of the relevant regulatory application and its review by the Commission.
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 PBR formula O&M since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FEI considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is more simple to track and report on.

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 Commission and the degree of involvement of interveners.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FEI forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the PBR Plan. See section 7.5.1.1.
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. 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 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 Commission's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M Expense.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.

Item	Consideration	Determination
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.
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.	Deferral account approvals and disposition are generally determined in revenue requirements proceedings. Where requested within CPCN or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.5.1.1 2019-2022 Demand Side Management Expenditures Application

On June 22, 2018, FEI filed the 2019-2022 Demand Side Management Expenditures Application for approval of DSM Expenditures for 2019-2022. A written public hearing is anticipated for the review of this application; FEI estimates the costs at $0.300 million ($0.219 million after tax). FEI will also allocate a portion of these costs to FEFN customers based on the number of FEFN customers as a proportion of the total number of FEI and FEFN customers.

FEI requests approval to capture the full costs of the 2019-2022 Demand Side Management Expenditures Application in a rate base deferral account and to amortize the costs over four years, beginning in 2019, which represents the time period of costs covered by the application. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates in the following years.

7.5.2 Existing Deferral Accounts

In the discussion below, FEI is requesting modification of the 2017 Long-Term Resource Plan (LTRP) Application deferral account to capture regulatory proceeding costs and proposing a five-year recovery period for the 2017 Rate Design Application deferral account. Table 7-7 above addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to deferral accounts for regulatory proceedings generally.

7.5.2.1 2017 Long-Term Resource Plan Application

FEI is requesting to expand the scope of the 2017 LTRP Application deferral account to include the recovery of regulatory proceeding costs.

As part of the Annual Review for 2016 Rates Application, FEI requested the approval of the 2017 LTRP Application deferral account to capture the costs of external resources that were incremental to the costs in FEI's Base O&M for the LTRP development.

Commission Order G-193-15 approved the 2017 LTRP Application deferral account, subject to the following limitations on inclusion of costs for external resources:

a) Eligible costs for external resources are limited to required external resources that are incremental to the costs included in the FEI base O&M under the PBR; and

b) A maximum of $1.050 million over two years, whereby FEI must submit any amounts in excess of this to the Commission for approval prior to committing to those excess expenditures.

As described in Table 7-8, from Appendix C2 of the Annual Review for 2016 Rates Application, the $1.050 million in approved expenditures was to capture only specific cost categories related to the LTRP Application. FEI incurred expenditures in these categories throughout 2016, 2017 and 2018. The duration of these expenditures exceeds the stipulated two-year period for two reasons: (1) per Order G-99-17 and a letter, dated November 24, 2017, the Commission approved extensions to the Application filing deadline from June 30, 2017, to December 14, 2017, and (2) the Application's written public hearing process is ongoing and has not been completed yet.

Table 7-8: 2017 LTRP Approved Deferral Costs

Activity	Total Approved Expenditure
Scenario Development	$ 75,000
Comparison of End-Use Demand Forecasting Methodologies	$ 45,000
Alternative Residential and Commercial Customer Additions Forecast	$ 25,000
End-Use Demand Forecast	$ 180,000
Alternative Industrial Customer Additions and Demand Analysis	$ 145,000
Impact of New End-Use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 150,000
Incremental Consultation Activities	$ 50,000
DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$ 200,000
Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 80,000
Infrastructure Contingency Plans	$ 70,000
Analysis of Impact on GHG Targets	$ 30,000
Total	**$ 1,050,000**

To date, total actual costs for this work have been $0.431 million with a further $0.100 million of expected costs by the time the regulatory proceeding for the LTGRP is completed and a small amount of related stakeholder consultation in 2019. Costs have been lower than the original estimate as a result of FEI being able to complete more of the work using its own internal resources than originally estimated, as well as obtaining better commercial terms from external consultants than was estimated when preparing Table 7-8. The timing of these expenditures have been extended as a result of receiving approval from the Commission to extend the submission date for the LTGRP from June to December 2017 and continued work on these activities required to complete the regulatory proceeding.

With this Application, FEI is requesting approval to also capture the legal fees, intervener and participant funding costs, Commission costs, required public notification costs, and miscellaneous administrative costs related to the LTRP Application, which are currently forecasted at approximately $0.260 million, in this existing deferral account. FEI is seeking recovery of these costs, given they also were not included in the FEI base O&M under the PBR. This request is similar to other requests FEI has made previously to recover application and regulatory proceeding related costs through deferral accounts. FEI believes this is the appropriate account to use given the account was already created to capture costs related to the LTRP that were not embedded in FEI's formula O&M.

Furthermore, in this Application, FEI is seeking approval to amortize the 2017 LTRP deferral account over three years beginning in 2019. This amortization period is appropriate as it reflects the average expected period covered by a LTRP until the next LTRP is filed.

7.5.2.2 2017 Rate Design Application

As part of the Annual Review for 2015 Rates Application, FEI received approval through Commission Order G-86-15 to establish the 2017 Rate Design Application deferral account to capture the costs related to filing that application and the regulatory proceeding to review it. FEI noted in that it would request an amortization period for this account in an upcoming annual review filing once there was greater certainty over the process and forecast balance of this deferral account.

Given this proceeding has concluded in 2018, FEI is now seeking approval to amortize these costs over five years beginning in 2019. This amortization period is appropriate given it is consistent with other recovery periods for regulatory proceeding related costs and FEI expects to file a new COSA study within five years as directed by Commission Order G-4-18.

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 Commission Order G-44-12 and updated through Commission Order G-138-14.

Other working capital includes gas in storage, transmission line pack gas, and inventory of materials and supplies, less 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 2018 Q2 gas cost report and historical volumes. Materials and supplies and refundable contributions are forecast based on 2017 levels.

7.7 SUMMARY

FEI's rate base includes the impact of both formula-driven capital expenditures and those 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 one new account and the modification and disposition of two 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 consistently 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 2019 forecast 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 Rate for 2019 (which is equal to its after-tax weighted average cost of capital) is 5.66 percent. Variances in the interest expense recovered in rates will be recorded in the Flow-through deferral account for return to or recovery from customers in the following year.

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 Commission from time to time. Pursuant to Order G-129-16, the Commission 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. As part of Order G-129-16, the Commission issued an indefinite suspension of the Automatic Adjustment Mechanism.

FEI has therefore prepared this Application using an ROE of 8.75 percent and a common equity percentage of 38.5 percent.

8.3 FINANCING COSTS

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

8.3.1 Long-Term Debt

FEI is a public issuer of long-term debt. During October 2017, FEI issued long term debt of $175 million at a rate of 3.69 percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Corporation's capital expenditure program. FEI plans to issue additional long-term debt of approximately $150 million in 2018, and $150 million in 2019, which will be used for the same purpose. The 2018 debt issuance is reflected in the financial schedules in November 2018 at a rate of 3.90 percent[48]. The 2019 debt issuance is reflected in the financial schedules in July 2019 at a rate of 4.30 percent[49]. The exact timing, amount and rate of the 2018 and 2019 issuances will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the

[48] As shown in the financial schedules in Section 11, Schedule 27, Line 14.
[49] As shown in the financial schedules in Section 11, Schedule 27, Line 15.

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 by maintaining a $700 million committed credit facility that currently matures in August 2022[50]. The credit facility provides FEI with short term liquidity to fund FEI's capital program and working capital requirements.

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 currently expects to issue long term debt in 2019 at an estimated issue rate of approximately 4.30 percent based on a 30 year GOC rate of 3.00 percent and an indicative spread of 1.32 percent.

FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian 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 off of CDOR and so 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 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. To then derive the short-term borrowing rate forecast, FEI further 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 rate is projected to increase from 1.36 percent in 2018 to approximately 2.05 percent in 2019. The short-term borrowing rate forecast is shown in Table 8-1 below.

[50] As at July 27, 2017, credit facility extended to August 24, 2022.

Table 8-1: Short Term Interest Rate Forecast[1]

FEI Short Term Interest Rate	2018	2019
3-Month T-Bill Rate[1]	1.36%	2.05%
Spread to CDOR	0.42%	0.42%
CDOR Rate	1.78%	2.47%
Spread to CP	-0.17%	-0.17%
CP Dealer Commission	0.10%	0.10%
Standby Fee on Undrawn Credit[2]	0.40%	0.54%
Upfront Fee on Undrawn Credit	0.11%	0.15%
FEI Short Term Rate (Rounded)	**2.20%**	**3.10%**

Note 1 - 3-Month T-Bill rate for 2018 based on a composite of actual historical rates up to March 31, 2018 and forecasted rates for the remainder of the year.

Note 2 - A standby fee of 16 bps is charged on undrawn credit facility amounts, and has been reflected into the short term rate as if the forecast amount payable had been converted to a rate applied to commercial paper borrowings.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FEI's existing and forecast borrowing costs on long-term debt 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 2019 long-term debt schedule for FEI can be found in Section 11, Schedule 27.

FEI's Flow-through deferral account captures the variances in interest expense for return to or recovery from customers in the following year.

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 Rate for 2019 (which is equal to its after-tax weighted average cost of capital) is 5.66 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2019

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	2.67%	3.10%	2.26%	3.10%
Long Term Debt	58.83%	5.19%	3.79%	5.19%
Common Equity	38.50%	11.99%	8.75%	8.75%
Weighted Average	100.00%	7.75%	5.66%	6.50%

8.4 *SUMMARY*

FEI's equity financing and ROE have been forecast for 2019 at the same percentages as approved for 2018. FEI's debt financing costs on rate base are primarily determined by embedded rates on long-term debt and short-term debt; these rates are forecast to remain relatively stable.

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 2019, property taxes are forecast to increase by 0.6 percent from 2018 Approved, while income tax is forecast to increase by 1.9 percent compared to 2018 Approved. Any variances from the forecast of property taxes and income tax included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.2 PROPERTY TAXES

Property taxes for 2019 of $67.559 million 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)

Asset Type	Approved 2018	Projected 2018	Forecast 2019
Distribution Assets	$ 24.143	$ 23.162	$ 23.912
Transmission Assets	18.945	17.103	17.844
Gas Storage Assets	8.389	8.292	8.560
Manufactured Gas Assets	0.030	0.032	0.033
General Assets	4.499	4.382	4.606
In-Lieu	10.880	10.533	12.333
OGC Fees	0.290	0.285	0.290
Total Property Taxes	$ 67.176	$ 63.789	$ 67.578
Less: Property Tax Transferred to BVA	(0.019)	(0.019)	(0.019)
Net Property Tax Expense	67.157	63.770	67.559
Forecast Change from 2018 Approved			0.6%
Forecast Change from 2018 Projected			5.9%

As shown in the table above, in 2019 property taxes are forecast to increase by 0.6 percent from 2018 Approved and increase 5.9 percent compared to 2018 Projected. In general, the increase from 2018 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:

1. ***Changes in Tax Rates***. Tax Rates are expected to change on average as follows:
   a) Municipal rates are not expected to change;

   b) School rates are not expected to change;
   c) Rural rates are expected to decrease by 0.75 percent;
   d) Tax rates on First Nations are expected to increase 0.50 percent; and
   e) Other rates are expected to increase by 1.25 percent.

2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 17.1 percent based on actual revenues to be reported. The primary driver of the increase was the recovery of the commodity costs, which was generally higher in 2017 than in 2016. As 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.

3. ***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 1.4 percent increase in assessed values of distribution lines and services plus additional new construction;
   b. A 4.0 percent increase in assessed values of transmission lines;
   c. A 2.5 percent increase in assessed values for LNG assets; and
   d. Land value changes which are expected to range from a 3.0 percent increase in the assessed value for right of ways to a 5.0 percent increase in the 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 Commission approved past practice, at the corporate tax rate of 27 percent for 2019, which is unchanged from 2018. 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 2019 is forecast to increase by $0.966 million or 1.9 percent compared to 2018 Approved. This increase is primarily due to a higher delivery margin in 2019 offset by increase in O&M and interest expense.

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

9.4 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 has not yet come into force because the regulation by the Lieutenant Governor in Council required to proclaim this tax in force has not yet occurred. On March 22, 2018, the provincial government announced its intention to repeal this tax provided the LNG Canada project proponents conclusively decide to proceed with their projects on or before November 30, 2018. This would ensure this tax legislation and its application to FEI would be permanently deleted and would have to be re-enacted by the BC legislature in the future should a successor government wish to re-introduce this tax.

If it proceeds, the proposed LNG income tax would be a two-tier tax that applies a minimum 1.5 percent tax on LNG facilities' profits before recovery of capital investment costs and a 3.5 percent tax on LNG facilities' profits once payback is achieved (which increases to 5.0 per cent in 2037 and thereafter). This LNG income tax would apply to income earned at the existing Tilbury Facility, the Tilbury Expansion and the Mt. Hayes LNG Facility on Vancouver Island.

In conjunction with the LNG income tax legislation, the provincial government also proposed a Natural Gas Tax Credit (NGTC) against the current 11 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 8 percent.

Because the LNG income tax legislation is not in force and the provincial government announced that it intends to repeal this legislation should the LNG Canada project proponents make a conclusive decision to proceed by November 30, 2018, estimates of the LNG income tax and NGTC have not been included in forecast 2019 rates.

9.5 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 RIDES

10.1 *EARNINGS SHARING*

The PBR Decision (at page 124) stated that the inclusion of symmetric earnings sharing is beneficial to both FEI and its customers and approved an earnings sharing mechanism where gains and losses are shared equally between FEI and customers. For 2019, FEI is proposing to distribute a $1.466 million pre-tax credit ($1.070 million after tax) as shown in Table 10-1 below. This amount is composed of:

- 2018 projected sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth;
- The true-up of the 2017 projected earnings sharing to actual; and
- Financing on the deferral account balance.

Table 10-1: Summary of Earnings Sharing to be Returned in 2019 ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2018 Projected Sharing	(0.998)	Table 10-2, Line 51
2	2017 Actual Customer Growth adjustment	0.200	Table 10-3, Line 34
3	2017 Projected vs. Actual ending balance true-up	(0.192)	Table 10-4, Line 3
4	Financing	(0.080)	Table 10-5, Line 5
5			
6	**2019 after-tax amount returned to customers**	**(1.070)**	
7	**2019 pre-tax amount returned to customers**	**(1.466)**	Line 6 / 0.73

Each of these items is discussed in the sections below.

10.1.1 2018 Projected 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 Delivery 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[51] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[52]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

As discussed in Sections 1.4.1 and 1.4.4.1, FEI is projecting 2018 formula-driven O&M savings at $5.0 million, and 2018 capital expenditures in excess of the formula of $62.092 million. The $62.092 million excess 2018 capital expenditures will exceed the dead band by $54.145 million, such that FEI has removed the $54.145 million amount above the dead band in the calculation of 2018 earnings sharing, as shown in Line 33 of Table 10-2 below.

[51] Excluding items that are reforecast outside of the formula.
[52] Ibid.

Table 10-2: Calculation of 2018 Projected Earnings Sharing ($millions)

Line No.	Particulars							Reference
1	Approved Formula O&M	243.585						G-196-17
2								
3	Actual/Projected Gross O&M	270.212						
4	Less: O&M Tracked outside of Formula							
5	Pension/OPEB (O&M portion)	17.077						
6	Insurance	5.284						
7	Biomethane	1.929						
8	NGT O&M	1.660						
9	RS 16/46 O&M	6.506						
10	MSP	(0.829)						
11	Total	31.627						Sum of Lines 5 through 9
12								
13	Actual/Projected Base O&M	238.585						Line 3 - Line 11
14								
15	O&M Subject to Sharing	(5.000)						Line 13 - Line 1
16								
17			Annual Capital Expenditures					
18		Cumulative	2014	2015	2016	2017	2018	Note 1
19								
20	Formula CapEx	703.179	119.821	139.380	145.315	146.581	152.082	
21								
22	Total Regular CapEx	948.933	144.932	174.489	182.976	214.793	231.743	
23	Less: CapEx tracked outside of formula							
24	Pension and OPEB	18.104	3.915	4.324	4.075	2.663	3.127	
25	Biomethane	8.327	3.656	1.350	1.346	0.965	1.010	
26	NGT	23.713	5.816	5.607	5.797	2.134	4.359	
27	CIAC	30.669	4.419	6.336	6.309	6.880	6.725	
28	AFUDC	15.022	2.727	3.293	3.309	3.193	2.500	
29	MSP	(0.152)	-	-	-	-	(0.152)	
30	Total	95.684	20.533	20.911	20.836	15.835	17.569	Sum of Lines 24 through 28
31								
32	Actual/Projected Base CapEx	853.249	124.399	153.578	162.140	198.958	214.174	Line 22 - Line 30
33	Dead Band Adjustment	(100.953)		-	(9.176)	(37.632)	(54.145)	Adjustment to stay within deadband
34	Actual/Projected Base CapEx for ESM Calculation	752.296	124.399	153.578	152.964	161.326	160.029	Line 32 + Line 33
35								
36	Actual/Projected Cumulative Base CapEx Variance	49.117	4.578	14.198	7.649	14.745	7.947	Line 34 - Line 20
37								
38	Single Year Deadband % Variance (after adjustment)		3.70%	9.88%	5.12%	9.88%	5.12%	Line 36 / (Line 20 + Line 24)
39	Two year Cumulative Deadband % Variance (after adjustment)			13.58%	15.00%	15.00%	15.00%	Line 38 sum of two years
40								
41	Equity Component of Rate Base	38.5%						
42	Approved Return on Equity	8.75%						
43	After Tax Return on CapEx Subject to Sharing	1.655						Product of Lines 36, 41 & 42
44	Tax Rate	27.0%						
45								
46	Before Tax Return on CapEx Subject to Sharing	2.267						Line 43 / (1 - Line 44)
47								
48	Total before tax Sharing Amount	(2.733)						Line 15 + Line 46
49	Sharing percentage	50%						G-138-14
50								
51	2018 Projected Earnings Sharing (pre-tax)	(1.367)						Line 48 x Line 49
52	2018 Projected Earnings Sharing (after-tax)	(0.998)						Line 51 x 0.73

Notes

1 2014, 2015, 2016 and 2017 are actual results from BCUC Annual Report, 2018 is projected results

10.1.2 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.

FEI has calculated the resulting adjustment of $0.274 million debit ($0.200 million debit after-tax) for 2017 as shown in Table 10-3 below based on its actual customer additions.

Table 10-3: Calculation of Earnings Sharing Adjustment for Actual Customer Growth

Line No.	Particulars	$ millions	Reference
1	Average Customers 2017	997,380	
2	Average Customers 2016	983,807	
3	Growth in Average Customers	13,573	Line 1 - Line 2
4	Average Customer Growth	1.380%	Line 3 / Line 2
5		50%	G-138-14
6	Average Customer Growth to be recast in Formula	0.690%	Line 4 x Line 5
7	2017 Net Inflation Factor	0.320%	G-182-16 Compliance filing, Section 11, Schedule 3, Line 9, Column 6
8	2016 Reforecast Sustainment/Other Capital	$ 114.053	Note 1
9	2017 Reforecast Formulaic Sustainment/Other Capital	$ 115.207	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2017 Year Formulaic Sustainment/Other Capital	113.104	G-182-16 Compliance filing, Section 11, Schedule 4, Line 21, Column 3
11	Sustainment/Other Capital Increase from actual growth	$ 2.103	Line 9 - Line 10
12			
13			
14	Service Line Additions 2017	15,850	
15	Service Line Additions 2016	12,288	
16	Growth in Average Customers	3,562	Line 14 - Line 15
17	Average Customer Growth	28.99%	Line 16 / Line 15
18		50%	G-138-14
19	Average Customer Growth used in Formula	14.49%	Line 18 x Line 17
20	2016 Reforecast Service Line Additions	11,551	2018 Annual Review of Rates Table 10-3, Line 21
21	2017 ReForecast Service Line Additions	13,225	Line 20 x (1 + Line 19)
22	Service Line Addition Cost per Customer ($)	2,994	
23	2017 Reforecast Formulaic Growth Capital	$ 39.602	Line 21 x Line 22 / 1000000
24	2017 Formulaic Growth Capital	33.477	G-182-16 Compliance filing, Section 11, Schedule 4, Line 21, Column 2
25	Growth Capital Increase from actual growth	$ 6.125	Line 23 - Line 24
26			
27			
28	Increase in Capital Requirements from Actual Growth	$ 8.228	Line 11 + Line 25
29	Mid Year	$ 4.114	Line 28 / 2
30			
31	Equity Cost Component	3.37%	G-182-16
32	Debt Cost Component	3.29%	G-182-16
33	Earned Return on incremental Capital Requirements (pre-tax)	$ 0.274	Line 29 x (Line 31 + Line 32)
34	Earned Return on incremental Capital Requirements (after-tax)	$ 0.200	Line 33 x 0.73

Notes

1 2018 Annual Review for Rates Table 10-3, Line 9

10.1.3 True-Up for 2017 Actual Earnings Sharing

In FEI's 2017 Annual Report to the Commission, FEI calculated the final 2017 earnings sharing based on the final 2017 results. The final amount of earnings sharing for 2017 was $2.683 million, which was $0.192 million higher than the $2.491 million projected for 2017, as shown in Table 10-4 below. As a result, FEI is a sharing by the after-tax amount of $0.192 million as shown in Table 10-1 above.

Table 10-4: Calculation of 2017 Actual Earnings Sharing true-up ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2017 Actual Earnings Sharing account ending balance	(2.683)	2017 FEI BCUC Annual Report
2	2017 Projected Earnings Sharing account ending balance	(2.491)	Annual Review of 2018 Rates Compliance Filing financial schedules, Schedule 12, Line 20, Column 2
3	**2017 Earnings Sharing account true-up**	**(0.192)**	

10.1.4 Financing

FEI has calculated the financing on the deferral account balances that result from the amounts described above. As the balances are positive, financing consists of credits to customers at FEI's WACC. As shown in Table 10-5 below, FEI has calculated a $0.041 million credit to true-up for 2018 projected financing and a forecast $0.039 million credit for 2019 financing. This results in a total after-tax financing adjustment of $0.080 million to be distributed to customers as shown in Table 10-1 above.

Table 10-5: Calculation of Earnings Sharing financing ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2018 Projected Earnings Sharing financing	(0.112)	
2	Less: 2018 Forecasted Earnings Sharing financing	(0.071)	Annual Review of 2018 Rates Compliance Filing financial schedules, Schedule 12, Line 20, Column 4
3	2018 Earnings Sharing financing true-up	(0.041)	
4	Add: 2019 Forecasted Earnings Sharing financing	(0.039)	Section 11, Schedule 12, Line 19, Column 4
5	**2018/2019 Financing Adjustments**	**(0.080)**	

10.1.5 Summary of Earnings Sharing

After calculating the 2018 projected earnings sharing and including the adjustments described above, FEI proposes to distribute $1.466 million to customers in 2019 as a reduction in 2019 revenue requirements through amortization of the projected 2019 opening after-tax balance of $1.070 million in the Earnings Sharing deferral account.

As part of the future rate filings, the earnings sharing for 2018 will be subject to similar true-ups as described above which account for the actual O&M and capital expenditure amounts for 2018, as well as impacts, if any, associated with non-performance of Service Quality Metrics, based on final 2018 results.

10.2 *RATE RIDERS*

There are two delivery rate riders that are set this year through the annual review process. These are the BVA Rate Rider and the RSAM Rate Riders.

10.2.1 BVA Rate Rider

On August 12, 2016, the Commission 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 closing 2018 balance of the BVA Rate Rider Account, and the calculation of the BVA Rate Riders for 2019.

10.2.1.1 BVA Rate Rider Account

The cumulative BVA Rate Rider Account balance at the end of December 31, 2018 is projected to be a debit of $3.607 million before-tax. This balance consists of the prior year actual 2017 true-up and BVA Rider recovery shortfall of $0.382 million after-tax, and a projected 2018 after-tax addition of $2.251 million transferred from the BVA, and grossed up for the current tax rate of 27 percent[53].

[53] $0.382 million + $2.251 million = $2.633 million divided by (1 – 0.27) = $3.607 million

Table 10-6: BVA Rate Rider Account

Line No	BVA Continuity		2018 Projected (a) ($000s)
1	**BVA Opening Balance**	(b)	
2	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		(471.3)
3	Pre-Tax Adjustment for Unsold Biomethane at January 1,	(c)	471.3
4	Pre-Tax Adjustment for Unsold Biomethane		$ -
5			
6	Tax Recovery	27%	-
7	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ -
8			
9	**BVA BVA Activities:**		
10	Biomethane Costs Incurred		$ 6,520.7
11	Biomethane Costs Recovered		(3,436.8)
12	Change in Unsold Biomethane Quantity		-
13	Total Activities - Pre-Tax		$ 3,084.0
14			
15	**BVA Ending Balance at December 31,**		
16	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		
17	Line 10 + Line 11		$ 3,084.0
18	Pre-Tax Adjustment for Unsold Biomethane at December 31,		
19	Line 12	(d)	-
20	Pre-Tax Balance After Adjustment for Unsold Biomethane)		**$ 3,084.0**
21			
22	Tax Recovery	27%	(832.7)
23			
24	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ 2,251.3
25			
26	**Transfer to BVA Rate Rider Account**	(e)	**$ (2,251.3)**
27			
28	Net of Tax Balance (After transfer to BVA Rider Account)		$ -

Notes

(a) The annual forecast is the current 2018 forecast provided in this 2019 PBR Annual Review

(b) Recorded opening balance reconciles to the December 31, 2017 balance in the FortisBC Energy Inc. 2017 BVA Status Report filed April 30, 2018.

(c)

Calculation of Adjustment for Unsold Biomethane at December 31, 2017	2017 Recorded	2018 Projected
December 31, 2016 Quantity Unsold (in TJ)	32.4	(46.9)
December 31, 2017 Quantity Unsold (in TJ) adjustment	-	(1.4)
Carbon Offset Purchased (TJ) for Dec 31, 2017 shortfall	-	48.3
2017 Quantity Purchased (in TJ)	153.8	342.3
2017 Quantity Sold (in TJ)	(233.1)	(342.3)
Total Quantity Unsold at December 31, 2017 (in TJ)	(46.9)	0.0
BERC rate in effect at forecast (in $/GJ)		
January 1, 2018 effective BERC rate (in $/GJ)	$ 10.039	$ 10.039
Value of Unsold Biomethane at December 31, 2017	$ (471.3)	$ 0.0

(d) The Dec 31, 2018 inventory is forecast at 0.0 TJ, and therefore no unsold biomethane inventory remain. Carbon Offset purchases where made during 2018 to cover the opening balance shortfall and current year activity

(e) Pursuant to Order G-133-16, and the Decision issued concurrently, the net of tax balance at December 31, 2018, 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

As discussed in section 10.2.1.1 above, the cumulative BVA Rate Rider for recovery in 2019 is forecast at $3.607 million before-tax and is recovered from non-bypass customers based on forecast 2019 volumes. In order to calculate a BVA Rate Rider, the projected BVA Rate Rider Account balance of $3.607 million is divided by the forecast 2019 non-bypass volumes of 201,573 TJ, for a BVA Rate Rider of $0.018 cents per GJ. Any difference between the actual and forecast BVA Rider collected will be trued up in the subsequent year. Details of the BVA Rate Rider calculation are provided in Table 10-7 below.

Table 10-7: 2019 BVA Rate Rider Calculation

Line No	Particulars	($000s)	BVA Rider Rider Projected 2019 ($000s)	Non-Bypass Forecast 2019 Vol (TJ)
1	**Transfers From BVA to BVA Rider Account**	Net of Tax	Grossed Up	
2	Net-Tax Balance Dec 31, 2016 Actual (Grossed up for tax)	2,202.9	$ 2,976.9	
3	Net-Tax Dec 31, 2017 Projected (Grossed up for tax)	1,627.2	2,198.9	
4		3,830.1	5,175.8	
5	**Adjustment On Prior Year forecast**			
6	Net-Tax Dec 31, 2017 Actual (Grossed up for tax)	1,866.3	2,522.0	
7	Net-Tax Dec 31, 2017 Projected (Grossed up for tax) Prior year	(1,627.2)	(2,198.9)	
8	True - Up adjustment for 2017	239.1	323.1	
9	True - Up adjustment for 2017 increase in tax rate	-	75.3	
10	Adjusted closing BVA Rider balance at Dec 31, 2017	4,069.2	5,574.3	
11	Less Projected 2018 BVA Rider recoveries for 2017 using 2018 Projected Non-bypass volumes	(3,687.3)	(5,051.1)	
12	Projected BVA Rider Shortfall Dec 31, 2018 for 2017	381.94	523.2	
13				
14	**Net-Tax Dec 31, 2018 Projected Transfer into Rider account** (Grossed up for tax)	2,251.3	$ 3,084.0	
15				
16	**Total BVA Rider to be collected in 2019**	**2,633.2**	**3,607.2**	**201,573.0**
17				
18	**BVA Rider by Rate class - (Non - Bypass)**			
19				
20	**Residential**			
21	Rate Schedule 1		$ 1,445.4	80,768.4
22	**Commercial**			
23	Rate Schedule 2		$ 540.6	30,209.8
24	Rate Schedule 3		$ 385.6	21,546.4
25	Rate Schedule 23		$ 171.0	9,557.9
26	**Industrial**			
27	Rate Schedule 4		$ 2.5	141.3
28	Rate Schedule 5		$ 56.0	3,129.4
29	Rate Schedule 6		$ 0.7	41.0
30	Rate Schedule 7		$ 5.7	316.1
31	Rate Schedule 22- Firm Service		$ 203.0	11,343.9
32	Rate Schedule 22- Interruptible Service		$ 394.3	22,036.2
33	Rate Schedule 25		$ 261.2	14,594.9
34	Rate Schedule 27		$ 141.2	7,887.7
35				
36	**Total BVA Rider (Non-Bypass)**		**$ 3,607.2**	**201,573.0**
37				
38	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.018**	
39	(Line 16 divided by Line 25 TJ) $3,607.2/201,573.0 TJ = $0.018 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 2018 the projected recoveries are $3.437 million attributable to sales volumes of 342.2 TJ from 10,578 RNG customers. The expected sales volume from existing and projected long-term contracts is included in the 2018 projected volume and revenue in Table 10-8.

Table 10-8: BERC Revenue and Volume

Line No	Volume and Revenue	2017 Actual	2017 Projected	2017 Variance	2018 Projected
1	**Volume (TJ)**				
2	**Short-term**				
3	Rate Schedule 1B	88.4	84.9	3.5	103.5
4	Rate Schedule 2B	13.2	10.9	2.3	15.8
5	Rate Schedule 3B	16.2	8.1	8.2	22.3
6	Rate Schedule 5B	-	-	-	-
7	Rate Schedule 11B	98.7	80.6	18.1	53.7
8	Rate Schedule 30	-	-	-	-
9	Sub-total	216.5	184.4	32.1	195.3
10					
11	**Long Term (a)**				
12	Rate Schedule 11B	16.6	35.5	(18.9)	146.9
13	Sub-total	16.6	35.5	-	146.9
14					
15	**Total Sales Volume (TJ)**	233.1	219.9	13.2	342.2
16					
17	**Recoveries ($000s)**				
18	**Short-term**				
19	Rate Schedule 1B	$ 931.5	$ 894.5	$ 37.0	$ 1,039.7
20	Rate Schedule 2B	138.8	114.7	24.1	158.6
21	Rate Schedule 3B	171.2	85.2	86.1	223.6
22	Rate Schedule 5B	-	-	-	-
23	Rate Schedule 11B	1,040.2	849.6	190.6	539.6
24	Rate Schedule 30	3.5	3.5	(0.0)	-
25	Sub-total	2,285.3	1,947.6	337.7	1,961.5
26					
27	**Long Term (a)**				
28	Rate Schedule 11B	166.0	374.1	(208.2)	1,475.2
29	Sub-total	166.0	374.1	(208.2)	1,475.2
30				-	
31	**Total Sales**	$ 2,451.2	$ 2,321.7	$ 129.6	$ 3,436.7

In the 2016 Biomethane Decision, FEI was also directed to provide the number of customers by rate class. The following table sets out the 2018 Projected number of renewable natural gas customers by rate class.

Table 10-9: RNG Customers by Rate Schedule

2018 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short-term	
Rate Schedule 1B	10,358
Rate Schedule 2B	197
Rate Schedule 3B	14
Rate Schedule 11B	6
Rate Schedule 5B	-
Rate Schedule 30 Off System	-
Long-term	
Rate Schedule 11B	3
Total	10,578

In summary, the 2019 BVA Rate Rider attributable to the cumulative December 31, 2018 transfers from the BVA is $0.018 cents 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 2018 is a credit of $9.300 million. The calculation of the 2019 RSAM riders is shown in Table 10-10.

Table 10-10: 2019 RSAM Riders

2018 RSAM + Interest Closing Balance ($000)	(9,300)
Amortization Period (Years)	2
2019 Amortization Post-Tax ($000)	(4,650)
Tax Rate	27%
2019 Amortization Pre-Tax ($000)	(6,370)

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization ($000)	2019 Volume (TJ)	Rider ($/GJ)
Rate 1/1B/1U/1X		80,768.4	(0.045)
Rate 2/2B/2U/2X		30,209.8	(0.045)
Rate 3/3B/3U/3X		21,546.4	(0.045)
Rate 23		9,557.9	(0.045)
	(6,370)	142,082.5	(0.045)

The differences that result from the actual 2018 ending RSAM balance varying from the projection, and the actual 2019 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2020 RSAM Rate Riders and, in this way, refunded to or collected from customers.

10.3 *SUMMARY*

FEI has calculated the amount of earnings sharing to be returned to customers in 2019 in compliance with the approved mechanism, including an estimate for 2018 which includes an adjustment for capital exceeding the dead band, a true-up for 2017, and an adjustment for the impact of actual customer additions on growth capital. In addition, FEI has updated all of the 2019 delivery rate riders for 2018 projected ending balances and 2019 forecast volumes.

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
FOR THE YEAR ENDING DECEMBER 31, 2019
($millions)

Line No.	Particulars	2019 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (14.185)		
3	Change in Other Revenue	(0.172)	(14.357)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	5.254		
7	Capitalized Overhead Change	(0.660)	4.594	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		9.281	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.193)		
14	Deferrals	(2.041)	(2.234)	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	(0.647)		
18	Financing Ratio Changes	3.271		
19	Rate Base Growth	7.197	9.821	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	0.402		
23	Other Income Taxes Changes	0.966	1.368	
24				
25	**Amortization of 2017/18 Surplus**		(3.075)	
26				
27	**2018 REVENUE SURPLUS**		(5.398)	
28				
29	Revenue Deficiency (Surplus)		$ 0.000	Schedule 16, Line 11, Column 4
30				
31	Non-Bypass Margin @ Existing Rates		806.216	Schedule 19, Line 17, Column 3
32	Rate Change		0.00%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 5,831,382	$ 6,193,927	$ 362,545	Schedule 6.2, Line 34, Column 3
2	Opening Balance Adjustment	27,640	56,533	28,893	Schedule 6.2, Line 34, Column 4
3	Net Additions	787,647	708,707	(78,940)	Schedule 6.2, Line 34, Column 5+6+7
4	Plant in Service, Ending	6,646,669	6,959,167	312,498	
5					
6	Accumulated Depreciation Beginning	$ (1,931,842)	$ (2,066,879)	$ (135,037)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(134,438)	(155,489)	(21,051)	Schedule 7.2, Line 35, Column 7+8
9	Accumulated Depreciation Ending	(2,066,280)	(2,222,368)	(156,088)	
10					
11	CIAC, Beginning	$ (427,702)	$ (435,028)	$ (7,326)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	(1,167)	(2,387)	(1,220)	Schedule 9, Line 6, Column 3
13	Net Additions	(5,667)	(5,812)	(145)	Schedule 9, Line 6, Column 5+6
14	CIAC, Ending	(434,536)	(443,227)	(8,691)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 153,822	$ 162,663	$ 8,841	Schedule 9, Line 13, Column 2
17	Net Additions	8,828	9,021	193	Schedule 9, Line 13, Column 5+6
18	Accumulated Amortization Ending - CIAC	162,650	171,684	9,034	
19					
20	Net Plant in Service, Mid-Year	$ 3,980,318	$ 4,187,043	$ 206,725	
21					
22	Adjustment for timing of Capital additions	$ 319,444	$ 269,916	$ (49,528)	
23	Capital Work in Progress, No AFUDC	34,392	43,820	9,428	
24	Unamortized Deferred Charges	(16,221)	(55,479)	(39,258)	Schedule 11.1, Line 22, Column 10
25	Working Capital	52,998	35,899	(17,099)	Schedule 13, Line 14, Column 3
26	Deferred Income Taxes Regulatory Asset	435,603	465,388	29,785	Schedule 15, Line 6, Column 3
27	Deferred Income Taxes Regulatory Liability	(435,603)	(465,388)	(29,785)	Schedule 15, Line 6, Column 3
28	LILO Benefit	(328)	(195)	133	
29					
30	Mid-Year Utility Rate Base	$ 4,370,603	$ 4,481,004	$ 110,401	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	Reference	2014	2015	2016	2017	2018	2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Formula Cost Drivers**								
2	CPI		0.473%	0.879%	0.980%	1.627%	1.979%	2.345%	
3	AWE		2.277%	1.646%	2.050%	1.250%	1.473%	2.635%	
4	Labour Split								
5	Non Labour		45.000%	45.000%	45.000%	45.000%	45.000%	45.000%	
6	Labour		55.000%	55.000%	55.000%	55.000%	55.000%	55.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	1.460%	1.301%	1.569%	1.420%	1.701%	2.505%	
8	Productivity Factor		-1.100%	-1.100%	-1.100%	-1.100%	-1.100%	-1.100%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.360%	0.201%	0.469%	0.320%	0.601%	1.405%	
10									
11	Customer Growth Factor		0.260%	0.614%	0.567%	0.675%	0.715%	0.776%	
12	Inflation Factor for Base Capital	(1 + Line 9) x (1 + Line 11)	100.621%	100.816%	101.039%	100.997%	101.320%	102.192%	
13									
14	Service Line Additions Factor		-0.688%	-5.615%	16.249%	0.324%	11.302%	5.600%	
15	Inflation Factor for Growth Capital	(1 + Line 9) x (1 + Line 14)	99.669%	94.575%	116.794%	100.645%	111.971%	107.084%	

CAPITAL EXPENDITURES Schedule 4
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**2013**					
2	Base	$ 21,881	$ 99,243			
3	**2014**					
4	Net Inflation Factor	99.669%	100.621%			Schedule 3, Line 12 & 15, Column 3
5	FEI Formula Capex	21,809	99,859			
6	Reclassify Pension & OPEB from Formula	(331)	(1,516)			
7	FEI Net Formula Capex	21,478	98,343			
8	FEVI Capex	8,378	11,518			Note 1
9	FEW Capex	258	142			
10	Total	30,114	110,003			
11	**2015**					
12	Net Inflation Factor	94.575%	100.816%			Schedule 3, Line 12 & 15, Column 4
13	Formula Capex	28,479	110,901			
14	**2016**					
15	Net Inflation Factor	116.794%	101.039%			Schedule 3, Line 12 & 15, Column 5
16	Formula Capex	33,262	112,053			
17	Less: Fort Nelson Intangible Plant	-	(66)			
18	Total	33,262	111,987			
19	**2017**					
20	Net Inflation Factor	100.645%	100.997%			Schedule 3, Line 12 & 15, Column 6
21	Formula Capex	$ 33,477	$ 113,104			
22	**2018**					
23	Net Inflation Factor	111.971%	101.320%			Schedule 3, Line 12 & 15, Column 7
24	Formula Capex	$ 37,485	$ 114,597			
25	**2019**					
26	Net Inflation Factor	107.084%	102.192%			Schedule 3, Line 12 & 15, Column 8
27	Formula Capex	$ 40,140	$ 117,109		$ 157,249	
28						
29	**Capital Tracked Outside of Formula**					
30	Pension & OPEB (Capital Portion)			$ 3,565		
31	Biomethane Upgraders			11,300		
32	Biomethane Interconnect			1,561		
33	NGT Assets			8,455		
34	Employer Health Tax			481		
35	MSP			(152)		
36	Total			$ 25,210	25,210	
37						
38	**Total Capital Expenditures Net of CIAC**				$ 182,459	
39						
40	Contributions in Aid of Construction				5,812	
41	System Extension Fund				1,000	
42						
43	**Total Regular Capital Expenditures to Plant**				$ 189,271	
44						
45	Notes					
46	1. FEVI growth capex of $8,802 thousand less $424 thousand of pension and OPEBs; FEVI other capex of $13,908 thousand less $2,390 thousand of pension and OPEBs.					

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 5

Line No.	Particulars (1)	2019 Formula (2)	Cross Reference (3)
1	**CAPEX**		
2			
3	Growth Capital Expenditures	$ 40,140	Schedule 4, Line 27, Column 2
4	Sustainment Capital Expenditures	117,109	Schedule 4, Line 27, Column 3
5	Forecast Capital Expenditures	25,210	Schedule 4, Line 36, Column 4
6	CIAC (Net of System Extension Fund)	6,812	Schedule 4, Lines 40 + 41, Column 5
7	Total Capital Expenditures	$ 189,271	
8			
9	**Special Projects and CPCN's**		
10			
11	LMIPSU	$ 171,642	
12	Total Capital Expenditures	$ 171,642	
13			
14	**Total Capital Expenditures**	$ 360,913	
15			
16			
17	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**		
18			
19	Regular Capital Expenditures	$ 189,271	Line 7
20	Add - Capitalized Overheads	33,736	Schedule 20, Line 43, Column 4
21	Add - AFUDC	2,912	
22	Gross Capital Expenditures	225,919	
23	Change in Work in Progress	(11,711)	
24	**Total Regular Additions to Plant**	$ 214,208	
25			
26	Special Projects and CPCN's Capital Expenditures	$ 171,642	Line 12
27	Add - AFUDC	15,258	
28	Gross Capital Expenditures	186,900	
29	Change in Work in Progress	352,931	
30	**Total Special Projects and CPCN Additions to Plant**	$ 539,831	
31			
32	**Grand Total Additions to Plant**	$ 754,039	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	12/31/2018	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2019	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	-	-	4,296	-	-	4,296	
9	461-01	Transmission Land Rights	56,110	171	-	515	-	56,796	
10	461-02	Transmission Land Rights - Mt. Hayes	610	-	-	-	-	610	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	87	-	-	-	-	87	
13	471-01	Distribution Land Rights	3,079	-	-	-	-	3,079	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	112,689	2,519	-	7,465	(6,898)	115,775	
16	402-02	Application Software - 20%	33,265	2,223	-	6,433	(2,215)	39,706	
17			$ 209,737	$ 4,913	$ 4,296	$ 14,413	$ (9,113)	$ 224,246	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	998	-	-	-	-	998	
22	433-00	Manufact'd Gas - Equipment	2,239	91	-	364	-	2,694	
23	434-00	Manufact'd Gas - Gas Holders	2,940	-	-	-	-	2,940	
24	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	-	-	-	-	875	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	4,959	-	97,565	-	-	102,524	
28	443-00	Gas Holders - Storage (Tilbury)	16,499	-	69,689	-	-	86,188	
29	448-11	Piping (Tilbury)	-	-	60,397	-	-	60,397	
30	448-21	Pre-treatment (Tilbury)	-	-	46,459	-	-	46,459	
31	448-31	Liquefaction Equipment (Tilbury)	-	-	125,440	-	-	125,440	
32	449-00	Local Storage Equipment (Tilbury)	37,859	675	-	2,593	(21)	41,106	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	17,310	-	-	-	-	17,310	
35	443-05	Gas Holders - Storage (Mount Hayes)	60,112	-	-	-	-	60,112	
36	448-41	Send out Equipment(Tilbury)	-	-	4,646	-	-	4,646	
37	448-51	Sub-station and Electric (Tilbury)	-	-	41,813	-	-	41,813	
38	448-61	Control Room (Tilbury)	-	-	13,938	-	-	13,938	
39	448-10	Piping (Mount Hayes)	11,488	-	-	-	-	11,488	
40	448-20	Pre-treatment (Mount Hayes)	28,714	-	-	-	-	28,714	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,714	-	-	-	-	28,714	
42	448-40	Send out Equipment (Mount Hayes)	22,960	-	-	-	-	22,960	
43	448-50	Sub-station and Electric (Mount Hayes)	21,644	-	-	-	-	21,644	
44	448-60	Control Room (Mount Hayes)	5,900	-	-	-	-	5,900	
45	449-01	Local Storage Equipment (Mount Hayes)	6,363	-	-	-	-	6,363	
46			$ 286,219	$ 766	$ 459,947	$ 2,957	$ (21)	$ 749,868	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	12/31/2018	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,627	$ -	$ -	$ -	$ -	$ 10,627	
3	461-00	Transmission Land Rights	1	-	-	-	-	1	
4	462-00	Compressor Structures	29,484	-	-	-	-	29,484	
5	463-00	Measuring Structures	14,018	-	-	-	-	14,018	
6	464-00	Other Structures & Improvements	6,485	-	-	-	-	6,485	
7	465-00	Mains	1,374,752	3,997	-	15,546	(1,401)	1,392,894	
8	465-20	Mains - INSPECTION	21,928	693	-	2,740	(3,637)	21,724	
9	465-11	IP Transmission Pipeline - Whistler	42,288	-	-	-	-	42,288	
10	465-30	Mt Hayes - Mains	6,299	-	-	-	-	6,299	
11	465-10	Mains - Byron Creek	974	-	-	-	-	974	
12	466-00	Compressor Equipment	186,114	761	-	3,010	(753)	189,132	
13	466-10	Compressor Equipment - OVERHAUL	3,676	-	-	-	(1,571)	2,105	
14	467-30	Mt. Hayes - Measuring and Regulating Equipment	5,342	-	-	-	-	5,342	
15	467-10	Measuring & Regulating Equipment	54,759	-	4,646	-	-	59,405	
16	467-20	Telemetering	14,993	96	-	362	(8)	15,443	
17	467-31	IP Intermediate Pressure Whistler	313	-	-	-	-	313	
18	467-30	Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	39	
19	468-00	Communication Structures & Equipment	3,795	-	-	-	-	3,795	
20			$ 1,775,887	$ 5,547	$ 4,646	$ 21,658	$ (7,370)	$ 1,800,368	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 4,207	$ -	$ -	$ -	$ -	$ 4,207	
24	472-00	Structures & Improvements	21,577	-	9,432	-	-	31,009	
25	472-10	Structures & Improvements - Byron Creek	107	-	-	-	-	107	
26	473-00	Services	1,202,499	12,430	-	51,563	(3,931)	1,262,561	
27	474-00	House Regulators & Meter Installations	174,221	-	-	-	(5,271)	168,950	
28	474-02	Meters/Regulators Installations	187,770	7,466	-	28,227	-	223,463	
29	475-00	Mains	1,430,784	8,216	59,152	32,422	(1,944)	1,528,630	
30	476-00	Compressor Equipment	1,110	-	-	-	-	1,110	
31	477-10	Measuring & Regulating Equipment	151,051	2,506	2,358	9,904	(571)	165,248	
32	477-20	Telemetering	13,765	281	-	1,096	(64)	15,078	
33	477-30	Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	163	
34	478-10	Meters	274,178	5,031	-	14,633	(3,512)	290,330	
35	478-20	Instruments	11,944	-	-	-	-	11,944	
36			$ 3,473,376	$ 35,930	$ 70,942	$ 137,845	$ (15,293)	$ 3,702,800	
37									
38		**BIO GAS**							
39	472-00	Bio Gas Struct. & Improvements	$ 661	$ -	$ -	$ 149	$ -	$ 810	
40	475-10	Bio Gas Mains – Municipal Land	1,622	-	-	580	-	2,202	
41	475-20	Bio Gas Mains – Private Land	55	-	-	-	-	55	
42	418-10	Bio Gas Purification Overhaul	20	-	-	-	-	20	
43	418-20	Bio Gas Purification Upgrader	9,897	-	-	-	-	9,897	
44	477-40	Bio Gas Reg & Meter Equipment	2,600	-	-	844	-	3,444	
45	478-30	Bio Gas Meters	36	-	-	15	-	51	
46	474-10	Bio Gas Reg & Meter Installations	226	-	-	7	-	233	
47	483-25	RNG Comp S/W	-	-	-	-	-	-	
48			$ 15,117	$ -	$ -	$ 1,595	$ -	$ 16,712	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	12/31/2018	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 15,616	$ -	$ -	$ 5,092	$ -	$ 20,708	
3	476-20	NG Transportation LNG Dispensing Equipment	13,412	-	-	3,537	-	16,949	
4	476-30	NG Transportation CNG Foundations	2,365	-	-	-	-	2,365	
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	488	-	-	-	-	488	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 34,686	$ -	$ -	$ 8,629	$ -	$ 43,315	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 33,309	$ 140	$ -	$ 402	$ -	$ 33,851	
13	482-10	Frame Buildings	18,123	-	-	-	-	18,123	
14	482-20	Masonry Buildings	138,206	2,167	-	6,247	(160)	146,460	
15	482-30	Leasehold Improvement	5,176	71	-	207	(100)	5,354	
16	483-30	GP Office Equipment	5,374	208	-	603	(338)	5,847	
17	483-40	GP Furniture	24,368	703	-	2,021	(353)	26,739	
18	483-10	GP Computer Hardware	50,558	3,426	-	9,944	(8,373)	55,555	
19	483-20	GP Computer Software	3,787	-	-	-	(1,440)	2,347	
20	484-00	Vehicles	20,893	974	-	2,800	-	24,667	
21	484-10	Vehicles - Leased	23,255	-	-	-	(1,458)	21,797	
22	485-10	Heavy Work Equipment	858	-	-	-	-	858	
23	485-20	Heavy Mobile Equipment	5,857	-	-	-	-	5,857	
24	486-00	Small Tools & Equipment	54,549	1,244	-	3,576	(1,044)	58,325	
25	487-20	Equipment on Customer's Premises	12	-	-	-	(9)	3	
26	488-10	Telephone	2,905	-	-	-	(260)	2,645	
27	488-20	Radio	11,675	444	-	1,311	-	13,430	
28			$ 398,905	$ 9,377	$ -	$ 27,111	$ (13,535)	$ 421,858	
29									
30		**UNCLASSIFIED PLANT**							
31	499-00	Plant Suspense	-	-	-	-	-	-	
32			$ -	$ -	$ -	$ -	$ -	$ -	
33									
34		**Total Plant in Service**	$ 6,193,927	$ 56,533	$ 539,831	$ 214,208	$ (45,332)	$ 6,959,167	
35									
36		Cross Reference			Schedule 5, Line 30, Column 2	Schedule 5, Line 24, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2018	1/1/2019 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2019	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%	$ 61	$ -	$ 1	$ -	$ -	$ -	$ 62	
3	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	777	-	-	-	-	-	777	
4	178-00	Organization Expense	728	1.00%	436	-	7	-	-	-	443	
5	401-01	Franchise and Consents	297	5.39%	215	-	11	-	-	-	226	
6	402-11	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	-	62	
7	402-03	Other Intangible Plant	1,907	2.01%	1,108	-	38	-	-	-	1,146	
8	440-02	Water/Land Rights Tilbury	4,296	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	56,281	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	610	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	87	0.00%	10	-	-	-	-	-	10	
13	471-01	Distribution Land Rights	3,079	0.00%	238	-	-	-	-	-	238	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	115,208	12.50%	73,518	-	14,401	(6,898)	-	-	81,021	
16	402-02	Application Software - 20%	35,488	20.00%	14,742	-	7,098	(2,215)	-	-	19,625	
17			$ 218,946		$ 92,953	$ -	$ 21,556	$ (9,113)	$ -	$ -	$ 105,396	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	998	2.82%	344	-	28	-	-	-	372	
22	433-00	Manufact'd Gas - Equipment	2,330	4.66%	426	-	104	-	-	-	530	
23	434-00	Manufact'd Gas - Gas Holders	2,940	2.45%	656	-	72	-	-	-	728	
24	436-00	Manufact'd Gas - Compressor Equipment	367	3.68%	140	-	13	-	-	-	153	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	2.34%	947	-	20	-	-	-	967	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	102,524	3.03%	3,797	-	3,106	-	-	-	6,903	
28	443-00	Gas Holders - Storage (Tilbury)	86,188	1.88%	12,615	-	1,620	-	-	-	14,235	
29	448-11	Piping (Tilbury)	60,397	2.46%	-	-	1,486	-	-	-	1,486	
30	448-21	Pre-treatment (Tilbury)	46,459	3.88%	-	-	1,803	-	-	-	1,803	
31	448-31	Liquefaction Equipment (Tilbury)	125,440	2.46%	-	-	3,086	-	-	-	3,086	
32	449-00	Local Storage Equipment (Tilbury)	38,534	3.83%	17,975	-	1,450	(21)	-	-	19,404	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	17,310	3.88%	5,203	-	672	-	-	-	5,875	
35	443-05	Gas Holders - Storage (Mount Hayes)	60,112	1.65%	7,587	-	992	-	-	-	8,579	
36	448-41	Send out Equipment(Tilbury)	4,646	2.44%	-	-	113	-	-	-	113	
37	448-51	Sub-station and Electric (Tilbury)	41,813	2.44%	-	-	1,020	-	-	-	1,020	
38	448-61	Control Room (Tilbury)	13,938	6.30%	-	-	878	-	-	-	878	
39	448-10	Piping (Mount Hayes)	11,488	2.46%	2,169	-	283	-	-	-	2,452	
40	448-20	Pre-treatment (Mount Hayes)	28,714	3.88%	8,639	-	1,114	-	-	-	9,753	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,714	2.46%	5,419	-	706	-	-	-	6,125	
42	448-40	Send out Equipment (Mount Hayes)	22,960	2.44%	4,324	-	560	-	-	-	4,884	
43	448-50	Sub-station and Electric (Mount Hayes)	21,644	2.44%	4,076	-	528	-	-	-	4,604	
44	448-60	Control Room (Mount Hayes)	5,900	6.30%	2,941	-	372	-	-	-	3,313	
45	449-01	Local Storage Equipment (Mount Hayes)	6,363	2.86%	563	-	182	-	-	-	745	
46			$ 746,932		$ 77,822	$ -	$ 20,208	$ (21)	$ -	$ -	$ 98,009	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2018	1/1/2019 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,627	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	1	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	29,484	3.51%	17,681	-	1,035	-	-	-	18,716	
5	463-00	Measuring Structures	14,018	2.29%	7,413	-	321	-	-	-	7,734	
6	464-00	Other Structures & Improvements	6,485	3.66%	3,121	-	237	-	-	-	3,358	
7	465-00	Mains	1,378,749	1.47%	412,254	-	20,209	(1,401)	-	-	431,062	
8	465-20	Mains - INSPECTION	22,621	15.20%	11,994	-	3,333	(3,637)	-	-	11,690	
9	465-11	IP Transmission Pipeline - Whistler	42,288	1.53%	5,781	-	647	-	-	-	6,428	
10	465-30	Mt Hayes - Mains	6,299	1.51%	788	-	95	-	-	-	883	
11	465-10	Mains - Byron Creek	974	5.03%	1,280	-	49	-	-	-	1,329	
12	466-00	Compressor Equipment	186,875	2.89%	91,813	-	5,379	(753)	-	-	96,439	
13	466-10	Compressor Equipment - OVERHAUL	3,676	10.19%	3,269	-	375	(1,571)	-	-	2,073	
14	467-30	Mt. Hayes - Measuring and Regulating Equipment	5,342	2.58%	1,452	-	138	-	-	-	1,590	
15	467-10	Measuring & Regulating Equipment	59,405	2.41%	26,357	-	1,432	-	-	-	27,789	
16	467-20	Telemetering	15,089	9.75%	9,434	-	1,462	(8)	-	-	10,888	
17	467-31	IP Intermediate Pressure Whistler	313	2.55%	105	-	8	-	-	-	113	
18	467-30	Measuring & Regulating Equipment - Byron Creek	39	2.41%	12	-	1	-	-	-	13	
19	468-00	Communication Structures & Equipment	3,795	0.56%	4,401	-	21	-	-	-	4,422	
20			$ 1,786,080		$ 597,658	$ -	$ 34,742	$ (7,370)	$ -	$ -	$ 625,030	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 4,207	0.00%	$ (9)	$ -	$ -	$ -	$ -	$ -	$ (9)	
24	472-00	Structures & Improvements	31,009	2.41%	9,727	-	747	-	-	-	10,474	
25	472-10	Structures & Improvements - Byron Creek	107	4.67%	63	-	5	-	-	-	68	
26	473-00	Services	1,214,929	2.45%	314,452	-	29,461	(3,931)	-	-	339,982	
27	474-00	House Regulators & Meter Installations	174,221	5.99%	79,595	-	10,436	(5,271)	-	-	84,760	
28	474-02	Meters/Regulators Installations	195,236	4.55%	24,586	-	8,544	-	-	-	33,130	
29	475-00	Mains	1,498,152	1.54%	494,215	-	22,945	(1,944)	-	-	515,216	
30	476-00	Compressor Equipment	1,110	0.00%	105	-	-	-	-	-	105	
31	477-10	Measuring & Regulating Equipment	155,915	3.05%	55,493	-	4,679	(571)	-	-	59,601	
32	477-20	Telemetering	14,046	2.82%	6,632	-	388	(64)	-	-	6,956	
33	477-30	Measuring & Regulating Equipment - Byron Creek	163	0.00%	216	-	-	-	-	-	216	
34	478-10	Meters	279,209	7.09%	157,937	-	19,439	(3,512)	-	-	173,864	
35	478-20	Instruments	11,944	2.99%	3,517	-	357	-	-	-	3,874	
36			$ 3,580,248		$ 1,146,529	$ -	$ 97,001	$ (15,293)	$ -	$ -	$ 1,228,237	
37												
38		**BIO GAS**										
39	472-00	Bio Gas Struct. & Improvements	$ 661	2.72%	$ 90	$ -	$ 18	$ -	$ -	$ -	$ 108	
40	475-10	Bio Gas Mains – Municipal Land	1,622	1.55%	93	-	25	-	-	-	118	
41	475-20	Bio Gas Mains – Private Land	55	1.55%	6	-	1	-	-	-	7	
42	418-10	Bio Gas Purification Overhaul	20	5.00%	5	-	1	-	-	-	6	
43	418-20	Bio Gas Purification Upgrader	9,897	4.89%	1,860	-	484	-	-	-	2,344	
44	477-40	Bio Gas Reg & Meter Equipment	2,600	3.24%	356	-	66	-	-	-	422	
45	478-30	Bio Gas Meters	36	5.02%	10	-	2	-	-	-	12	
46	474-10	Bio Gas Reg & Meter Installations	226	5.24%	41	-	12	-	-	-	53	
47	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
48			$ 15,117		$ 2,461	$ -	$ 609	$ -	$ -	$ -	$ 3,070	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2018	1/1/2019 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2019	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	$ 15,616	5.00%	$ 2,479	$ -	$ 781	$ -	$ -	$ -	$ 3,260	
3	476-20	NG Transportation LNG Dispensing Equipment	13,412	5.00%	2,245	-	671	-	-	-	2,916	
4	476-30	NG Transportation CNG Foundations	2,365	5.00%	399	-	118	-	-	-	517	
5	476-40	NG Transportation LNG Foundations	1,311	5.00%	297	-	66	-	-	-	363	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,494	10.00%	468	-	149	-	-	-	617	
7	476-60	NG Transportation CNG Dehydrator	488	5.00%	101	-	24	-	-	-	125	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 34,686		$ 5,989	$ -	$ 1,809	$ -	$ -	$ -	$ 7,798	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 33,449	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	18,123	6.04%	9,860	-	1,095	-	-	-	10,955	
14	482-20	Masonry Buildings	140,373	1.95%	30,355	-	2,737	(160)	-	-	32,932	
15	482-30	Leasehold Improvement	5,247	9.49%	2,908	-	498	(100)	-	-	3,306	
16	483-30	GP Office Equipment	5,582	6.67%	3,642	-	372	(338)	-	-	3,676	
17	483-40	GP Furniture	25,071	5.00%	8,213	-	1,254	(353)	-	-	9,114	
18	483-10	GP Computer Hardware	53,984	20.00%	21,852	-	10,797	(8,373)	-	-	24,276	
19	483-20	GP Computer Software	3,787	12.50%	3,181	-	473	(1,440)	-	-	2,214	
20	484-00	Vehicles	21,867	10.55%	10,200	-	2,307	-	-	-	12,507	
21	484-10	Vehicles - Leased	23,255	9.44%	21,495	-	938	(1,458)	-	-	20,975	
22	485-10	Heavy Work Equipment	858	6.38%	618	-	55	-	-	-	673	
23	485-20	Heavy Mobile Equipment	5,857	9.85%	3,619	-	577	-	-	-	4,196	
24	486-00	Small Tools & Equipment	55,793	5.00%	22,608	-	2,790	(1,044)	-	-	24,354	
25	487-20	Equipment on Customer's Premises	12	6.67%	9	-	1	(9)	-	-	1	
26	488-10	Telephone	2,905	6.67%	1,785	-	194	(260)	-	-	1,719	
27	488-20	Radio	12,119	6.67%	3,105	-	808	-	-	-	3,913	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 408,282		$ 143,467	$ -	$ 24,896	$ (13,535)	$ -	$ -	$ 154,828	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 6,790,291		$ 2,066,879	$ -	$ 200,821	$ (45,332)	$ -	$ -	$ 2,222,368	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(510)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(1,201)					
38		**Net Depreciation Expense**					$ 199,110					
39												
40		Cross Reference	Schedule 6.2, Line 34, Column 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars			12/31/2018	1/1/2019 Opening Adjt	CPCN's	Additions	Retirements	12/31/2019	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, 2019**
11 **($000s)**
12
13

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2018	1/1/2019 Opening Adjt	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2019	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%	125,699	-	4,238	-	-	129,937	
21									-	
22	**Total**	$ 177,648		$ 125,699	$ -	$ 4,238	$ -	$ -	$ 129,937	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	12/31/2018	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 287,077	$ 2,219	$ -	$ 5,332	$ -	$ 294,628	
3	Transmission Contributions	146,663	168	-	480	-	147,311	
4	Others	722	-	-	-	-	722	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 435,028	$ 2,387	$ -	$ 5,812	$ -	$ 443,227	
7								
8	**Amortization**							
9	Distribution Contributions	$ (109,298)	$ -	$ -	$ (6,712)	$ -	$ (116,010)	
10	Transmission Contributions	(52,352)	-	-	(2,173)	-	(54,525)	
11	Others	(824)	-	-	(108)	-	(932)	
12	Biomethane	(189)	-	-	(28)	-	(217)	
13	**Total**	$ (162,663)	$ -	$ -	$ (9,021)	$ -	$ (171,684)	
14								
15	**Net CIAC**	$ 272,365	$ 2,387	$ -	$ (3,209)	$ -	$ 271,543	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (9,021)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,993)			

NET SALVAGE CONTINUITY SCHEDULE Schedule 10
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2018	Net Salv Provision	Retirement Costs / 12/31/2019	12/31/2019	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	$ 875	0.03%	$ -	$ -	$ -	$ -	
3	442-00	Structures & Improvements (Tilbury)	102,524	0.36%	480	369	-	849	
4	443-00	Gas Holders - Storage (Tilbury)	86,188	0.45%	795	388	-	1,183	
5	448-11	Piping (Tilbury)	60,397	0.27%	165	163	-	328	
6	448-21	Pre-treatment (Tilbury)	46,459	0.46%	216	214	-	430	
7	448-31	Liquefaction Equipment (Tilbury)	125,440	0.54%	684	677	-	1,361	
8	449-00	Local Storage Equipment (Tilbury)	38,534	0.39%	745	148	-	893	
9	442-01	Structures & Improvements (Mount Hayes)	17,310	0.45%	156	78	-	234	
10	443-05	Gas Holders - Storage (Mount Hayes)	60,112	0.35%	420	210	-	630	
11	448-41	Send out Equipment(Tilbury)	4,646	0.27%	13	13	-	26	
12	448-51	Sub-station and Electric (Tilbury)	41,813	0.54%	228	226	-	454	
13	448-10	Piping (Mount Hayes)	11,488	0.27%	62	31	-	93	
14	448-20	Pre-treatment (Mount Hayes)	28,714	0.46%	264	132	-	396	
15	448-30	Liquefaction Equipment (Mount Hayes)	28,714	0.54%	310	155	-	465	
16	448-40	Send out Equipment (Mount Hayes)	22,960	0.27%	124	62	-	186	
17	448-50	Sub-station and Electric (Mount Hayes)	21,644	0.54%	234	117	-	351	
18	449-01	Local Storage Equipment (Mount Hayes)	6,363	0.28%	36	18	-	54	
19			$ 704,181		$ 4,932	$ 3,001	$ -	$ 7,933	
20									
21		**TRANSMISSION PLANT**							
22	462-00	Compressor Structures	$ 29,484	-0.02%	$ 454	$ (6)	$ -	$ 448	
23	463-00	Measuring Structures	14,018	0.57%	301	80	-	381	
24	464-00	Other Structures & Improvements	6,485	0.22%	58	14	-	72	
25	465-00	Mains	1,378,749	0.37%	18,737	5,087	-	23,824	
26	465-11	IP Transmission Pipeline - Whistler	42,288	0.34%	288	144	-	432	
27	465-30	Mt Hayes - Mains	6,299	0.32%	40	20	-	60	
28	466-00	Compressor Equipment	186,875	-0.12%	2,476	(223)	-	2,253	
29	467-30	Mt. Hayes - Measuring and Regulating Equipment	5,342	0.21%	207	11	-	218	
30	467-10	Measuring & Regulating Equipment	59,405	0.22%	454	131	-	585	
31	467-31	IP Intermediate Pressure Whistler	313	0.22%	2	1	-	3	
32	468-00	Communication Structures & Equipment	3,795	-0.38%	416	(15)	-	401	
33			$ 1,733,053		$ 23,433	$ 5,244	$ -	$ 28,677	
34									
35		**DISTRIBUTION PLANT**							
36	472-00	Structures & Improvements	$ 31,009	0.32%	$ 325	$ 99	$ -	$ 424	
37	473-00	Services	1,214,929	1.61%	26,586	19,360	(9,962)	35,984	
38	474-00	House Regulators & Meter Installations	174,221	1.77%	(5,418)	3,083	(3,700)	(6,035)	
39	474-02	Meters/Regulators Installations	195,236	0.00%	1,594	-	-	1,594	
40	475-00	Mains	1,498,152	0.43%	29,887	6,407	(569)	35,725	
41	476-00	Compressor Equipment	1,110	0.00%	711	-	-	711	
42	477-10	Measuring & Regulating Equipment	155,915	0.46%	3,675	706	-	4,381	
43	477-20	Telemetering	14,046	0.42%	89	58	-	147	
44	478-10	Meters	279,209	-0.26%	3,154	(713)	-	2,441	
45			$ 3,563,827		$ 60,603	$ 29,000	$ (14,231)	$ 75,372	
46									
47		**BIO GAS**							
48	472-00	Bio Gas Struct. & Improvements	$ 661	0.29%	$ 2	$ 2	$ -	$ 4	
49	475-10	Bio Gas Mains – Municipal Land	1,622	0.39%	6	6	-	12	
50	475-20	Bio Gas Mains – Private Land	55	0.39%	2	-	-	2	
51	418-20	Bio Gas Purification Upgrader	9,897	0.26%	26	26	-	52	
52	474-10	Bio Gas Reg & Meter Installations	226	1.35%	3	3	-	6	
53			$ 12,461		$ 39	$ 37	$ -	$ 76	
54									
55		**GENERAL PLANT & EQUIPMENT**							
56	482-10	Frame Buildings	$ 18,123	0.00%	$ (12)	$ -	$ -	$ (12)	
57	482-20	Masonry Buildings	140,373	0.25%	642	351	-	993	
58	484-00	Vehicles	21,867	-1.00%	(328)	(219)	-	(547)	
59	485-10	Heavy Work Equipment	858	-0.68%	(12)	(6)	-	(18)	
60	485-20	Heavy Mobile Equipment	5,857	-2.89%	(339)	(169)	-	(508)	
61			$ 187,078		$ (49)	$ (43)	$ -	$ (92)	
62									
63		**Total**	$ 6,200,600		$ 88,958	$ 37,239	$ (14,231)	$ 111,966	
64		Less: Depreciation & Amortization Transferred to Biomethane BVA				(26)			
65		**Net Salvage Depreciation Expense**				$ 37,213			

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	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)	$ (54,890)	$ -	$ -	$ -	$ -	$ 37,596	$ (10,151)	$ (27,445)	$ (41,168)	
3	Commodity Cost Reconciliation Account (CCRA)	(19,541)	-	26,768	(7,227)	-	-	-	-	(9,771)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,902)	-	-	-	-	6,097	(1,646)	(4,451)	(6,677)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(7,032)	-	2,915	(787)	200	273	(74)	(4,505)	(5,769)	
6	Revelstoke Propane Cost Deferral Account	(19)	-	26	(7)	-	-	-	-	(10)	
7	SCP Mitigation Revenues Variance Account	352	-	-	-	(275)	-	-	77	215	
8	Pension & OPEB Variance	(4,093)	-	-	-	2,845	-	-	(1,248)	(2,671)	
9	BCUC Levies Variance	2,527	-	2,991	(808)	(2,527)	-	-	2,183	2,355	
10	TESDA Overhead Allocation Variance	596	-	782	(211)	(596)	-	-	571	584	
11		$ (91,002)	$ -	$ 33,482	$ (9,040)	$ (353)	$ 43,966	$ (11,871)	$ (34,818)	$ (62,912)	
12	**2. Rate Smoothing Accounts**										
13											
14	**3. Benefits Matching Accounts**										
15	Energy Efficiency & Conservation (EEC)	$ 100,789	$ 30,793	$ 15,000	$ (4,050)	$ (15,103)	$ -	$ -	$ 127,429	$ 129,506	
16	NGV Conversion Grants	49	-	-	-	(20)	-	-	29	39	
17	Emissions Regulations	(4,271)	-	-	-	998	-	-	(3,273)	(3,772)	
18	On-Bill Financing Pilot Program	7	-	(2)	-	-	-	-	5	6	
19	Greenhouse Gas Reduction Regulation Incentives	30,383	-	11,825	(3,193)	(4,095)	-	-	34,920	32,652	
20	CNG and LNG Recoveries	(399)	-	-	-	399	-	-	-	(200)	
21	2014-2019 PBR	245	-	-	-	(245)	-	-	-	123	
22	2016 Cost of Capital Application	839	-	-	-	(419)	-	-	420	630	
23	2015-2019 Annual Review Costs	97	-	50	(14)	(97)	-	-	36	67	
24	2017 Rate Design Application	1,305	-	-	-	(261)	-	-	1,044	1,175	
25	2017 Long Term Resource Plan Application	510	-	105	(28)	(170)	-	-	417	464	
26	2019-2022 DSM Expenditures Application Costs	160	-	80	(22)	(40)	-	-	178	169	
27		$ 129,714	$ 30,793	$ 27,058	$ (7,307)	$ (19,053)	$ -	$ -	$ 161,205	$ 160,859	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	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	$ 7,929	$ -	$ -	$ -	$ (739)	$ -	$ -	$ 7,190	$ 7,560	
3	2010-2011 Customer Service O&M and COS	4,807	-	-	-	(3,251)	-	-	1,556	3,182	
4	Gas Asset Records Project	2,436	-	898	(242)	(850)	-	-	2,242	2,339	
5	BC OneCall Project	442	-	-	-	(260)	-	-	182	312	
6	Gains and Losses on Asset Disposition	20,444	-	-	-	(3,987)	-	-	16,457	18,451	
7	Net Salvage Provision/Cost	(87,268)	-	14,231	-	(37,239)	-	-	(110,276)	(98,772)	
8	PCEC Start Up Costs	744	-	-	-	(44)	-	-	700	722	
9	2020 Revenue Requirement Proceeding	183	-	1,000	(270)	-	-	-	913	548	
10	City of Surrey Operating Terms Application Costs	243	-	-	-	(97)	-	-	146	195	
11		$ (50,040)	$ -	$ 16,129	$ (512)	$ (46,467)	$ -	$ -	$ (80,890)	$ (65,463)	
12	**4. Retroactive Expense Accounts**										
13											
14	**5.Other Accounts**										
15	Pension & OPEB Funding	$ (193,398)	$ -	$ 2,300	$ -	$ -	$ -	$ -	$ (191,098)	$ (192,248)	
16	US GAAP Pension & OPEB Funded Status	102,877	-	-	-	-	-	-	102,877	102,877	
17	BFI Costs and Recoveries	(432)	-	-	-	-	-	-	(432)	(432)	
18	Residual Delivery Rate Riders	1,045	-	-	-	(1,045)	-	-	-	523	
19	BVA Balance Transfer	2,633	-	-	-		(3,607)	974	-	1,317	
20		$ (87,275)	$ -	$ 2,300	$ -	$ (1,045)	$ (3,607)	$ 974	$ (88,653)	$ (87,963)	
21											
22	**Total**	$ (98,603)	$ 30,793	$ 78,969	$ (16,859)	$ (66,918)	$ 40,359	$ (10,897)	$ (43,156)	$ (55,479)	
23	Less: Net Salvage Amortization Transferred to Biomethane BVA					26					
24	**Net Rate Base Deferred Amortization Expense**					$ (66,892)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	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	Flow-Through Account	(25,586)	-	(698)	-	26,284	-	-	-	(12,793)	
4	Marketer Cost Variance	(7)	-	8	(2)	-	-	-	(1)	(4)	
5		$ (25,593)	$ -	$ (690)	$ (2)	$ 26,284	$ -	$ -	$ (1)	$ (12,797)	
6	**2. Rate Smoothing Accounts**										
7	2017 & 2018 Revenue Surplus	$ (29,949)	$ -	$ (1,594)	$ -	$ 3,075	$ -	$ -	$ (28,468)	$ (29,209)	
8											
9	**3. Benefits Matching Accounts**										
10	EEC-Incentives	$ 30,793	$ (30,793)	$ 21,343	$ (5,647)	$ -	$ -	$ -	$ 15,696	$ 7,848	
11	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
12	Transmission Integrity Management Capabilities CPCN Development Costs	4,262	-	25,456	(6,672)	-	-	-	23,046	13,654	
13		$ 32,657	$ (30,793)	$ 46,799	$ (12,319)	$ -	$ -	$ -	$ 36,344	$ 19,104	
14	**4. Retroactive Expense Accounts**										
15											
16	**5.Other Accounts**										
17	US GAAP Uncertain Tax Positions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
18	Mark to Market - Hedging Transactions	48,458	-	-	-	-	-	-	48,458	48,458	
19	2014-2019 Earning Sharing Account	(1,427)	-	(39)	-	1,466	-	-	-	(714)	
20		$ 47,031	$ -	$ (39)	$ -	$ 1,466	$ -	$ -	$ 48,458	$ 47,744	
21											
22											
23	**Total Non Rate Base Deferral Accounts**	$ 24,146	$ (30,793)	$ 44,476	$ (12,321)	$ 30,825	$ -	$ -	$ 56,333	$ 24,842	

WORKING CAPITAL ALLOWANCE Schedule 13
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 15,138	$ 17,503	$ 2,365	Schedule 14, Line 29, Column 5
3					
4	Less: Funds Available				
5	Reserve for bad debts	(5,162)	(5,510)	(348)	
6	Employee Withholdings	(5,432)	(6,118)	(686)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	1,827	89	(1,738)	
10	Gas In Storage	45,346	28,998	(16,348)	
11	Inventory - Materials and Supplied	1,598	1,514	(84)	
12	Refundable Contributions	(317)	(577)	(260)	
13					
14	Total	$ 52,998	$ 35,899	$ (17,099)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2019 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 & Commercial Tariff Revenue	$ 1,077,334	38.3	$ 41,284,457		
4	Industrial Tariff Revenue	92,865	45.1	4,191,137		
5	Bypass and Special Rates	35,301	43.9	1,548,394		
6						
7	**Other Revenue**					
8	Late Payment Charges	2,546	38.3	97,512		
9	Connection Charges	3,203	38.3	122,675		
10	Other Utility Income	40,471	38.3	1,550,039		
11						
12	Total	$ 1,251,720		$ 48,794,214	39.0	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 369,282	(40.2)	$ (14,845,136)		
16	Operating and Maintenance	246,075	(25.5)	(6,274,913)		
17	Property Taxes	67,559	(2.0)	(135,118)		
18	Franchise Fees	7,793	(420.3)	(3,275,597)		
19	Carbon Tax	273,822	(29.1)	(7,968,220)		
20	GST	10,482	(38.8)	(406,702)		
21	PST	4,302	(37.1)	(159,604)		
22	Income Tax	51,103	(15.2)	(776,766)		
23						
24	Total	$ 1,030,418		$ (33,842,056)	(32.8)	
25						
26	Net Lag (Lead) Days				6.2	
27	Total Expenses				$ 1,030,418	
28						
29	Cash Working Capital				$ 17,503	

FORTISBC ENERGY INC. August 3, 2018 Section 11

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 15

Line No.	Particulars	2018 APPROVED	2019 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (323,338)	$ (344,465)	$ (21,127)	
2	Tax Gross Up	(119,591)	(127,405)	(7,814)	
3	DIT Liability/Asset - End of Year	$ (442,929)	$ (471,870)	$ (28,941)	
4	DIT Liability/Asset - Opening Balance	(428,277)	(458,905)	(30,628)	
5					
6	DIT Liability/Asset - Mid Year	$ (435,603)	$ (465,388)	$ (29,785)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 FORECAST at Existing Rates	2019 FORECAST Revised Revenue	2019 FORECAST at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	135,822	137,849		137,849	2,027	
3	Transportation Volume (TJ)	92,366	97,535		97,535	5,169	
4		228,188	235,383	-	235,383	7,196	Schedule 17, Line 25, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,121,022	$ 1,075,708	$ -	$ 1,075,708	$ (45,314)	
8	Deficiency (Surplus)	-	-	-	-	-	
9	Transportation	125,286	129,792	-	129,792	4,506	
10	Deficiency (Surplus)	-	-	-	-	-	
11	Total	1,246,308	1,205,500	-	1,205,500	(40,808)	Schedule 19, Line 31, Column 8
12				-			
13	**COST OF ENERGY**	424,275	369,282	-	369,282	(54,993)	Schedule 18, Line 25, Column 3
14							
15	**MARGIN**	822,033	836,218	-	836,218	14,185	
16							
17	**EXPENSES**						
18	O&M Expense (net)	241,481	246,075	-	246,075	4,594	Schedule 20, Line 44, Column 4
19	Depreciation & Amortization	222,212	226,184	-	226,184	3,972	Schedule 21, Line 15, Column 3
20	Property Taxes	67,157	67,559	-	67,559	402	Schedule 22, Line 8, Column 3
21	Other Revenue	(46,048)	(46,220)	-	(46,220)	(172)	Schedule 23, Line 12, Column 3
22	2018 Revenue Surplus	5,398	-	-	-	(5,398)	
23	Utility Income Before Income Taxes	331,833	342,620	-	342,620	10,787	
24							
25	Income Taxes	50,137	51,103	-	51,103	966	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 281,696	$ 291,517	$ -	$ 291,517	$ 9,821	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 4,370,603	$ 4,481,004		$ 4,481,004	$ 110,401	Schedule 2, Line 30, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.45%	6.51%		6.51%	0.06%	Schedule 26, Line 5, Column 6

FORTISBC ENERGY INC. August 3, 2018 Section 11

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	81,227.4	80,768.4	(459.0)	
4	Commercial				
5	Rate Schedule 2	30,296.5	30,209.8	(86.7)	
6	Rate Schedule 3	20,091.1	21,546.4	1,455.3	
7	Rate Schedule 23	10,315.4	9,557.9	(757.5)	
8	Industrial				
9	Rate Schedule 4	146.9	141.3	(5.6)	
10	Rate Schedule 5	2,674.6	3,129.4	454.8	
11	Rate Schedule 6	28.0	41.0	13.0	
12	Rate Schedule 7	246.0	316.1	70.1	
13	Rate Schedule 22 - Firm Service	11,263.5	11,343.9	80.4	
14	Rate Schedule 22 - Interruptible Service	18,445.3	22,036.2	3,590.9	
15	Rate Schedule 25	14,017.0	14,594.9	577.9	
16	Rate Schedule 27	7,269.1	7,887.7	618.6	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	8,582.0	9,819.3	1,237.3	
19	Rate Schedule 25	1,072.9	1,048.9	(24.0)	
20	Rate Schedule 46	1,111.2	1,696.2	585.0	
21	Byron Creek	230.8	75.2	(155.6)	
22	Burrard Thermal	-	-	-	
23	BC Hydro IG	16,425.0	16,425.8	0.8	
24	VIGJV	4,745.0	4,745.0	-	
25	Total	228,187.7	235,383.4	7,195.7	
26					
27	**REVENUE AT EXISTING RATES**				
28	Residential				
29	Rate Schedule 1	$ 739,420	$ 702,589	$ (36,831)	
30	Commercial				
31	Rate Schedule 2	228,598	214,907	(13,691)	
32	Rate Schedule 3	127,547	127,354	(193)	
33	Rate Schedule 23	35,141	32,484	(2,657)	
34	Industrial				
35	Rate Schedule 4	678	588	(90)	
36	Rate Schedule 5	14,352	15,327	975	
37	Rate Schedule 6	197	260	63	
38	Rate Schedule 7	1,056	1,194	138	
39	Rate Schedule 22 - Firm Service	6,539	6,568	29	
40	Rate Schedule 22 - Interruptible Service	19,286	22,910	3,624	
41	Rate Schedule 25	31,484	34,060	2,576	
42	Rate Schedule 27	11,088	11,959	871	
43	Bypass and Special Rates				
44	Rate Schedule 22 - Firm Service	788	788	-	
45	Rate Schedule 25	482	481	(1)	
46	Rate Schedule 46	9,174	13,489	4,315	
47	Byron Creek	106	118	12	
48	Burrard Thermal	-	-	-	
49	BC Hydro IG	15,735	15,736	1	
50	VIGJV	4,637	4,689	52	
51	Total	$ 1,246,308	$ 1,205,500	$ (40,808)	

FORTISBC ENERGY INC. August 3, 2018 Section 11

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 255,047	$ 217,846	$ (37,201)	
4	Commercial				
5	Rate Schedule 2	95,759	82,146	(13,613)	
6	Rate Schedule 3	60,192	55,083	(5,109)	
7	Rate Schedule 23	176	126	(50)	
8	Industrial				
9	Rate Schedule 4	394	315	(79)	
10	Rate Schedule 5	7,157	6,965	(192)	
11	Rate Schedule 6	66	72	6	
12	Rate Schedule 7	659	703	44	
13	Rate Schedule 22 - Firm Service	279	209	(70)	
14	Rate Schedule 22 - Interruptible Service	227	222	(5)	
15	Rate Schedule 25	227	192	(35)	
16	Rate Schedule 27	124	104	(20)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	146	191	45	
19	Rate Schedule 25	18	20	2	
20	Rate Schedule 46	3,804	5,088	1,284	
21	Byron Creek	-	-	-	
22	Burrard Thermal	-	-	-	
23	BC Hydro IG	-	-	-	
24	VIGJV	-	-	-	
25	Total	$ 424,275	$ 369,282	$ (54,993)	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved Margin	2019 FORECAST Margin at Existing Rates	2019 FORECAST Effective Increase	2019 FORECAST Margin at Revised Rates	2019 FORECAST Revenue at Existing Rates	2019 FORECAST Effective Increase	2019 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	$ 484,373	$ 484,743	$ -	$ 484,743	$ 702,589	$ -	$ 702,589	928,147	80,768.4	
4	Commercial										
5	Rate Schedule 2	132,839	132,761	-	132,761	214,907	-	214,907	88,391	30,209.8	
6	Rate Schedule 3	67,355	72,271	-	72,271	127,354	-	127,354	5,629	21,546.4	
7	Rate Schedule 23	34,965	32,358	-	32,358	32,484	-	32,484	1,740	9,557.9	
8	Industrial										
9	Rate Schedule 4	284	273	-	273	588	-	588	18	141.3	
10	Rate Schedule 5	7,195	8,362	-	8,362	15,327	-	15,327	263	3,129.4	
11	Rate Schedule 6	131	188	-	188	260	-	260	11	41.0	
12	Rate Schedule 7	397	491	-	491	1,194	-	1,194	6	316.1	
13	Rate Schedule 22 - Firm Service	6,260	6,359	-	6,359	6,568	-	6,568	14	11,343.9	
14	Rate Schedule 22 - Interruptible Service	19,059	22,688	-	22,688	22,910	-	22,910	27	22,036.2	
15	Rate Schedule 25	31,257	33,868	-	33,868	34,060	-	34,060	558	14,594.9	
16	Rate Schedule 27	10,964	11,855	-	11,855	11,959	-	11,959	112	7,887.7	
17	Total Non-Bypass	$ 795,079	$ 806,216	$ -	$ 806,216	$ 1,170,199	$ -	$ 1,170,199	1,024,916	201,573.0	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 642	$ 597		$ 597	$ 788		$ 788	6	9,819.3	
22	Rate Schedule 25	464	461		461	481		481	4	1,048.9	
23	Rate Schedule 46	5,370	8,401		8,401	13,489		13,489	33	1,696.2	
24	Byron Creek	106	118		118	118		118	1	75.2	
25	Burrard Thermal	-	-		-	-		-	-	-	
26	BC Hydro IG	15,735	15,736		15,736	15,736		15,736	1	16,425.8	
27	VIGJV	4,637	4,689		4,689	4,689		4,689	1	4,745.0	
28	Total Bypass & Special	$ 26,954	$ 30,002	$ -	$ 30,002	$ 35,301	$ -	$ 35,301	46	33,810.4	
29											
30											
31	Total	$ 822,033	$ 836,218	$ -	$ 836,218	$ 1,205,500	$ -	$ 1,205,500	1,024,962	235,383.4	
32											
33	**Effective Increase**			0.00%			0.00%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 20

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base O&M	$ 228,020			
3	Less: O&M tracked outside of Formula	(30,721)			
4	O&M Subject to Formula	197,299			
5	**2014**				
6	Net Inflation Factor	100.621%			Schedule 3, Line 12, Column 3
7	FEI Formula O&M	198,524			
8	Add: FEVI/FEW Base O&M	38,498			
9	Less: FEVI Pension & OPEB's	(2,016)			
10	Less: FEVI Insurance	(1,250)			
11	Less: FEVI NGT Station O&M	(44)			
12	Total	233,712			
13	**2015**				
14	Net Inflation Factor	100.816%			Schedule 3, Line 12, Column 4
15	Formula O&M	235,619			
16	**2016**				
17	Net Inflation Factor	101.039%			Schedule 3, Line 12, Column 5
18	Formula O&M	238,068			
19	Less: Fort Nelson Line Heater and Communications Cost	(30)			
20	Formula O&M	238,038			
21	**2017**				
22	Net Inflation Factor	100.997%			Schedule 3, Line 12, Column 6
23	Formula O&M	$ 240,412			
24	**2018**				
25	Net Inflation Factor	101.320%			Schedule 3, Line 12, Column 7
26	Formula O&M	$ 243,585			
27	**2019**				
28	Net Inflation Factor	102.192%			Schedule 3, Line 12, Column 8
29	Formula O&M	$ 248,924		$ 248,924	
30					
31	**O&M Tracked Outside of Formula**				
32	Pension & OPEB (O&M Portion)		$ 13,795		
33	Insurance		5,473		
34	Biomethane O&M		1,369		
35	NGT O&M		2,339		
36	LNG Production O&M		7,432		
37	Employer Health Tax		2,630		
38	MSP		(829)		
39	Total		$ 32,209	32,209	
40					
41	**Total Gross O&M**			$ 281,133	
42	O&M Transferred to Biomethane BVA			(1,322)	
43	Capitalized Overhead			(33,736)	
44	**Net O&M Expense**			$ 246,075	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 191,560	$ 200,821	$ 9,261	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(471)	(510)	(39)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,260)	(1,201)	59	Schedule 7.2, Line 37, Column 7
5		189,829	199,110	9,281	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 56,624	$ 66,918	$ 10,294	Schedule 11.1, Line 22, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(24)	(26)	(2)	Schedule 11.1, Line 23, Column 6
10	Non-Rate Base Deferrals	(15,417)	(30,825)	(15,408)	Schedule 12, Line 23, Column 6
11	CIAC	(8,828)	(9,021)	(193)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		32,383	27,074	(5,309)	
14					
15	Total	$ 222,212	$ 226,184	$ 3,972	

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 APPROVED	2019 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 56,296	$ 55,245	$ (1,051)	
2	1% In-Lieu of Municipal Taxes	10,880	12,333	1,453	
3					
4	Total	$ 67,176	$ 67,578	$ 402	
5					
6	Total Property Tax Expense per Line 4	$ 67,176	$ 67,578		
7	Less: Property Tax Transferred to Biomethane BVA	(19)	(19)		
8	**Net Property Tax Expense**	$ 67,157	$ 67,559		

Schedule 23

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars		2018 Approved		2019 Forecast		Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
1	Late Payment Charge	$	2,688	$	2,546	$	(142)	
2	Connection Charge		3,148		3,203		55	
3	NSF Returned Cheque Charges		80		80		-	
4	Other Recoveries		288		288		-	
5	SCP Third Party Revenue		16,976		17,072		96	
6	NGT Tanker Rental Revenue		583		680		97	
7	NGT Overhead and Marketing Recovery		320		325		5	
8	Biomethane Other Revenue		532		614		82	
9	LNG Mitigation Revenue from FEI		18,039		18,039		-	
10	CNG & LNG Service Revenues		3,394		3,373		(21)	
11								
12	Total	$	46,048	$	46,220	$	172	

INCOME TAXES Schedule 24
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 281,696	$ 291,517	$ 9,821	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(134,461)	(140,563)	(6,102)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(11,680)	(12,790)	(1,110)	Line 36
4	Accounting Income After Tax	$ 135,555	$ 138,164	$ 2,609	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 185,692	$ 189,266	$ 3,574	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 50,137	$ 51,103	$ 966	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 50,137	$ 51,103	$ 966	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,300	$ 1,200	$ (100)	
19	Depreciation	189,829	199,110	9,281	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	41,183	36,067	(5,116)	Schedule 21, Line 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,020	944	(76)	
22	Vehicles: Interest & Capitalized Depreciation	1,352	1,255	(97)	
23	Pension Expense	11,933	9,273	(2,660)	
24	OPEB Expense	10,128	9,453	(675)	
25					
26	Deductions:				
27	Capital Cost Allowance	(213,970)	(214,235)	(265)	Schedule 25, Line 26, Column 6
28	CIAC Amortization	(8,800)	(8,993)	(193)	Schedule 21, Line 11+12, Column 3
29	Debt Issue Costs	(1,379)	(1,976)	(597)	
30	Vehicle Lease Payment	(1,603)	(993)	610	
31	Pension Contributions	(13,659)	(14,594)	(935)	
32	OPEB Contributions	(2,112)	(1,833)	279	
33	Overheads Capitalized Expensed for Tax Purposes	(11,025)	(11,245)	(220)	
34	Removal Costs	(13,937)	(14,231)	(294)	Schedule 11.1, Line 7, Column 4
35	Major Inspection Costs	(1,940)	(1,992)	(52)	
36	Total	$ (11,680)	$ (12,790)	$ (1,110)	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Class	CCA Rate	12/31/2018 UCC Balance	Adjustments	2019 Additions	2019 CCA	12/31/2019 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,053,275	$ -	$ 10,179	$ (42,335)	$ 1,021,119
2	1 (LNG Plant - post Feb 2015)	4%	17,202	-	-	(688)	16,514
3	1(b)	6%	67,137	-	7,439	(4,251)	70,325
4	2	6%	98,317	-	-	(5,899)	92,418
5	3	5%	1,871	-	-	(94)	1,777
6	6	10%	328	-	-	(33)	295
7	7	15%	25,184	-	2,553	(3,969)	23,768
8	8	20%	29,399	-	7,474	(6,627)	30,246
9	10	30%	10,911	-	2,800	(3,693)	10,018
10	10.1	30%	322	-	-	(97)	225
11	12	100%	6,631	-	13,635	(13,449)	6,817
12	13	manual	3,213	-	204	(490)	2,927
13	14	manual	100	-	-	(25)	75
14	14.1 (pre 2017)	7%	18,959	-	-	(1,327)	17,632
15	14.1 (post 2016)	5%	1,818	-	492	(103)	2,207
16	17	8%	1,236	-	-	(99)	1,137
17	38	30%	1,107	-	-	(332)	775
18	43.2	50%	1,304	-	-	(652)	652
19	45	45%	6	-	-	(3)	3
20	47	8%	195,388	-	-	(15,631)	179,757
21	47 (LNG Plant - post Feb 2015)	8%	211,815	-	2,267	(17,036)	197,046
22	49	8%	308,334	-	217,983	(33,386)	492,931
23	50	55%	11,645	-	9,850	(9,114)	12,381
24	51	6%	851,029	-	128,018	(54,902)	924,145
25							
26	Total		$ 2,916,531	$ -	$ 402,894	$ (214,235)	$ 3,105,190

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 APPROVED Earned Return	2019 Amount	2019 Ratio	2019 Average Embedded Cost	2019 Cost Component	2019 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 129,783	$ 2,636,011	58.83%	5.19%	3.05%	$ 136,849	$ 7,066	Schedule 27, Line 31&33, Column 5&6&7
2	Short Term Debt	4,678	119,806	2.67%	3.10%	0.08%	3,714	(964)	
3	Common Equity	147,235	1,725,187	38.50%	8.75%	3.37%	150,954	3,719	
4									
5	Total	$ 281,696	$ 4,481,004	100.00%		6.51%	$ 291,517	$ 9,821	
6									
7	Cross Reference		Schedule 2, Line 30, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2019
($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	120,466	121,307	2.644%	3,207	
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	3.823%	5,735	
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	November 1, 2018	November 1, 2048	148,500	150,000	3.957%	5,936	
15	2019 Medium Term Debt Issue	July 1, 2019	July 1, 2049	148,500	75,616	4.360%	3,297	
16								
17								
18	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
19	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
20								
21	LILO Obligations - Kelowna				16,320	6.936%	1,132	
22	LILO Obligations - Nelson				2,696	8.717%	235	
23	LILO Obligations - Vernon				7,895	10.108%	798	
24	LILO Obligations - Prince George				20,914	8.927%	1,867	
25	LILO Obligations - Creston				2,011	8.006%	161	
26								
27	Vehicle Lease Obligation				1,290	4.186%	54	
28								
29	Sub-Total				$ 2,643,049		$ 137,214	
30	Less: Fort Nelson Division Portion of Long Term Debt				(7,038)		(365)	
31	Total				$ 2,636,011		$ 136,849	
32								
33	Average Embedded Cost					5.19%		
34								
35	* 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 PBR Plan (identifying two exogenous factors that affect 2018 and 2019), 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 one new deferral account, the disposition of one existing deferral account and reports on the calculation of the balance in the Flow-through deferral account.

12.2 *EXOGENOUS (Z) FACTORS*

FEI is permitted to adjust the cost of service for "Exogenous Factors" under its PBR Plan. The following criteria have been established 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 Commission-defined materiality threshold.

The materiality threshold (item 5) for FEI has been established at $1.140 million, as approved by Commission Order G-164-14.

FEI has identified two exogenous factors that affect 2018 and 2019, as described below.

12.2.1 Employer Health Tax

Announced as part of the provincial government's Budget in February 2018, the Employer Health Tax (EHT) is a tax levied on businesses' payrolls and will come into effect on January 1, 2019. The EHT is an employer-paid payroll tax based on the remuneration to employees. The tax rate will start at 0.98 percent for annual payrolls in excess of $0.5 million and will gradually increase to 1.95 percent for B.C. payrolls in excess of $1.5 million per year. Details of payment schedules and rules for aggregating payrolls of related business are still to be determined through pending legislation.

The EHT is a new tax expense for companies in B.C. and meets the exogenous factor criteria identified below.

- The costs are attributable entirely to the provincial government's introduction of the new mandatory payroll tax, which is an event outside the control of a prudently operated utility.
- The costs, which are described in sections 6.3.6 and 7.2.2, are directly and solely attributable to the exogenous event (tax implementation). The tax, introduced for the first time in 2018, was not included in the 2013 base O&M expense or base capital used to determine costs under the PBR formula.
- This exogenous event, which occurs in 2019, could not have been foreseen at the time the base O&M expense and base capital were set.
- The costs are prudently incurred; FEI is legally obligated to comply with tax legislation.
- The costs are estimated at $3.3 million in total for 2019, which exceed the materiality threshold of $1.14 million. The O&M portion of the EHT is forecast to be $2.630 million, with a further $0.481 million in capital expenditures, $0.140 million in asset removal cost which are recorded in the net salvage deferral and $0.043 million in CMAE which is recovered through the CCRA.

The actual amount paid will vary depending on FEI's payroll remuneration in 2019 and details of the rules to be determined through pending legislation by the provincial government later this year. Variances between the amounts forecast and actual amounts paid will be returned to or recovered from customers in future years.

12.2.2 MSP Premium Reduction

On December 27, 2017, the provincial government announced the reduction of MSP premiums by 50 percent, effective January 1, 2018, and in the February 2018 provincial budget further announced the elimination of MSP premiums by January 1, 2020.

The MSP premium reduction meets the exogenous factor criteria identified above.

- The savings are attributable entirely to the provincial government's reduction in MSP premiums, which is an event outside the control of a prudently operated utility.
- The savings, which are described in sections 6.3.7 and 7.2.2, are directly and solely attributable to the exogenous event. The premium reduction, implemented in 2018, reduces benefits costs that were included in the 2013 base O&M expense and base capital used to determine costs under the PBR formula.
- This exogenous event, which occurred in 2018, could not have been foreseen at the time the base O&M expense and base capital were set.
- The savings are prudently incurred; MSP premiums are set by provincial legislation.
- The savings are forecast at $1.038 million in 2018 and 2019, which together exceeds the materiality threshold of $1.14 million. The O&M portion of the premium reduction is

forecast to be $0.829 million in each year, with a further $0.152 million in capital, $0.044 million in asset removal cost recorded in the net salvage deferral and $0.013 million in CMAE which is recovered through the CCRA.

The actual reductions will vary depending on the number of employees for whom FEI pays the MSP premium in 2018 and 2019. Variances between the amounts forecast and actual reductions will be returned to or recovered from customers in future years.

12.3 *ACCOUNTING MATTERS*

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

12.3.1 Emerging US GAAP Accounting Guidance

In the PBR Decision, the Commission 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." FEI discusses two US GAAP accounting standards with the impacts set out below:

- For ASU 2016-02 Accounting Standards Codification (ASC) Topic 842 Leases – the accounting assessment of this new standard continues throughout 2018; however, the effect on FEI's 2019 Annual Review is not expected to be significant.
- Cloud Computing – as cloud computing accounting guidance continues to evolve, FEI requests approval to capitalize cloud computing implementation costs consistent with traditional on-premise Information Systems (IS) hardware and software for 2019.

12.3.1.1 Leases

In February 2016, FASB issued ASU No. 2016-02, *Leases (ASC Topic 842*) which supersedes lease requirements in ASC Topic 840, *Leases*. The main provision of ASC Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. This standard is effective for FEI beginning on January 1, 2019. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows.

The recognition, measurement and presentation of leases on the statement of earnings will not significantly change from the current US GAAP. The new standard either classifies costs as lease expense for operating leases or interest expense on the lease liability and amortization of the right-of-use asset for finance leases which is consistent with the current guidance.

FEI is currently in the process of assessing its arrangements that qualify as operating leases which will need to be recorded as assets and liabilities on the balance sheet for external financial reporting purposes unless they are determined to be immaterial. FEI's assessments to date have identified its agreements to rent muster stations and office space to be recognized as right-of-use assets and lease liabilities, although the analysis of other agreements will continue throughout 2018. FEI's conclusions on the recognition of its leases under the new standard are subject to final review by the Company's external auditors and could be affected by certain utility industry interpretative issues which remain outstanding.

While FEI's analysis to date does not suggest it is necessary to change how FEI recognizes its lease arrangements for regulatory purposes in its 2019 Annual Review, the final assessments and conclusions could result in timing differences between how FEI recognizes leases for rate-setting purposes and how it is necessary to recognize the leases for external accounting purposes. Since future revenues are reasonably expected to permit recovery or refund of any lease timing differences arising from the implementation of ASC 842 over the term of the lease arrangements in future revenue requirements, FEI would recognize any such timing differences as either a regulatory asset or liability for external financial reporting purposes. As such, for the 2019 Annual Review, FEI has not reflected right-of-use assets, lease liabilities or deferral accounts resulting from the implementation of ASC 842 in its financial schedules.

12.3.1.2 Cloud Computing

FEI is requesting approval of a one-year variance from US GAAP to capitalize cloud computing implementation costs in 2019, consistent with a new accounting standard expected to be effective in 2020.

FEI continues to pursue IS solutions that better meet customer expectations, make business processes more efficient and replace end of life existing IS platforms with cost effective solutions. While these opportunities are initially identified by FEI, the form in which the solution is offered, either through traditional on-premise software or through cloud computing, is not known until discussions occur with the external vendor. An increasing number of IS solutions are being offered in the form of off-premise cloud computing services. Cloud computing includes Software as a Service (SaaS), whereby an entity runs applications from the cloud service provider on a subscription basis, and Infrastructure as a Service (IaaS), whereby an entity procures a subscription for managed infrastructure services, such as servers, from a central provider. Cloud computing services replace traditional on-premise hardware and software that are recognized as capital expenditures for financial statement and regulatory purposes.

Accounting Standards Update 2015-05 Intangibles – Goodwill and Other – Internal – Use Software – Cloud Computing Arrangements (ASU 2015-05) was issued in 2015. This guidance states that if a cloud computing arrangement does not meet the criteria of "having a software license", as defined below, the entity procuring the cloud service should account for the arrangement as a service contract, which would generally mean expensing such costs. The criteria for an entity "having a software license" is specifically defined as follows:

- The contractual right to take possession of the software at any time during the hosting period without significant penalty, and
- It is feasible for the entity to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software.

Based on *ASU 2015-05*, it is the external vendor costs for implementation performed on the premise of the vendor that are to be expensed pursuant to ASU 2015-05. These implementation costs could include the design, setup and configuration of the cloud computing software by the external vendor.

As technology evolves and businesses in all industries continue to obtain the benefits of implementing cloud computing solutions, the shortcomings of ASU 2015-05 are becoming apparent. This is in part due to the fact that software and hardware purchased as on-premise is not functionally different under cloud computing solutions; rather, it is the location of the asset that is different. Although traditional and cloud computing solutions are functionally the same, *ASU 2015-05* results in recognizing cloud computing implementation costs as O&M. Based on the criteria in *ASU 2015-05,* FEI cannot forecast which of its future cloud computing solutions will have agreements with external vendors that will have provisions that meet the above criteria until the projects are further along in the process. This creates uncertainty from the outset around whether future cloud computing expenditures will be O&M or capital pursuant to *ASU 2015-05*.

The accounting standard setters recognize the need for improvements in the accounting for cloud computing solutions. In June 2018, the Financial Accounting Standards Board (FASB) agreed to issue a final ASU in the third quarter of 2018 based on the March 1, 2018 issuance of the *Exposure Draft: Proposed ASU (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is A Service Contract.* The primary consensus reached for the new ASU is that the capitalization of implementation costs incurred for a cloud computing arrangement that is a service contract is consistent with the capitalization of implementation costs incurred to develop or obtain on-premise software and hardware. The other relevant consensus reached includes the requirement for an entity to expense those implementation costs over the term of the hosting arrangement, which includes periods covered under renewal options that are reasonably certain to be exercised. The new ASU is expected to have an effective date of January 1, 2020.

There is also a recognition in the utility industry that it is appropriate to capitalize cloud-based hardware and software and include such expenditures as capital assets. In 2016, the National Association of Regulatory Utility Commissioners (NARUC) approved the *Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements*. This resolution acknowledged that the utility industry is rapidly changing and that utilities are having to respond to modern customer expectations and evolutions in technology. The resolution also stated that "the existing regulatory accounting rules may be interpreted, if appropriate, to allow for utilities to capitalize cloud-based software".

NARUC encouraged State regulators to consider similar regulatory accounting treatment for cloud computing solutions as it would for on-premise solutions, which would be paid out of a utility's capital budget.

While the new ASU 350-40 supports the capitalization of initial external vendor cloud computing implementation costs and can be applied retroactively, it is not expected to become effective until 2020. FEI therefore requests approval to adopt the new guidance for rate-setting purposes beginning in 2019. There are a number of benefits of this approach:

- The proposed approach of capitalizing cloud computing implementation costs during 2019 would be consistent with the new ASU 350-40 that will become effective in 2020.
- The proposed approach would avoid a one-year change in capitalization policies and the associated potential volatility in O&M and capital.
- The proposed approach would remove that uncertainty regarding the treatment of IS implementation costs created by the existing guidance.
- The proposed approach keeps FEI's O&M and capital funding envelopes consistent with the 2013 Base O&M and capital amounts for the final year of the PBR term, which were based on the assumption that IS implementation costs would be capitalized.

FEI is therefore requesting approval for a one-year variance from US GAAP for 2019 to recognize initial cloud computing implementation costs as capital expenditures within the PBR capital formula. This treatment is consistent with the new ASU 350-40 which becomes effective in 2020 and is consistent with how on-premise computer hardware and software costs have traditionally been recognized for regulatory purposes.

12.4 *NON RATE BASE DEFERRAL ACCOUNTS*

In accordance with Directive 128 of Order G-138-14, FEI has included in its financial schedules a continuity of assets that are excluded from rate base, including deferred charges (Section 11, Schedule 12).

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 Commission approval, attract a weighted average cost of capital return (which is equal to a rate base return).

On May 3, 2017, the Commission issued is Regulatory Account Filing Checklist[54]. The purpose of this checklist is to facilitate an efficient review of applications for deferral accounts.

[54] Letter Log No. 53608, Appendix B.

The checklist classifies deferral accounts as either: (a) forecast variance accounts; (b) rate smoothing accounts; (c) benefit matching accounts; (d) retroactive expense accounts; or (e) other.

In the following sections FEI requests approval of one new deferral account and partial disposition of one approved deferral account. FEI also provides additional information for the Flow-through deferral account. Information on FEI's non-rate base Earnings Sharing and BVA deferral accounts is included in Section 10.

12.4.1 New Deferral Accounts

FEI is seeking approval of one new non-rate base deferral account to capture the two-phase development costs for FEI's Transmission Integrity Management Capabilities (TIMC) project[55]. The TIMC project will consist of system modifications required to enable the use of crack-detection inline inspection technology, also known as EMAT (Electro-Magnetic Acoustic Transducer). FEI expects to file a CPCN application for the TIMC project in mid-2020.

12.4.1.1 Transmission Integrity Management Capabilities (TIMC) Development Costs

FEI has initiated the development of the TIMC project, which will consist of modifications to FEI's transmission pipeline system to enable inline inspection with recently proven and commercialized crack-detection tools (commonly referred to as "EMAT tools", as the technology relies upon electro-magnetic acoustic transducers). EMAT tools[56] are primarily used for detecting and sizing anomalies associated with stress corrosion cracking and longitudinal seam welds (e.g. anomalies that may be associated with low-frequency electric resistance welding manufacturing processes) in FEI's transmission pipeline system.

Stress corrosion cracking has been responsible for failures on Canadian pipeline systems constructed before 2000, and is recognized by pipeline operators, pipeline regulators, and pipeline technical associations as a time-dependent integrity risk that must be managed. While FEI has not had any pipeline failures cause by SCC, this type of corrosion has been previously detected in the Company's pipeline system. EMAT inline inspection tools have been evolving especially over the past decade and are now increasingly being adopted by Canadian gas transmission pipeline operators as the standard method for managing stress corrosion cracking.

FEI has determined that process changes and infrastructure modifications with costs exceeding the FEI CPCN threshold will be required prior to the adoption of EMAT technology on a

[55] FEI is in progress in determining a project name to be used for future regulatory and public communication; however, "TIMC project" has been adopted for the purposes of this introductory submission.

[56] EMAT is a non-destructive testing technology that has applications in a wide range of industrial sectors. EMAT is generally used to assess the condition of manufactured objects and the technology is particularly effective for detection of stress corrosion cracking and disbonded coating. The EMAT generates an ultrasonic pulse within a metallic and/or ferromagnetic test object. The sound waves are generated in the material and thus no couplant is needed.

significant portion of its transmission pipeline system. To determine the specific system modifications that will be required, FEI is evaluating factors such as the following:

- Tool travel speed within the pipeline
  - As compared to other currently adopted tools in FEI's inline inspection program, EMAT tools and technology require slower travel speeds inside of a pipeline. Complete data collection relies on adequate time being provided for signal travel through the pipeline wall and for data collection by the tool. It is foreseeable that existing flow rates in FEI's pipelines may exceed EMAT tool specifications, requiring system-level modifications such as installation of pipeline loops to allow for necessary flow velocity control.
  - As EMAT sensors must make direct contact with the internal surface of the pipe, they are designed with a tighter fit inside a pipeline as compared to other currently adopted ILI tools. The resulting increased drag forces have the potential to result in speed fluctuations that exceed tool specifications. It is therefore foreseeable that pipeline configurations (e.g. bends, wall-thickness transitions) that were not previously a concern will become an impediment to a successful EMAT inspection. Areas of concern would foreseeably require pipe replacement to address EMAT tool incompatibilities.
- Tool length
  - EMAT tools are typically longer than other ILI tools currently adopted by FEI. Tool length also contributes to increased drag forces. As above, this can result in pipeline configurations that were not previously a concern to become an impediment to a successful inspection.
  - Tool length may also necessitate modifications to launcher and receiver barrels used for loading and unloading ILI tools.
- Capability to reduce the operating pressure of transmission pipelines for extended time periods
  - To enable appropriate engineering response to EMAT-identified anomalies and/or other time-dependent integrity concerns on its transmission pipeline system, FEI has determined that it needs to establish the capability to follow the common industry practice of implementing a 20 percent pressure reduction below the current operating pressure (which provides an equivalent safety factor of 1.25 to that current operating pressure) until such time that required mitigation and/or repair can be completed. To establish this capability without incurring interruption of customer supply will foreseeably require system modifications such as installation of pipeline loops.

Phase 1 of the CPCN development received internal FEI approval to proceed in Q2 of 2018 and comprises the work to assess long-term system implications for adopting EMAT technology and to determine the scope of work (i.e. the particular pipelines and their priority) for required system modifications. Phase 1 involves a quantitative risk assessment of FEI's transmission pipeline assets and will also establish sustainable processes for repeatable quantitative risk assessments required for the ongoing management and reassessment of FEI's aging transmission pipelines. Process enhancements include those required to provide traceable, verifiable, and complete data sets for quantitative risk assessments. Phase 1 is expected to be materially complete by the end of Q2 2019, with some smaller subsequent expenditures primarily related to the establishment of ongoing quantitative risk assessment capabilities.

Phase 2 of the CPCN development comprises the front-end engineering and design and other CPCN development costs, such as environmental assessments, and First Nations and stakeholder consultation. It is anticipated that Phase 2 will be initiated in 2019 and conclude in mid-2020 with a CPCN application.

The following table shows a forecast of expenditures related to Phases 1 and 2:

Table 12-1: CPCN Development Costs ($000s)

Line No.	Phase	2018	2019	2020	Total
1	Phase 1	$ 5,680	$ 5,710	$ 230	$ 11,620
2	Phase 2	-	19,000	11,000	30,000
3					
4	Total	**$ 5,680**	**$ 24,710**	**$ 11,230**	**$ 41,620**

FEI will propose an appropriate recovery treatment and period in its CPCN application for the TIMC project which will be submitted in conjunction with Phase 2.

Table 12-2 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to this deferral account request.

Table 12-2: 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 one new deferral account to capture the development costs related to the TIMC project.
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

Item	Consideration	Determination
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 account will capture TIMC development costs, mainly related to external consulting costs, data assessment and front-end engineering and design (FEED).
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	This account will capture costs during the development phase of the TIMC project. It is anticipated costs for this phase will be incurred from 2018 through 2021.
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 this deferral account, costs would have been forecast as a combination of O&M and capital expenses outside of the formula.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	The CPCN development costs are generally within FEI's control; however, it is accepted regulatory practice to defer development costs and recover them in a future period. This allows the costs of the complete project to be matched against when the benefits are realized, as well as to smooth the rate impact to customers from the recovery of the deferred costs. With respect to the need for the TIMC project itself, the project will enhance FEI's capability to manage time-dependent hazards, including stress corrosion cracking, within its transmission pressure pipeline system. Given the age of its transmission pipelines, their operating characteristics, and industry experience with pipelines of similar vintage and operation, FEI has determined that it is necessary and appropriate to initiate CPCN planning to enhance inspection capabilities at this time. In addition to FEI's determination of the necessity of this project, the project will address a commitment made in response to a BC Oil and Gas Commission (OGC) direction which requires FEI to establish a quantitative risk assessment process within its Integrity Management Program. This commitment was made in relation to an OGC review which determined that FEI's current process did not meet the full requirements of the CSA Z662-15 Clause 3.4.

Item	Consideration	Determination
b)	the degree of forecast uncertainty associated with the item;	FEI has proposed a two-phase deferral mechanism, in part to address the uncertainty in the Phase 2 and future years' costs (refer also to item VI below). During Phase 1, a quantitative risk assessment of FEI's transmission system will be conducted. This will allow the Company to better determine the urgency and priority for any necessary pipeline system modifications. This information will be used during Phase 2 to develop more detailed project scopes and estimates. Consequently, until the completion of Phase 1, the Phase 2 costs currently have a high degree of uncertainty. As further information becomes known, FEI will provide updates to the Commission as required through future rate filings. FEI forecasts additions to the deferral accounts based on the best estimate of costs at this time. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The TIMC development costs are material at an estimate of $41.620 million See Table 12-1 for further details.
d)	any impact on intergenerational equity	FEI will propose a recovery period that will match the costs and benefits of TIMC development so as to avoid any impact on intergenerational equity.
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 development cost accounts as benefit matching accounts since the costs are recovered over the period of time the benefits are generally incurred.
VI.	Identify if the regulatory account is a cash or non-cash account.	Development 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 are primarily comprised of consulting expenditures for the following two phases of work: • Phase 1 will deliver the scope of work (i.e. the particular pipelines that will require enhancements and/or modifications, and their priority) to enable the adoption of crack-detection tools within FEI's inline inspection program. • Phase 2 is for front-end engineering and design (FEED) work, and delivery of cost estimates for the preferred alternative and other identified alternatives as required by the BCUC CPCN guidelines. Phase 2 also

Item	Consideration	Determination
		includes required CPCN development costs such as environmental assessments, and First Nations and stakeholder consultation. Eligible costs also include in both Phase 1 and Phase 2 FEI's incremental internal costs to provide required direction, inputs, technical analyses, and other contributions to the work above. Additions will be captured during the development phase of the project only.
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.	FEI will propose an appropriate recovery mechanism in its CPCN application for the TIMC project (to be filed upon completion of Phase 2).
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.	FEI will propose an appropriate recovery period in its CPCN application for the TIMC project (to be filed upon completion of Phase 2).
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	FEI is requesting carrying costs based on its weighted average cost of capital (WACC). Non-rate base deferral accounts are generally financed using the WACC.
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The Commission's review of the TIMC development costs deferral account can occur as part of this annual review process. Approval of the TIMC project itself will be requested through a CPCN application, where the regulatory process will be included within the draft timetable.

12.4.2 Existing Deferral Accounts

12.4.2.1 2017 & 2018 Revenue Surplus

As part of the Annual Review for 2017 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[57]. The account is approved to attract a weighted average cost of capital return. As directed in Order G-182-16, "FEI is

[57] Line 28, Schedule 1 of Appendix A Financial Schedules attached to the Annual Review for 2017 Rates Order G-182-16 Compliance Filing.

directed to propose an amortization period for the 2017 Revenue Surplus deferral account as part of its annual review for 2018 delivery rates application."

In the Annual Review for 2018 Rates, FEI noted that it would propose an amortization period for this account in a future application. FEI also 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 to the deferral account. This amount was further amended through FEI's Compliance filing dated January 19, 2018 to $5.398 million, with Table 1 from that Application re-produced below.

Table 12-3: 2018 Compliance Filing change to Revenue Surplus addition

Compliance Filing - 2018 Rates						
Line Item	Revenue Surplus Impact ($ millions)	Delivery Rate Impact	Deferred Revenue Surplus ($ millions)	Delivery Rate Impact	Net Revenue Requirement Impact ($ millions)	Delivery Rate Impact
September 26, 2017 Evidentiary Update	**$ 7.960**	**-0.97%**	**$ (7.960)**	**0.97%**	**$ -**	**0.00%**
BC Budget - Corporate Income Tax Increase	(2.516)	0.31%	2.516	-0.31%	-	0.00%
BC Budget - Carbon Tax Increase	(0.046)	0.01%	0.046	-0.01%	-	0.00%
January 19, 2018 Compliance Filing	**$ 5.398**	**-0.65%**	**$ (5.398)**	**0.65%**	**$ -**	**0.00%**

Including the 2017 and 2018 weighted average cost of capital return credit additions to the deferral account, the ending 2018 after-tax balance in the deferral account is projected to be a credit of $29.949 million[58]. In this Application, FEI is requesting approval to amortize $3.075 million[59] of this amount into 2019 rates, which will result in a total 2019 forecasted revenue deficiency/surplus of zero and maintaining 2019 rates at existing 2018 levels[60]. FEI will make a similar request in future applications until the balance in the account is drawn down to zero.

12.4.2.2 Flow-Through Deferral Account

As approved through Commission Order G-162-14, 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 included in rates on a forecast basis and which do not have a previously approved deferral account. The specific items included in the Flow-through account were set out in Table 1 which was included in FEI's letter Response to Orders G-162-14 and G-163-14 filed with the Commission November 7, 2014 reproduced below.

[58] Section 11, Schedule 12, Line 7, Column 2
[59] Section 11, Schedule 12, Line 7, Column 6
[60] After implementation of approved (G-135-18) rate design changes

Table 12-4: 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 purchase variances	N/A	Flow-through deferral
Water fees variances	N/A	Flow-through deferral
Gross O&M:		
Formula driven O&M variances	Earnings sharing	Earnings sharing
BCUC fees variances	BCUC Variances deferral	Flow-through deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances *	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	N/A - no variance	N/A - no variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Depreciation and Amortization:		
Depreciation variances	Flow-through deferral	Flow-through deferral
Amortization of deferrals	N/A - no variance	N/A - no variance
Other Revenues (FEI)/Other Income (FBC):		
SCP Mitigation Revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
All other other revenue/income variances	Flow-through deferral	Flow-through deferral
Wheeling (FBC)/Transportation costs (FEI):		
Transportation and wheeling variances	Flow-through deferral	Flow-through deferral
Income Tax:		
Income tax variances	Flow-through deferral	Flow-through deferral
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas Storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
All other interest variances	Flow-through deferral	Flow-through deferral

* Including items re-forecast outside of the formula such as insurance premiums, AMI, NGT stations, Biomethane, RS46 O&M

In accordance with the method set out in the table, the calculation of the 2018 projected Flow-through amount of $18.189 million credit is shown in Table 12-5 below. To calculate the amount distributed to customers, FEI also included the following adjustments:

- The $6.532 million credit difference between the projected ending 2017 Flow-through deferral account balance embedded in 2018 delivery rates of a $12.502 million[61] credit

[61] Annual Review of 2018 Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 2.

and the actual ending 2017 deferral account balance of a $19.034 million credit, and the associated financing adjustment of a $0.865 million credit for 2018. The main contributors to the variance of $6.532 million were approximately $2.4 million in lower depreciation expense, $1.9 million in lower property taxes, and $1.7 million in additional 2017 actual delivery margin revenue compared to the 2017 projection in the amended Table 12-5 in the September 26, 2017 Evidentiary Update filing for the Annual Review of 2018 Rates Application.

- 2019 forecast financing of a $0.698 million credit[62]

Therefore, the total amount to return to customers through amortization in 2019 is a $26.284 million credit as shown in the non-rate base deferral section of the financial schedules in Section 11, Schedule 12.

Table 12-5: 2018 Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	Reference	2018 Approved	2018 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)	(5)
1	Delivery Margin				
2	Residential (Rate 1)		$ (484.373)	$ (485.917)	$ (1.544)
3	Commercial (Rate 2, 3, 23)		(235.159)	(237.907)	(2.748)
4	Industrial (All Others)		(75.547)	(81.051)	(5.504)
5	Total Delivery Margin		(795.079)	(804.875)	(9.796)
6					
7	O&M Tracked outside of Formula				
8	Insurance		5.360	5.284	(0.076)
9	Bio-Methane		1.121	1.929	0.808
10	Bio-Methane O&M transferred to BVA		(1.074)	(1.884)	(0.810)
11	NGT O&M		1.838	1.660	(0.178)
12	LNG Production O&M		6.650	6.506	(0.144)
13	MSP Reduction		-	(0.829)	(0.829)
14					
15	Property and Sundry Taxes		67.157	63.770	(3.387)
16					
17	Depreciation and Amortization		222.212	210.635	(11.577)
18					
19	Other Operating Revenue		(46.048)	(45.416)	0.632
20					
21	Interest Expense		134.461	135.056	0.595
22					
23	Income Taxes		50.137	56.710	6.573
24					
25	2018 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)				(18.189)
26					
27	2017 Ending Deferral Account Balance True-up				(6.532)
28	2018 Financing True-up				(0.865)
29	2019 Financing Addition to Deferral Account				(0.698)
30					
31	2019 After-Tax Amortization				(26.284)

[62] Section 11, Schedule 12, Line 3, Column 4.

The variances in delivery margin are due to favourable industrial margin as a result of higher volumes than forecast and interruptible volumes for the Vancouver Island Joint Venture, and favourable residential and commercial margin mainly as a result of higher customer additions than forecast. Variances in O&M Tracked Outside the Formula are shown in Section 6 and Property Taxes are shown in Section 9. The variance in depreciation and amortization is primarily due to the delay of the Tilbury project in-service date. Variances in Other Revenue are shown in Section 5. The variance in interest expense is due to a higher cost of short-term debt as a result of a higher projected 2018 rate base and short-term interest rate than forecasted, partially offset by a lower cost of long-term debt due to lower long-term debt than forecasted. Finally, the variance in income taxes is due to the income tax impacts of each of the aforementioned items, the tax related to the O&M formula variances after-sharing, and the variance between the projected and approved tax timing differences.

An adjustment to include the difference between the projected and final actual amounts for 2018 subject to flow-through will be recorded in the deferral account in 2019 and amortized in 2020 rates.

12.5 *SUMMARY*

FEI has two new exogenous factors that are affecting delivery rates in 2019, has provided an update on certain accounting related matters, requested approval for one new deferral account and the disposition of one existing deferral account, and included information on the Flow-through deferral account

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

SQIs form the basis of determining a utility's quality of service and represent a broad range of business processes that are important elements to the customer experience. Under the PBR Plan, SQIs are used to monitor the utility's performance to ensure that any cost reductions by the utility as a result of implementing productivity initiatives do not result in degradation of the quality of service to customers during the PBR period.

The Commission 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 Commission in Order G-14-15. Four of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

In 2016, the Commission issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The Commission determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The Commission stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

FEI agrees with the approach set out in this directive and believes the rationale applies equally to the review of its service quality under PBR. FEI has therefore added a review of its most recent year's (i.e. 2017) service quality to this section.

In the subsections below, FEI reports on its 2017 and June 2018 year-to-date performance as measured against the SQI benchmarks and thresholds. Both 2017 and June 2018 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2017, for the nine SQIs with benchmarks, all nine performed at or better than the approved benchmarks. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

June 2018 year-to-date performance is similar to 2017 with the nine SQIs with benchmarks performing at or better than the approved benchmarks.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's 2017 and June year-to-date performance for 2018 to the Commission-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation and that were approved by the Commission. Actual 2017 and June year-to-date results for 2018 are also provided for the four informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2017 Results	2018 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	97.8%	97.8%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	97.6%	97.8%
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	2.00	1.84
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	8	8
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	80%	82%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.75	2.58
Meter Reading Accuracy	Number of scheduled meters that were read	95%	92%	96.2%	95.1%
Telephone Service Factor (Non- Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%	71%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	93.8%	97.0%	96.4%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.6
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	1.9%	2.0%
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	4	2
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0047	0.0030

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2017 and 2018. 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 25,500 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 2017 result was 97.8 percent which was better than the benchmark at 97.7 percent and the threshold at 96.2 percent. In 2017, the company experienced an 11 percent increase in emergency calls and improved response time by 0.4 percent compared to 2016. The June 2018 year-to-date performance is 97.8 percent which is better than the benchmark.

The Company's 2009 to 2017 annual and 2018 year-to-date emergency response time results are provided below. The improved response time since 2014 in all operating zones is a reflection of a combination of factors including changes made to technician shift schedules starting January 2015. The changes to shift schedules were made to provide more emergency response capacity in the late afternoon and early evening.

Table 13-2: Historical Emergency Response Time

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Results	97.7%	97.7%	97.9%	97.4%	97.4%	96.7%	97.3%	97.4%	97.8%	97.8%
Benchmark	n/a	n/a	n/a	n/a	n/a	97.7%	97.7%	97.7%	97.7%	97.7%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2017 result was 97.6 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2018 year-to-date performance is 97.8 percent which is also better than the benchmark.

The Company's TSF (Emergency) results for 2009 to 2017 annual and 2018 year-to-date are provided below:

Table 13-3: Historical TSF (Emergency) Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Results	98.3%	99.2%	96.5%	96.5%	95.6%	95.8%	97.6%	98.5%	97.6%	97.8%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2017 (three-year rolling average) result was 2.00 which was better than the benchmark at 2.08 and the threshold at 2.95. The 2017 annual AIFR was 1.36 which reflected 9 Medical Treatments and 11 Lost Time Injuries.

The three-year rolling average of the annual results including 2018 June year-to-date results is 1.84 which is better than the benchmark. The 2018 year-to-date annual AIFR is 2.04 which reflected 9 Medical Treatments and 7 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.

Target Zero is the continual improvement program which was launched in January 2016. This program focuses on a number of key elements designed to enhance the existing safety management system and engage employees at all levels in safety as well as promote an interdependent safety environment. The Company believes this program has contributed to the positive safety trend experienced.

The Company's 2009 to 2017 and 2018 year-to-date AIFR results are provided below.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	2.49	2.66	1.66	1.91	3.02	1.73	2.52	2.13	1.36	2.04
Three year rolling average	2.55	2.26	2.27	2.08	2.20	2.22	2.42	2.13	2.00	1.84
Benchmark	n/a	n/a	n/a	n/a	n/a	2.08	2.08	2.08	2.08	2.08
Threshold	n/a	n/a	n/a	n/a	n/a	2.95	2.95	2.95	2.95	2.95

Public Contact with Pipelines

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 three-year rolling average of the annual results. The threshold of 16 is the same as the benchmark.

In its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates, the Commission directed as follows:

> The Panel also agrees that with regard to the SQI Public Contact with Pipelines, the number of line damages and the number of calls to BC One Call would be helpful and directs FEI to also provide this information in future annual reviews.

The number of line damages and number of calls to BC One Call is provided in Table 13-5 below.

The 2017 (three-year rolling average) result was 8, which is better than the benchmark of 16. The three-year rolling average of the June 2018 year-to-date results is also 8, also below and 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 three-year rolling average result reflects an ongoing positive trend for this metric. Increased awareness through targeted workshops with municipalities and excavating contractors, together with a higher number of calls generated by the BC One Call program have contributed to the improved performance. The increase in BC One calls is related to increased funding of the BC One Call program which has raised awareness.

The Company's 2009 to 2017 annual and 2018 year-to-date results along with the three-year rolling averages are provided below. The annual result has been trending downward as has the three-year rolling average. This is due to the historical upward trend in BC One Calls (increased awareness and increased construction activity) offset by an increase in the number of line damages resulting from the increased construction activities. The Company is taking steps to address the upward trend in line damages. FEI has hired Damage Prevention Investigators to focus on repeat damagers and work with Technical Safety BC to reduce line hits.

Table 13-5: Historical Public Contact with Pipeline Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	20	19	16	13	10	9	8	8	9	7
Three year rolling average	26	22	18	16	13	11	9	9	8	8
Benchmark	n/a	n/a	n/a	n/a	n/a	16	16	16	16	16
Threshold	n/a	n/a	n/a	n/a	n/a	16	16	16	16	16
Calls to BC One Call	72,691	78,734	82,396	86,828	92,002	107,509	122,627	129,645	146,868	80,970
Line Damages	1,435	1,457	1,329	1,094	955	954	1,035	1,086	1,247	561

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 2017 result was 80 percent which was better than the benchmark of 78 percent approved by the Commission. The June 2018 year-to-date performance is 82 percent and better than the benchmark.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. The improvement in 2012 reflects the repatriation of the contact centre function from a third party provider. Results have remained consistent after 2012.

Table 13-6: Historical First Contact Resolution Levels

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	72%	77%	75%	78%	81%	80%	81%	81%	80%	82%
Benchmark	n/a	n/a	n/a	n/a	n/a	78%	78%	78%	78%	78%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2017 result was 0.75 which was better than the benchmark of 5.0. The June 2018 year-to-date performance is 2.58 which is also better than the benchmark. No significant billing issues have arisen in 2017 or so far in 2018.

The 2017 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2017 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	99.995%	If (PA≥99.9%,5000*(1 - PA),1.05-PA))	=5000*(1-1)	0.24
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%	98.00%	(100%-PA)*100	=(100%-98%)*100	2.0
Billing Service Quality Indicator; Target < 5.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.24+0+2.0) /3	0.75

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. The results were higher in 2012 as that was the year when the Company transitioned its billing functions in-house from its previous third party provider; a process that included all new systems and employees during 2012.

Table 13-8: Historical Billing Index Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	3.75	2.4	0.24	3.01	1.43	0.89	1.06	0.57	0.75	2.58
Benchmark	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0	5.0
Threshold	n/a	n/a	n/a	n/a	n/a	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 2017 result was 96.2 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2018 year-to-date performance is 95.1 percent and is at the benchmark.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. As this SQI was not tracked prior to 2013, there are no results available for those years. The Company started tracking gas Meter Reading Accuracy in 2013 when the Gas monthly meter reading function was moved to a new third party meter reading vendor. Performance improved in 2014 after the new vendor stabilized their new meter reading staff and systems in the latter part of 2013.

Table 13-9: Historical Meter Reading Accuracy Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	n/a	n/a	n/a	n/a	92.5%	97.0%	97.5%	96.9%	96.2%	95.1%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2017 result was 71 percent which was better than the benchmark of 70 percent. The June 2018 year-to-date performance is 71 percent which is better than the benchmark.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. As indicated in the following table, the Company's TSF (Non-Emergency) results were consistent with a benchmark of 75 percent from 2009 to 2014. The 2014 result was achieved with the Company targeting 75 percent as the benchmark. The Commission approved the revised target of 70 percent in mid-September 2014. In 2015 and subsequent years, actual results are expected to be reflective of the revised target of 70 percent.

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

	2009	2010	2011	2012	2013	2014		2015	2016	2017	June 2018 YTD
	77%	77%	75%	76%	73%	75%		71%	71%	71%	71%
						Jan-Aug	Sept-Dec				
Benchmark	>=75%	>=75%	>=75%	>=75%	>=75%	>=75%	>=70%	70%	70%	70%	70%
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	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 2017 result was 97.0 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2018 year-to-date performance is 96.4 percent and also better than the benchmark. The June 2018 year-to-date result is consistent with the performance observed in recent years.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	94.7%	94.2%	96.5%	96.5%	97.0%	95.5%	96.6%	96.9%	97.0%	96.4%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	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 and mass market commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The 2017 result was 8.4, lower than the 8.8 score in 2016. Index contributor scores were lower in all areas. Although not conclusive, customer comments and statistical analysis suggest that the lower 2017 result may be associated with lower customer satisfaction with the cost of natural gas following commodity cost increases in October 2016, followed by a colder, wetter winter.

The June 2018 year-to-date average index score is 8.6, higher than the 8.3 score for the same period last year. Of the five measures that make up the overall score, year-to-date (June 2018 vs June 2017) results were higher in all categories. The score for overall satisfaction and accuracy of meter reading increased from 8.3 to 8.6 and 8.1 to 8.5, respectively. The energy conservation information, contact centre and field services metrics increased from 7.5 to 7.7, 8.2 to 8.5 and 8.9 to 9.0 respectively from June 2017 year-to-date to June 2018 year-to-date.

The Company's 2009 to 2017 annual and 2018 year-to-date results, in the previous and current formats, are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results – current format	n/a	n/a	8.3	8.3	8.3	8.5	8.6	8.8	8.4	8.6
Annual Results – prior format	80.1%	80.0%	79.3%	78.9%	n/a	n/a	n/a	n/a	n/a	n/a
Benchmark	n/a	n/a	n/a	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	n/a	n/a	n/a

For the years 2009 through 2012, the satisfaction scores were presented as percentages and reflect the results of a different customer satisfaction model. Originally introduced in 2002, the historical metric was calculated using the results of four satisfaction surveys, including a bi-annual residential survey, as well as annual builder-developer, small commercial and large commercial surveys. Each audience was assigned a contributing weight to determine a final index score, which was presented as a percentage. To maintain a level of comparability, the Company ran parallel CSI studies in 2011 and 2012. As shown in the table above, the CSI scores were 79.3 percent and 8.3 in 2011 and 78.9 percent and 8.3 in 2012.

Telephone Abandon Rate

The Telephone Abandon Rate is an informational indicator that measures the percent of calls abandoned by the customer before speaking to a customer service representative. Abandon rates can be due to waiting times, or due to customers receiving their required information through informational messages in the Company's Interactive Voice Response (IVR) system such that the customer no longer needs to speak to an agent.

The 2017 result was 1.9 percent and consistent with the prior years' results. The June 2018 year-to-date result of 2.0 percent is consistent with the Company's prior years' results.

The Company's 2012 to 2015 results, which are reflective of performance since the repatriation of outsourced Customer Service functions, are provided below. Telephone Abandon Rates prior to 2012 were not reported from our third party Customer Service provider.

Table 13-13: Historical Telephone Abandon Rates

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	n/a	n/a	n/a	2.2%	2.1%	1.8%	2.0%	2.2%	1.9%	2.0%
Benchmark	n/a	n/a	n/a	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	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 Commission, 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.

Prior to the third quarter of 2014, the practice was to report only on the higher pressure transmission events designated as serious. However, the OGC put in place new reporting criteria effective October 1, 2014, which required the Company to report on more incidents and events. As of October 1, 2014, the Company reports Transmission Reportable Incidents based on the new OGC reporting criteria, including Level 1, 2, and 3 reportable incidents for both transmission and intermediate pressure assets that operate at a pressure exceeding 100 psi. This includes pipelines, mains, services, stations, LNG plants and compressor stations, but excludes distribution assets that operate below 100 psi. The change in the OGC reporting criteria limits the comparability of historical performance data for this metric.

As directed by the Commission in its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates:

> For subsequent annual reviews, FEI is directed to report the number of Transmission Reportable Incidents in each of the severity levels.

The following table summarizes the transmission reportable incidents for 2015 through to June 2018 year-to-date by severity level.

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents in 2015	Reportable Incidents in 2016	Reportable Incidents in 2017	Reportable Incidents June YTD 2018
Level 1 (moderate)	3	3	4	2
Level 2 (major)	0	0	0	0
Level 3 (serious)	0	0	0	0

As indicated in the above table, the 2017 result was four Level 1 reported incidents.

- The first Level 1 incident occurred in February 2017 and involved an apparent attempt to siphon gas from an intermediate pressure farm tap in Chemainus on Vancouver Island.
- The second Level 1 incident occurred in June 2017 when a homeowner hit the intermediate pressure service line on his own private property.
- The third Level 1 incident occurred in August 2017 in Surrey when a creek diversion consisting of a dam and pump arrangement was breached. The creek diversion was created to enable construction of the Coastal Transmission System Project. The breach was due to flash flooding which exceeded the capacity of the pumps that the contractor had available. No release of gas occurred.
- The fourth Level 1 incident occurred in September 2017 and was the result of a contractor hitting a transmission pipeline while building an access road to a new residential development. The contractor had not called BC One Call to obtain location records, nor been issued a permit for work by FEI. Significant damage to the pipeline coating occurred. A stop work order was issued and the coating was repaired.

As also indicated in the table above from January 1 to June 30, 2018, there have been two Level 1 reportable incidents:

- The first Level 1 incident took place in April 2018 when a mud slide struck and exposed a Transmission Pipeline near Castlegar. The pipeline was dented and will require repair.
- The second Level 1 incident involved pipe along a section of river in the Falkland Valley that was exposed due to erosion. The potential for erosion was reported by patrols in April and May. The Company waited for water levels to recede in June before it could inspect and confirm the erosion..

The Company's 2009 to 2017 historical annual and 2018 year-to-date results are provided below. No comparable historical results under the new OGC reporting criteria are available for 2013 and prior years.

Table 13-15: Historical Transmission Reportable Incidents

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results – Level 1	n/a	n/a	n/a	n/a	n/a	1	3	3	4	2
Annual Results – Level 2	n/a	n/a	n/a	n/a	n/a	1	0	0	0	0
Annual Results – Level 3	n/a	n/a	n/a	n/a	n/a	0	0	0	0	0
Benchmark	n/a	n/a	n/a	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	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 Commission 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 Commission 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 13-16 below provides the historical data for the calculation of the June 2018 year-to-date five-year rolling average result of 0.0053 calculated using data from July 2013 to June 2018.

Table 13-16: June 2018 Year-to-Date Five Year Rolling Average

Period	Metric
July – December 2013 (6 months)	0.0037
January – December 2014	0.0059
January – December 2015	0.0045
January – December 2016	0.0047
January – December 2017	0.0047
January – June 2018 (6 months)	0.0030
Five Year Rolling Average	0.0053

The Company's 2009 to 2017 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 2018 year-to-date result is 0.0030 which is based on 69 leaks detected year-to-date as compared to 54 in 2017 and 58 in 2016 for a similar time period.

Table 13-17: Historical Leaks per KM of Distribution System Mains

Leaks per KM of Distribution System Mains	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Leaks	122	140	166	169	143	114	102	107	108	69
Total km	18,760	18,895	18,974	19,040	19,098	19,172	22,602	22,813	22,951	23,060
Leaks per km	0.0065	0.0074	0.0087	0.0089	0.0075	0.0059	0.0045	0.0047	0.0047	0.0030
5 year average	0.0062	0.0064	0.0067	0.0075	0.0078	0.0077	0.0071	0.0063	0.0055	0.0053

13.3 *ANNUAL GHG EMISSIONS*

In its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates, the Commission directed FEI to provide estimated annual GHG emissions reported to the Ministry of Environment, as follows:

> With regard to including the Estimated Annual GHG Emissions (in tCO2e) reported by the Company to the Ministry of Environment, the Panel has no objection, and directs FEI to provide this information in future annual reviews.

The 2017 GHG emissions value, excluding LNG operations[63], reported by FEI to the BC Ministry of Environment was 137,903 tCO2e. The 2016 reported value was 124,077 tCO2e.

13.4 *SUMMARY*

In summary, FEI's 2017 results and June 2018 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2017, for those SQIs with benchmarks, all nine performed at or better than the approved benchmarks with For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

[63] LNG operations are required to be reported separately and only if emissions exceed 10,000 tCO2e. Total LNG emissions for Mt. Hayes and the existing Tilbury LNG Plants were 4,631 tCO2e in 2017 and therefore no reporting to the BC MOE was required.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: CANSIM Table 326-0020

Français

Statistics Canada Statistique Canada

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Home → Data → Consumer Price Index, monthly, not seasonally adjusted → Add/Remove data

Add/Remove data

Consumer Price Index, monthly, not seasonally adjusted[1 2]

Frequency: Monthly

Table: 18-10-0004-01 (formerly CANSIM 326-0020)

Geography: Canada, Census metropolitan area, Census metropolitan area part, Census subdivision, Province or territory

► Customize table (Add/Remove data)

Download

	British Columbia (map)
Reference period	All-items
	2002=100
July 2016	123.3
August 2016	123.4
September 2016	123.2
October 2016	123.1
November 2016	122.7
December 2016	122.7
January 2017	123.5
February 2017	123.6
March 2017	124.2
April 2017	124.4
May 2017	125.0
June 2017	125.2
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

How to cite: Statistics Canada. Table 18-10-0004-01 Consumer Price Index, monthly, not seasonally adjusted

Table A1-2: CANSIM Table 281-0063

Français

Statistics Canada Statistique Canada

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Home → Data → Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted → Add/Remove data

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

► Customize table (Add/Remove data)

Download

	British Columbia (map)	
	Average weekly earnings including overtime for all employees [6]	
Reference period	Industrial aggregate including unclassified businesses [6,7]	Industrial aggregate excluding unclassified businesses [6,7]
	Dollars	
July 2016	..	916.30 [A]
August 2016	..	922.72 [A]
September 2016	..	919.27 [A]
October 2016	..	918.42 [A]
November 2016	..	927.27 [A]
December 2016	..	931.13 [A]
January 2017	..	930.35 [A]
February 2017	..	930.17 [A]
March 2017	..	934.96 [A]
April 2017	..	936.88 [A]
May 2017	..	940.14 [A]
June 2017	..	944.40 [A]
July 2017	..	937.98 [A]
August 2017	..	941.65 [A]
September 2017	..	952.43 [A]
October 2017	..	952.38 [A]
November 2017	..	952.81 [A]
December 2017	..	957.62 [A]
January 2018	..	956.68 [A]
February 2018	..	958.80 [A]
March 2018	..	963.03 [A]
April 2018	..	952.75 [A]
May 2018	..	959.86 [A]

Symbol legend:

.. : not available for a specific reference period

A : data quality: excellent

1 **Table A1-3: CBOC BC Housing Starts Embedded in Forecast as Filed**

January, 19,2018
Provincial Medium Term
Forecast: 20173 Run: 18
Table: 156 and 157

BRITISH COLUMBIA	2016	2017	2018	2019
Forecasted Single-Family Housing Starts (Units)	12,278	12,084	11,788	9,481
Forecast Percent Change	20.9	(1.6)	(2.4)	(19.6)
Forecasted Mult-Family Housing Starts (Units)	29,565	28,916	29,405	24,452
Forecast Percent Change	38.8	(2.2)	1.7	(16.8)
Forecast Housing Starts Total	41,843	41,000	41,193	33,933

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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. Historic and Forecast Data
   a. 2008-2017 actual data
   b. 2018 seed year data
   c. 2019 forecast data
2. Percent Error
   a. 2008-2017 forecast, actual and percent error

2. HISTORIC AND FORECAST DATA TABLES

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

FEI Customer Counts

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
RS 1	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	924,080	934,804
RS 2	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076	86,074	86,973	88,088	89,203
RS 3	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,441	5,532	5,623
RS 23	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,728	1,744
Industrial	1,145	1,113	1,017	951	954	981	977	976	955	976	978	978
NGT	0	0	0	2	5	10	18	31	42	56	66	68
Total	929,114	937,261	946,574	953,943	942,872	953,295	964,971	979,277	991,591	1,006,043	1,020,472	1,032,421

FEI Customer Additions

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
RS 1	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	13,195	10,724
RS 2	1,330	446	128	511	577	1,329	1,173	1,450	998	899	1,115	1,115
RS 3	171	-31	37	-16	-104	-86	35	132	-112	252	91	91
RS 23	3	42	58	27	88	9	-7	202	79	-91	16	16
Total	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	12,324	14,417	14,417	11,946

FEI Normalized Use Per Customer (Gjs)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
RS 1	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	86.4	87.0
RS 2	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	339.0	341.3
RS 3	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,763	3,831
RS 23	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,435	5,492

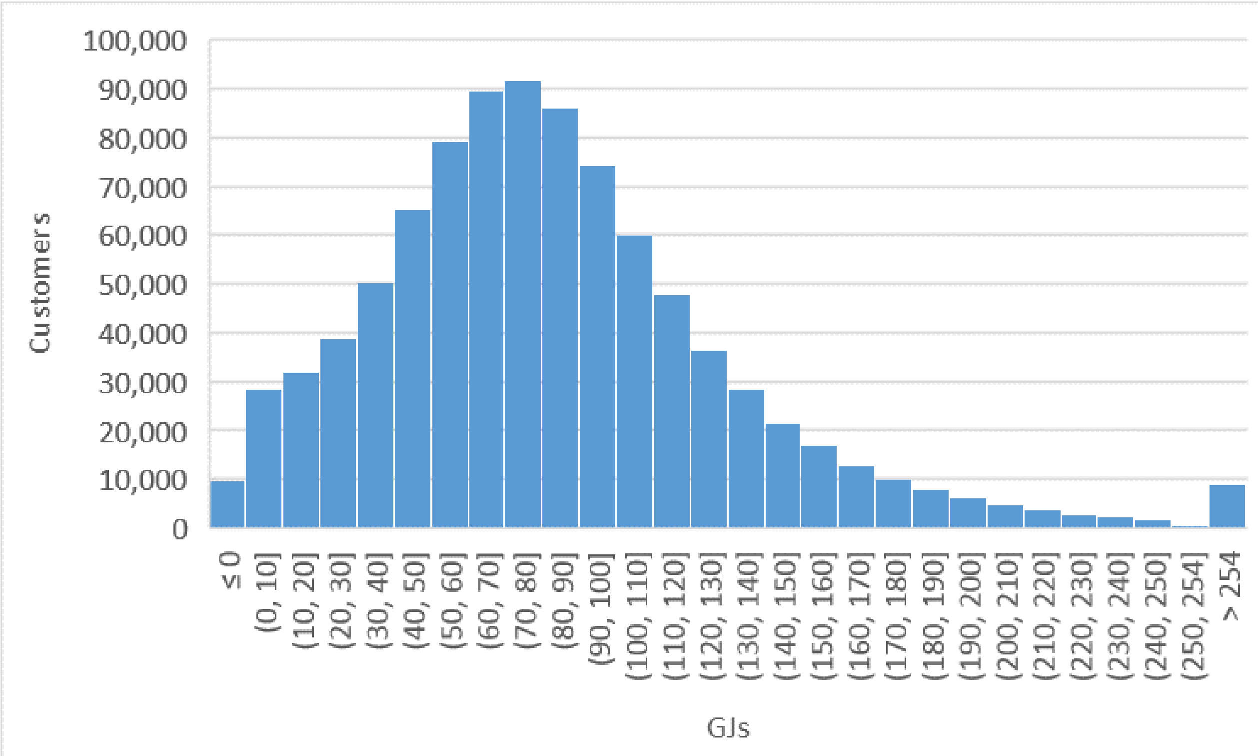
	FEI Energy (Pjs)(1)											
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
RS 1	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5	79.2	80.8
RS 2	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0	29.0	29.1	29.6	30.2
RS 3	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.8	21.5
RS 23	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6	9.3	9.5	9.4	9.6
Industrial	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	87.7	90.6
Sub-Total	202.1	199.2	201.9	206.6	209.7	206.3	205.7	209.5	219.3	223.3	226.7	232.6
NGT	0.0	0.0	0.0	0.1	0.2	0.3	0.8	1.1	1.3	1.8	2.3	2.8
Total	202.1	199.2	201.9	206.7	209.9	206.6	206.5	210.6	220.6	225.0	229.0	235.4

Table A2-2: FEI 2017 Industrial Forecast Demand by Region[2]

Industrial	2019 Forecast Demand By Region
Mainland	68.0
Vancouver Island	22.4
Whistler	0.1
Total	**90.6**

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

1 **Figure A2-1: FEI Residential Customers Normalized UPC in 2017**



2

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. 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 Commission Order G-131-14.

3.1 *AMALGAMATED NET CUSTOMERS*

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	842,919	846,375	849,539	857,592	870,980	880,331	866,852	883,371	892,830	909,727
Actual	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885
Error = (ACT-FCST)	-6,336	-2,069	3,953	2,811	-16,930	-17,142	6,809	2,798	4,698	1,158
Percent Error = (Error/ACT)	-0.8%	-0.2%	0.5%	0.3%	-2.0%	-2.0%	0.8%	0.3%	0.5%	0.1%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	83,957	84,667	86,383	87,262	85,482	85,627	81,923	84,651	85,667	87,712
Actual	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076	86,074	86,973
Error = (ACT-FCST)	662	398	-1,190	-1,558	-4,359	-3,175	1,702	425	407	-739
Percent Error = (Error/ACT)	0.8%	0.5%	-1.4%	-1.8%	-5.4%	-3.9%	2.0%	0.5%	0.5%	-0.8%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	5,116	5,316	5,671	5,785	5,553	5,597	5,147	5,117	5,035	5,354
Actual	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,441
Error = (ACT-FCST)	344	113	-205	-334	-333	-463	22	184	154	87
Percent Error = (Error/ACT)	6.3%	2.1%	-3.8%	-6.1%	-6.4%	-9.0%	0.4%	3.5%	3.0%	1.6%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	1,423	1,426	1,319	1,328	1,526	1,586	1,634	1,552	1,670	1,760
Actual	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,712
Error = (ACT-FCST)	-117	-78	87	105	-6	-57	-112	172	133	-48
Percent Error = (Error/ACT)	-9.0%	-5.8%	6.2%	7.3%	-0.4%	-3.7%	-7.4%	10.0%	7.4%	-2.8%

3.2 AMALGAMATED NET CUSTOMER ADDITIONS

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	14,603	9,827	7,012	7,724	8,984	9,352	6,647	9,710	9,461	11,522
Actual	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357
Error = (ACT-FCST)	-3,282	-2,104	2,174	-813	-2,613	-213	3,825	2,798	1,898	1,835
Percent Error = (Error/ACT)	-29.0%	-27.2%	23.7%	-11.8%	-41.0%	-2.3%	36.5%	22.4%	16.7%	13.7%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	796	618	830	877	145	145	411	1,026	1,026	1,318
Actual	1,330	446	128	511	577	1,329	1,173	1,450	998	899
Error = (ACT-FCST)	534	-172	-702	-366	432	1,184	762	424	-28	-419
Percent Error = (Error/ACT)	40.2%	-38.6%	-548.4%	-71.6%	74.9%	89.1%	65.0%	29.2%	-2.8%	-46.6%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	14	14	105	114	44	44	4	-52	-51	26
Actual	171	-31	37	-16	-104	-86	35	132	-112	252
Error = (ACT-FCST)	157	-45	-68	-130	-148	-130	31	184	-61	226
Percent Error = (Error/ACT)	91.8%	145.2%	-183.8%	812.5%	142.3%	151.2%	88.6%	139.4%	54.5%	89.7%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	70	53	9	9	60	60	57	30	30	18
Actual	3	42	58	27	88	9	-7	202	79	-91
Error = (ACT-FCST)	-67	-11	49	18	28	-51	-64	172	49	-109
Percent Error = (Error/ACT)	-2233.3%	-26.2%	84.5%	66.7%	31.8%	-566.7%	914.3%	85.1%	62.0%	119.8%

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	92.4	87.7	87.9	86.5	86.3	85.2	86.0	83.1	81.6	82.2
Actual	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8
Error = (ACT-FCST)	(3.6)	1.4	0.5	(0.2)	1.3	(0.5)	(1.8)	1.3	5.9	3.7
Percent Error = (Error/ACT)	-4.1%	1.6%	0.6%	-0.2%	1.5%	-0.6%	-2.1%	1.5%	6.7%	4.3%

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	325.4	309.0	320.5	320.2	315.0	314.5	340.0	333.7	329.5	328.4
Actual	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8
Error = (ACT-FCST)	(7.2)	16.1	(4.3)	(2.5)	26.2	17.1	(9.4)	(1.1)	9.6	8.3
Percent Error = (Error/ACT)	-2.3%	5.0%	-1.4%	-0.8%	7.7%	5.2%	-2.8%	-0.3%	2.8%	2.5%

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	3,573	3,164	3,496	3,487	3,450	3,435	3,872	3,754	3,593	3,488
Actual	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692
Error = (ACT-FCST)	(34)	316	(11)	101	234	175	(299)	(167)	128	205
Percent Error = (Error/ACT)	-1.0%	9.1%	-0.3%	2.8%	6.4%	4.8%	-8.4%	-4.7%	3.4%	5.5%

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	4,850	4,391	4,680	4,680	4,901	4,927	5,546	5,309	5,382	5,227
Actual	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361
Error = (ACT-FCST)	(152)	495	170	458	337	222	(286)	(135)	(103)	133
Percent Error = (Error/ACT)	-3.2%	10.1%	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.6%	-2.0%	2.5%

3.4 AMALGAMATED DEMAND

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	77.2	73.8	74.3	73.8	74.7	74.6	74.2	73.1	72.5	74.3
Actual	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5
Error = (ACT-FCST)	(3.5)	1.0	0.7	0.1	(0.2)	(1.9)	(1.0)	1.0	5.4	3.3
Percent Error = (Error/ACT)	-4.7%	1.3%	0.9%	0.1%	-0.3%	-2.6%	-1.4%	1.3%	6.9%	4.2%
Abs. Percent Error	4.7%	1.3%	0.9%	0.1%	0.3%	2.6%	1.4%	1.3%	6.9%	4.2%

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	27.1	26.1	27.5	27.7	26.9	26.9	27.7	28.1	28.0	28.5
Actual	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0	29.0	29.1
Error = (ACT-FCST)	(0.5)	1.4	(0.6)	(0.6)	0.7	0.1	(0.2)	(0.1)	1.0	0.6
Percent Error = (Error/ACT)	-1.9%	5.1%	-2.2%	-2.2%	2.5%	0.4%	-0.7%	-0.4%	3.4%	2.0%

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	18.2	16.8	19.6	19.9	19.1	19.1	19.9	19.2	18.1	18.7
Actual	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2	19.4	19.7
Error = (ACT-FCST)	0.7	2.2	(0.6)	(0.4)	0.2	(0.4)	(1.4)	(0.0)	1.3	1.0
Percent Error = (Error/ACT)	3.7%	11.6%	-3.2%	-2.1%	1.0%	-2.1%	-7.6%	-0.2%	6.7%	5.2%

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	6.6	6.1	6.1	6.2	7.2	7.5	8.7	8.3	9.0	9.2
Actual	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6	9.3	9.5
Error = (ACT-FCST)	(0.4)	0.4	0.5	1.2	0.6	0.4	(0.7)	0.3	0.3	0.4
Percent Error = (Error/ACT)	-6.5%	6.2%	7.6%	16.2%	7.7%	5.1%	-8.7%	3.5%	3.2%	3.9%

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Commercial										
Forecast	51.9	49.0	53.2	53.8	53.2	53.5	56.3	55.6	55.1	56.4
Actual	51.7	53.0	52.5	54.0	54.7	53.6	54.0	55.8	57.7	58.3
Error = (ACT-FCST)	(0.2)	4.0	(0.7)	0.2	1.5	0.1	(2.3)	0.2	2.6	2.0
Percent Error = (Error/ACT)	-0.4%	7.5%	-1.3%	0.4%	2.7%	0.2%	-4.3%	0.3%	4.5%	3.4%
Abs. Percent Error	0.4%	7.5%	1.3%	0.4%	2.7%	0.2%	4.3%	0.3%	4.5%	3.4%

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Industrial*										
Forecast	75.1	71.9	73.2	71.3	72.1	72.1	86.2	76.4	78.1	82.1
Actual	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4
Error = (ACT-FCST)	1.5	(0.5)	1.2	7.5	8.5	8.0	(7.6)	3.2	5.6	5.3
Percent Error = (Error/ACT)	2.0%	-0.7%	1.6%	9.5%	10.5%	10.0%	-9.7%	4.0%	6.7%	6.0%
Abs. Percent Error	2.0%	0.7%	1.6%	9.5%	10.5%	10.0%	9.7%	4.0%	6.7%	6.0%

Demand,PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
FEI										
Forecast	204.2	194.7	200.7	198.9	200.0	200.2	216.7	205.2	205.7	212.8
Actual	202.0	199.2	201.9	206.7	209.8	206.4	205.8	209.5	219.3	223.3
Error = (ACT-FCST)	(2.2)	4.5	1.2	7.8	9.8	6.2	(10.9)	4.3	13.6	10.5
Percent Error = (Error/ACT)	-1.1%	2.3%	0.6%	3.8%	4.7%	3.0%	-5.3%	2.1%	6.2%	4.7%
Abs. Percent Error	1.1%	2.3%	0.6%	3.8%	4.7%	3.0%	5.3%	2.1%	6.2%	4.7%

* Does not include NGT and Burrard Thermal

3.5 MAINLAND NET CUSTOMERS

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	755,539	755,803	757,161	762,460	773,231	780,005	768,622	780,972	787,836	799,732
Actual	748,913	753,735	760,559	765,553	759,712	766,668	774,083	782,914	790,562	798,917
Error = (ACT-FCST)	(6,626)	(2,068)	3,398	3,093	(13,519)	(13,337)	5,461	1,942	2,726	(815)
Percent Error = (Error/ACT)	-0.9%	-0.3%	0.4%	0.4%	-1.8%	-1.7%	0.7%	0.2%	0.3%	-0.1%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	75,037	75,685	77,204	77,954	76,126	76,175	72,922	75,315	76,166	77,597
Actual	75,701	75,986	76,028	76,437	72,235	73,480	74,464	75,451	76,326	77,047
Error = (ACT-FCST)	664	301	(1,176)	(1,517)	(3,891)	(2,695)	1,542	136	160	(550)
Percent Error = (Error/ACT)	0.9%	0.4%	-1.5%	-2.0%	-5.4%	-3.7%	2.1%	0.2%	0.2%	-0.7%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	4,514	4,715	5,083	5,191	4,962	5,002	4,577	4,560	4,497	4,667
Actual	4,869	4,841	4,882	4,863	4,675	4,598	4,625	4,671	4,605	4,867
Error = (ACT-FCST)	355	126	(201)	(328)	(287)	(404)	48	111	108	200
Percent Error = (Error/ACT)	7.3%	2.6%	-4.1%	-6.7%	-6.1%	-8.8%	1.0%	2.4%	2.3%	4.1%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	1,423	1,426	1,319	1,328	1,526	1,586	1,634	1,552	1,582	1,609
Actual	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,573	1,614	1,546
Error = (ACT-FCST)	(117)	(78)	87	105	(6)	(57)	(112)	21	32	(63)
Percent Error = (Error/ACT)	-9.0%	-5.8%	6.2%	7.3%	-0.4%	-3.7%	-7.4%	1.3%	2.0%	-4.1%

3.6 MAINLAND NET CUSTOMER ADDITIONS

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	11,094	6,410	4,777	4,983	6,507	6,774	4,594	6,889	6,863	8,250
Actual	7,959	4,822	6,824	4,994	4,475	6,956	7,415	8,831	7,648	8,355
Error = (ACT-FCST)	(3,135)	(1,588)	2,047	11	(2,032)	182	2,821	1,942	785	105
Percent Error = (Error/ACT)	-39.4%	-32.9%	30.0%	0.2%	-45.4%	2.6%	38.0%	22.0%	10.3%	1.3%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	626	480	713	750	49	49	331	851	851	1,072
Actual	1,122	285	42	409	325	1,245	984	987	875	721
Error = (ACT-FCST)	496	(195)	(671)	(341)	276	1,196	653	136	24	(351)
Percent Error = (Error/ACT)	44.2%	-68.4%	-1597.6%	-83.4%	84.9%	96.1%	66.4%	13.7%	2.7%	-48.7%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	8	7	101	108	40	40	-	(65)	(64)	(1)
Actual	169	(28)	41	(19)	(144)	(77)	27	46	(66)	262
Error = (ACT-FCST)	161	(35)	(60)	(127)	(184)	(117)	27	111	(2)	263
Percent Error = (Error/ACT)	95.3%	125.0%	-146.3%	668.4%	127.8%	151.9%	100.0%	241.3%	3.0%	100.4%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	70	53	9	9	60	60	57	30	30	18
Actual	3	42	58	27	88	9	(7)	51	41	(68)
Error = (ACT-FCST)	(67)	(11)	49	18	28	(51)	(64)	21	11	(86)
Percent Error = (Error/ACT)	-2233.3%	-26.2%	84.5%	66.7%	31.8%	-566.7%	914.3%	41.2%	26.8%	126.5%

3.7 MAINLAND NORMALIZED USE PER CUSTOMER

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	96.1	91.1	91.7	90.3	90.8	89.9	90.7	88.1	86.3	86.2
Actual	92.5	93.3	92.6	90.4	92.2	89.3	88.8	88.7	92.0	90.4
Error = (ACT-FCST)	(3.6)	2.2	0.9	0.1	1.4	(0.6)	(1.9)	0.6	5.7	4.2
Percent Error = (Error/ACT)	-3.9%	2.4%	1.0%	0.1%	1.5%	-0.7%	-2.1%	0.7%	6.2%	4.6%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	322	303	318	318	308	306	334	329	329	327
Actual	312	321	311	314	338	330	330	330	338	335
Error = (ACT-FCST)	(10)	17	(7)	(4)	30	23	(3)	1	10	8
Percent Error = (Error/ACT)	-3.1%	5.4%	-2.1%	-1.3%	8.8%	7.0%	-1.0%	0.2%	2.8%	2.4%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	3,429	2,976	3,346	3,347	3,334	3,316	3,769	3,599	3,537	3,517
Actual	3,420	3,372	3,370	3,484	3,566	3,517	3,529	3,524	3,658	3,625
Error = (ACT-FCST)	(9)	396	24	137	232	201	(240)	(75)	121	108
Percent Error = (Error/ACT)	-0.3%	11.7%	0.7%	3.9%	6.5%	5.7%	-6.8%	-2.1%	3.3%	3.0%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	4,850	4,391	4,680	4,680	4,901	4,927	5,546	5,309	5,348	5,197
Actual	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,157	5,304	5,388
Error = (ACT-FCST)	(152)	495	170	458	337	222	(286)	(152)	(44)	191
Percent Error = (Error/ACT)	-3.2%	10.1%	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.9%	-0.8%	3.5%

3.8 MAINLAND NORMALIZED DEMAND

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	72.0	68.5	69.2	68.6	69.9	69.8	69.5	68.5	67.7	68.6
Actual	68.8	70.0	70.0	68.9	69.8	68.1	68.5	68.9	72.3	71.8
Error = (ACT-FCST)	(3.2)	1.5	0.9	0.4	(0.1)	(1.7)	(1.0)	0.4	4.6	3.2
Percent Error = (Error/ACT)	-4.6%	2.1%	1.2%	0.5%	-0.2%	-2.5%	-1.5%	0.5%	6.4%	4.5%
ABS	4.6%	2.1%	1.2%	0.5%	0.2%	2.5%	1.5%	0.5%	6.4%	4.5%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	24.0	22.9	24.4	24.6	23.4	23.3	24.2	24.7	24.9	25.2
Actual	23.4	24.3	23.6	23.9	24.3	23.9	24.5	24.6	25.6	25.7
Error = (ACT-FCST)	(0.6)	1.4	(0.8)	(0.7)	0.9	0.6	0.2	(0.0)	0.7	0.5
Percent Error = (Error/ACT)	-2.7%	5.7%	-3.2%	-3.0%	3.6%	2.5%	0.9%	-0.2%	2.7%	2.0%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	15.5	14.0	16.8	17.2	16.5	16.5	17.3	16.4	16.0	16.4
Actual	16.3	16.5	16.4	16.9	16.7	16.3	16.3	16.5	16.8	17.3
Error = (ACT-FCST)	0.8	2.5	(0.4)	(0.3)	0.2	(0.2)	(1.0)	0.0	0.8	0.9
Percent Error = (Error/ACT)	4.9%	15.2%	-2.4%	-1.8%	1.2%	-1.2%	-6.1%	0.3%	5.0%	5.4%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast	6.6	6.1	6.1	6.2	7.2	7.5	8.7	8.3	8.4	8.3
Actual	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.0	8.4	8.6
Error = (ACT-FCST)	(0.4)	0.4	0.5	1.2	0.6	0.4	(0.7)	(0.3)	-	0.3
Percent Error = (Error/ACT)	-6.5%	6.2%	7.6%	16.2%	7.7%	5.1%	-8.7%	-3.3%	0.0%	3.1%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Commercial										
Forecast	46.1	43.0	47.3	48.0	47.1	47.3	50.2	49.3	49.3	49.9
Actual	45.9	47.3	46.6	48.2	48.8	48.1	48.8	49.1	50.8	51.6
Error = (ACT-FCST)	(0.2)	4.3	(0.7)	0.2	1.7	0.8	(1.5)	(0.3)	1.5	1.7
Percent Error = (Error/ACT)	-0.5%	9.1%	-1.4%	0.4%	3.4%	1.6%	-3.0%	-0.5%	3.0%	3.3%

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. 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 Commission Order G-131-14. Tables in Sections 3.10 through 3.17 use this mapped data for historical calculations.

3.10 *VANCOUVER ISLAND NET CUSTOMERS*

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	85,256	88,394	90,106	92,811	95,460	98,023	95,858	99,921	102,458	107,314
Actual	85,536	88,321	90,671	92,554	92,067	94,173	97,162	100,747	104,358	109,259
Error = (ACT-FCST)	280	(73)	565	(257)	(3,393)	(3,850)	1,304	826	1,900	1,945
Percent Error = (Error/ACT)	0.3%	-0.1%	0.6%	-0.3%	-3.7%	-4.1%	1.3%	0.8%	1.8%	1.8%

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	8,666	8,718	8,917	9,042	9,081	9,172	8,710	9,047	9,209	9,808
Actual	8,658	8,815	8,900	8,981	8,613	8,691	8,875	9,330	9,459	9,629
Error = (ACT-FCST)	(8)	97	(17)	(61)	(468)	(481)	165	283	250	(179)
Percent Error = (Error/ACT)	-0.09%	1.10%	-0.19%	-0.68%	-5.43%	-5.53%	1.86%	3.03%	2.64%	-1.86%

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	545	539	527	532	532	536	509	497	479	647
Actual	533	527	525	527	484	476	484	582	531	517
Error = (ACT-FCST)	(12)	(12)	(2)	(5)	(48)	(60)	(25)	85	52	(130)
Percent Error = (Error/ACT)	-2.25%	-2.28%	-0.38%	-0.95%	-9.92%	-12.61%	-5.17%	14.60%	9.79%	-25.15%

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									83	141
Actual								141	175	152
Error = (ACT-FCST)								141	92	11
Percent Error = (Error/ACT)									52.57%	7.24%

3.11 *VANCOUVER ISLAND NET CUSTOMER ADDITIONS*

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	3,479	3,367	2,200	2,705	2,463	2,564	2,001	2,759	2,537	3,188
Actual	3,326	2,785	2,350	1,883	1,845	2,106	2,989	3,583	3,611	4,901
Error = (ACT-FCST)	(153)	(582)	150	(822)	(618)	(458)	988	824	1074	1713
Percent Error = (Error/ACT)	-4.6%	-20.9%	6.4%	-43.7%	-33.5%	-21.7%	33.1%	23.0%	29.8%	35.0%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	165	128	116	125	91	91	71	171	171	239
Actual	197	157	85	81	251	78	184	453	129	170
Error = (ACT-FCST)	32	29	(31)	(44)	160	(13)	113	282	(42)	(69)
Percent Error = (Error/ACT)	16.3%	18.3%	-36.4%	-54.1%	63.8%	-16.4%	61.1%	62.2%	-32.6%	-40.6%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	6	4	4	5	4	4	4	13	13	32
Actual	2	(6)	(2)	2	39	(8)	8	98	(51)	(14)
Error = (ACT-FCST)	(4)	(10)	(6)	(3)	35	(12)	4	85	(64)	(46)
Percent Error = (Error/ACT)	-200.0%	166.7%	300.0%	-150.0%	89.7%	150.0%	50.0%	86.6%	125.5%	328.6%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									-	-
Actual								141	34	(23)
Error = (ACT-FCST)								141	34	(23)
Percent Error = (Error/ACT)									100.0%	100.0%

3.12 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	59.3	58.6	55.0	54.9	48.6	46.9	45.0	44.0	45.1	51.3
Actual	56.1	53.5	52.5	51.8	49.5	47.3	47.1	50.5	52.6	51.5
Error = (ACT-FCST)	(3.2)	(5.1)	(2.5)	(3.1)	0.9	0.4	2.1	6.5	7.5	0.3
Percent Error = (Error/ACT)	-5.7%	-9.5%	-4.8%	-6.0%	1.8%	0.8%	4.5%	12.9%	14.3%	0.5%

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	353.0	354.0	340.0	337.0	365.0	372.0	390.0	372.0	334.0	322.8
Actual	365.0	361.0	351.0	345.0	369.0	344.0	328.0	346.0	343.0	344.8
Error = (ACT-FCST)	12.0	7.0	11.0	8.0	4.0	(28.0)	(62.0)	(26.0)	9.0	22.0
Percent Error = (Error/ACT)	3.3%	1.9%	3.1%	2.3%	1.1%	-8.1%	-18.9%	-7.5%	2.6%	6.4%

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	6,499	6,454	6,295	6,349	6,351	6,398	5,896	5,187	4,031	3,069
Actual	4,488	4,421	4,435	4,460	4,820	4,431	3,901	3,894	4,060	4,181
Error = (ACT-FCST)	(2011)	(2033)	(1860)	(1889)	(1531)	(1967)	(1995)	(1293)	29	1112
Percent Error = (Error/ACT)	-44.8%	-46.0%	-41.9%	-42.4%	-31.8%	-44.4%	-51.1%	-33.2%	0.7%	26.6%

UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									5,996.2	5,635.7
Actual								5,636.0	5,052.0	5,157.5
Error = (ACT-FCST)									(944.2)	(478.2)
Percent Error = (Error/ACT)									-18.7%	-9.3%

3.13 VANCOUVER ISLAND NORMALIZED DEMAND

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	4.9	5.1	4.9	5.0	4.6	4.5	4.3	4.3	4.6	5.4
Actual	4.7	4.6	4.7	4.7	4.5	4.4	4.5	5.0	5.4	5.5
Error = (ACT-FCST)	(0.2)	(0.5)	(0.2)	(0.3)	(0.1)	(0.1)	0.2	0.6	0.8	0.1
Percent Error = (Error/ACT)	-4.3%	-10.9%	-4.3%	-6.4%	-2.2%	-2.3%	4.4%	12.9%	15.6%	1.5%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	3.0	3.1	3.0	3.0	3.3	3.4	3.3	3.3	3.0	3.1
Actual	3.1	3.2	3.1	3.1	3.1	3.0	2.9	3.2	3.2	3.3
Error = (ACT-FCST)	0.1	0.1	0.1	0.1	(0.2)	(0.4)	(0.5)	(0.2)	0.2	0.2
Percent Error = (Error/ACT)	3.2%	2.5%	3.2%	1.6%	-5.1%	-14.9%	-16.0%	-4.7%	6.3%	5.4%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.5	1.9	2.0
Actual	2.4	2.4	2.3	2.3	2.3	2.1	1.9	2.4	2.2	2.1
Error = (ACT-FCST)	(0.1)	(0.1)	(0.2)	(0.2)	(0.1)	(0.3)	(0.5)	(0.1)	0.3	0.1
Percent Error = (Error/ACT)	-4.2%	-5.1%	-6.8%	-8.1%	-2.6%	-13.7%	-28.3%	-5.0%	13.6%	6.5%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									0.5	0.8
Actual								0.5	0.8	0.9
Error = (ACT-FCST)								(0.5)	(0.3)	(0.1)
Percent Error = (Error/ACT)									-37.50%	-9.16%

Demand, PJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Commercial										
Forecast	5.5	5.5	5.5	5.6	5.7	5.8	5.7	5.9	5.4	5.9
Actual	5.5	5.5	5.5	5.4	5.5	5.1	4.8	6.2	6.2	6.3
Error = (ACT-FCST)	-	(0.0)	(0.1)	(0.1)	(0.2)	(0.7)	(1.0)	0.3	0.8	0.4
Percent Error = (Error/ACT)	0.0%	-0.7%	-1.1%	-2.6%	-4.0%	-14.4%	-20.8%	4.4%	12.9%	6.3%

3.14 WHISTLER NET CUSTOMERS

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	2,124	2,178	2,272	2,321	2,289	2,303	2,372	2,478	2,536	2,681
Actual	2,134	2,250	2,262	2,296	2,271	2,348	2,416	2,508	2,608	2,709
Error = (ACT-FCST)	10	72	-10	-25	-18	45	44	30	72	28
Percent Error = (Error/ACT)	0.5%	3.2%	-0.4%	-1.1%	-0.8%	1.9%	1.8%	1.2%	2.8%	1.0%

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	254	264	263	267	275	280	291	289	292	309
Actual	260	263	265	286	274	281	285	295	289	297
Error = (ACT-FCST)	6	-1	2	19	-1	1	-6	6	-3	-12
Percent Error = (Error/ACT)	2.3%	-0.4%	0.8%	6.6%	-0.4%	0.4%	-2.1%	2.0%	-1.0%	-4.0%

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	57	62	61	62	59	59	61	60	59	39
Actual	58	61	59	61	61	60	60	48	53	57
Error = (ACT-FCST)	1	-1	-2	-1	2	1	-1	-12	-6	18
Percent Error = (Error/ACT)	1.7%	-1.6%	-3.4%	-1.6%	3.3%	1.7%	-1.7%	-25.0%	-11.3%	31.6%

Customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									5	10
Actual								10	14	14
Error = (ACT-FCST)								10	9	4
Percent Error = (Error/ACT)									64.3%	28.6%

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	30	50	35	36	14	14	52	62	61	84
Actual	36	116	12	34	51	77	68	92	100	101
Error = (ACT-FCST)	6	66	(23)	(2)	37	63	16	30	39	17
Percent Error = (Error/ACT)	16.7%	56.9%	-191.7%	-5.9%	72.5%	81.8%	23.5%	32.6%	39.0%	16.8%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	5	10	1	2	5	5	9	4	4	7
Actual	11	3	2	21	-	7	5	10	(6)	8
Error = (ACT-FCST)	6	(7)	1	19	(5)	2	(4)	6	(10)	1
Percent Error = (Error/ACT)	54.5%	-233.3%	50.0%	90.5%		28.6%	-80.0%	60.0%	166.7%	11.9%

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast		3		1				-	**-**	**(5)**
Actual	(1)	3		2	(0)	(1)	(0)	(12)	**5**	**4**
Error = (ACT-FCST)		(0)		1				(12)	**5**	**5**
Percent Error = (Error/ACT)		-2.3%		41.1%					**100.0%**	**125.0%**

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									-	-
Actual								10	4	-
Error = (ACT-FCST)								10	4	0
Percent Error = (Error/ACT)									100.0%	

3.16 *WHISTLER NORMALIZED USE PER CUSTOMER*

FEW UPC										
UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1										
Forecast	88.2	90.1	92.1	82.3	104.0	106.3	90.6	79.7	85.1	97.9
Actual	89.9	82.6	99.5	94.7	89.4	87.3	87.6	91.3	97.7	93.5
Error = (ACT-FCST)	2	-8	7	12	-15	-19	-3	12	13	-4
Percent Error = (Error/ACT)	1.9%	-9.1%	7.4%	13.1%	-16.3%	-21.8%	-3.4%	12.7%	12.9%	-4.7%
UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2										
Forecast	431.0	456.0	464.0	430.0	610.0	637.0	464.0	408.0	465.0	792.9
Actual	502.0	427.0	563.0	506.0	429.0	465.0	471.0	660.0	520.2	479.4
Error = (ACT-FCST)	71	-29	99	76	-181	-172	7	252	55	-314
Percent Error = (Error/ACT)	14.1%	-6.8%	17.6%	15.0%	-42.2%	-37.0%	1.5%	38.2%	10.6%	-65.4%
UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3										
Forecast	5,286.0	5,092.0	4,894.0	4,114.0	3,876.0	3,630.0	3,595.0	3,822.0	4,326.0	6,706.9
Actual	4,641.0	4,037.0	4,512.0	4,271.0	3,822.0	4,213.0	4,285.0	5,618.0	5,638.0	5,107.9
Error = (ACT-FCST)	-645	-1,055	-382	157	-54	583	690	1,796	1,312	-1,599
Percent Error = (Error/ACT)	-13.9%	-26.1%	-8.5%	3.7%	-1.4%	13.8%	16.1%	32.0%	23.3%	-31.3%
UPC, GJs	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23										
Forecast									5,888.0	4,328.3
Actual								4,328.0	5,078.0	4,557.0
Error = (ACT-FCST)									-810	229
Percent Error = (Error/ACT)									-16.0%	5.0%

3.17 *WHISTLER NORMALIZED DEMAND*

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 1											
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Actual	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Error = (ACT-FCST)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	(0.0)
Percent Error = (Error/ACT)	3.5%	2.0%	-7.5%	7.5%	12.0%	-14.2%	-21.5%	-1.4%	0.0%	14.6%	-4.1%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 2											
Forecast	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.2
Actual	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.1
Error = (ACT-FCST)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	0.1	0.0	(0.1)
Percent Error = (Error/ACT)	8.3%	15.4%	-9.1%	20.0%	21.4%	-33.3%	-30.8%	0.0%	36.8%	10.0%	-75.0%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 3											
Forecast	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.3
Actual	0.3	0.3	0.2	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	(0.0)	(0.0)	(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Percent Error = (Error/ACT)	-10.3%	-11.1%	-29.2%	-11.1%	3.8%	0.0%	15.4%	15.4%	17.9%	13.3%	3.5%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate Schedule 23											
Forecast										0.03	0.04
Actual									0.03	0.06	0.06
Error = (ACT-FCST)										0.03	0.02
Percent Error = (Error/ACT)										50.9%	32.2%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Commercial											
Forecast	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.6
Actual	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
Error = (ACT-FCST)	(0.0)	(0.0)	(0.1)	0.0	0.0	(0.0)	0.0	0.0	0.2	0.1	(0.1)
Percent Error = (Error/ACT)	-4.9%	-2.5%	-22.9%	0.0%	10.0%	-11.4%	0.0%	10.3%	30.0%	16.8%	-15.0%

3.18 *HOLT'S EXPONENTIAL SMOOTHING (ETS) TEST FORECASTS*

3.18.1 Residential UPC Forecast Results Update

Consistent with the approach taken in Appendix A4 of the Annual Review for 2017 Rates, residential use rates were calculated using the ETS method for the Lower Mainland, Inland and Columbia regions. All other aspects of the forecast were unaltered. The resulting residential demand forecast is shown below.

The Mainland residential demand forecast for 2017 using the existing method was 68.5 PJs. The ETS forecast was almost identical at 68.6 PJs. As a result, the MAPE calculated from 2012 through 2017 remains almost identical for the two methods at 2.6 percent.

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2017 MAPE
Existing	2012	2010	69.9	69.8	0.1%	
	2013	2010	69.8	68.1	2.5%	
	2014	2012	69.5	68.5	1.5%	
	2015	2013	68.5	68.9	0.6%	
	2016	2014	67.7	72.3	6.4%	
	2017	2015	68.5	71.7	4.5%	2.6%
ETS	2012	2010	68.4	69.8	2.1%	
	2013	2010	67.6	68.1	0.7%	
	2014	2012	68.9	68.5	0.6%	
	2015	2013	67.6	68.9	1.9%	
	2016	2014	67.8	72.3	6.2%	
	2017	2015	68.6	71.7	4.4%	2.6%

3.18.2 Commercial UPC Forecast Results Update

Consistent with the approach taken in Appendix A4 of the Annual Review for 2017 Rates, separate commercial use rates were prepared for Rate Schedules 1, 2, 3 and 23 for the Lower Mainland, Inland and Columbia regions using the ETS method. All other aspects of the forecast were unaltered. The resulting commercial demand forecast is shown below.

The Mainland commercial demand forecast for 2017 using the existing method was 49.7 PJs. The ETS forecast was higher at 50.9 PJs and closer to the actual demand of 51.4 PJs. The 2017 error for the ETS method was 1.0 percent compared to 3.3 percent for the Existing method. As a result, the ETS MAPE calculated from 2012 through 2017 is 0.9 percent, while the MAPE for the existing method is 2.5 percent.

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2017 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	
	2016	2014	49.3	50.8	2.9%	
	2017	2015	49.7	51.4	3.3%	2.5%
ETS	2012	2010	48.1	48.8	1.4%	
	2013	2010	48.5	48.1	0.8%	
	2014	2012	48.5	48.8	0.5%	
	2015	2013	49.1	49.1	0.0%	
	2016	2014	49.9	50.8	1.7%	
	2017	2015	50.9	51.4	1.0%	0.9%

3.18.3 Commercial Customer Additions Forecast Update

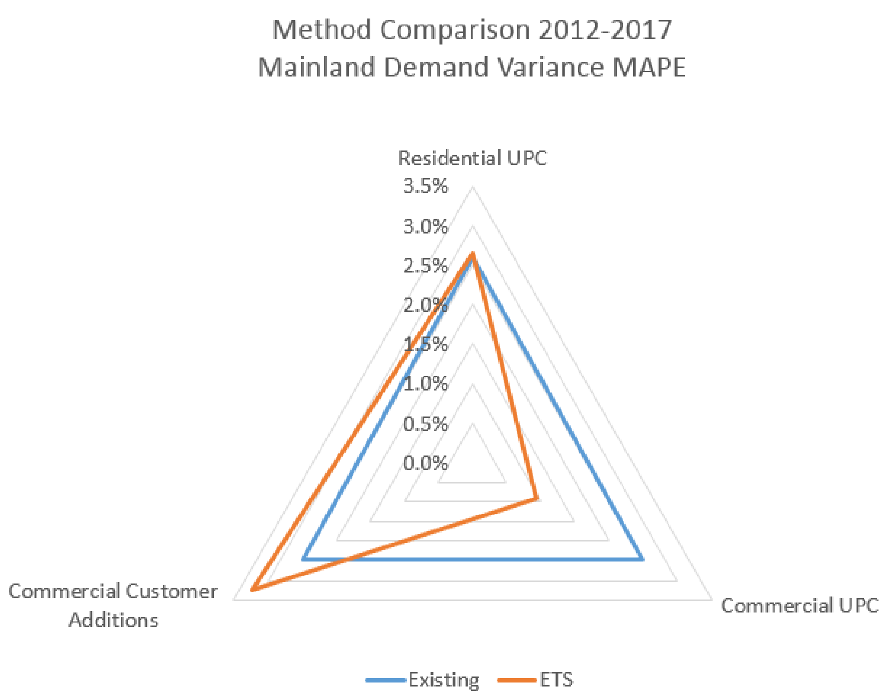
Consistent with the approach taken in Appendix A4 of the Annual Review for 2017 Rates, separate commercial customer additions forecasts were prepared for Rate Schedules 1, 2, 3 and 23 for the Lower Mainland, Inland and Columbia regions using the ETS method. All other aspects of the forecast were unaltered. The resulting commercial demand forecast is shown below.

The Mainland commercial demand forecast for 2017 using the existing method was 49.7 PJs. The ETS forecast was lower at 50.0 PJs. The 2017 error for ETS was 2.9 percent compared to 3.3 percent for the existing method. As a result, the ETS MAPE calculated from 2012 through 2017 is 3.2 percent, while the MAPE for the existing method is less at 2.5 percent.

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2017 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	
	2016	2014	49.3	50.8	2.9%	
	2017	2015	49.7	51.4	3.3%	2.5%
ETS	2012	2010	46.2	48.8	5.3%	
	2013	2010	46.7	48.1	3.0%	
	2014	2012	50.3	48.8	3.1%	
	2015	2013	48.8	49.1	0.5%	
	2016	2014	48.4	50.8	4.7%	
	2017	2015	50.0	51.4	2.9%	3.2%

3.18.4 Evaluation

The following chart compares the performance of the ETS method with the existing method in the three areas under investigation.



The blue triangle represents the MAPE scores for the existing method for each of the three tests. The orange line represents the MAPE scores for ETS. Lines closer to the center of the plot are better. The chart shows that for residential UPC the scores for the two methods are identical. For commercial use rates, the ETS method performed better. For commercial customer additions, the existing method performed better.

Appendix A2-1

HISTORICAL FORECAST AND CONSOLIDATED 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	Time series, normalized historic UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg, historical additions	Prior year customers + customer adds	Time series, normalized historic UPC	Product of Customers and Use Rates
Industrial				Annual survey of industrial customers

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 2019 demand forecast, in the following order:

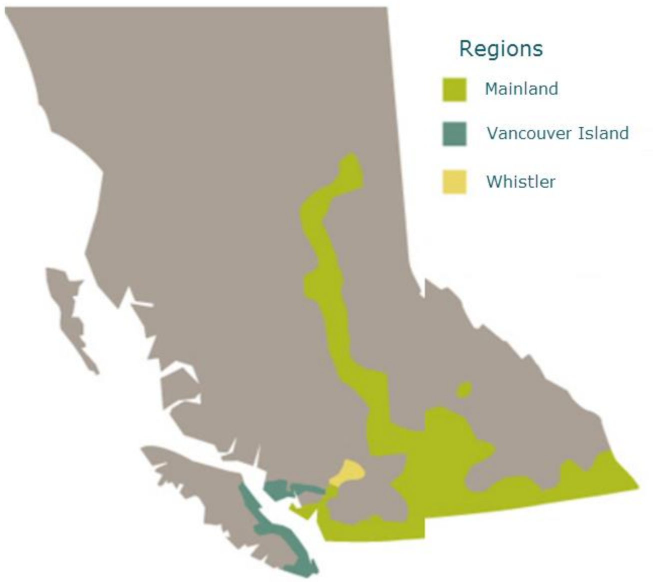
- Residential Customer Additions
- Commercial Customer Additions
- Residential Use Rate
- Commercial Use Rate
- Residential and Commercial Demand Forecast
- Industrial Demand Forecast

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, SEED 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.
- **Seed Year:** The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing.

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.

Industrial	
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 1, 2, 3 and 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 January 17th, 2018 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	2016	2017	2018	2019
SFD	12,278	12,084	11,788	9,481
MFD	29,565	28,916	29,405	24,452
Total	41,843	41,000	41,193	33,933

From the above housing starts forecast, the 2018S SFD growth rate is calculated as follows:

$$2018S\ SFD\ Growth\ Rate = \left(\frac{11{,}788}{12{,}084}\right) - 1 = -2.4\%$$

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

	2018S	2019F
SFD	-2.4%	-19.6%
MFD	1.7%	-16.8%

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 2017 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 2018 are applied to the SFD and MFD proportions for 2018 in column F and G and for 2019 in column I and J.

Table A3-5: FEI Proportions of Actual Account Additions by SFD and MFD

	Internal Split		2017A			2018S			2019F		
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	41%	59%	4,664	1,911	2,753	1,865	2,799	4,664	1,500	2,328	3,828
Inland	85%	15%	3,432	2,932	500	2,860	509	3,369	2,300	423	2,724
Columbia	79%	21%	193	153	40	149	40	189	120	33	153
Revelstoke	94%	6%	66	62	4	60	4	64	48	3	52
Whistler	79%	21%	101	79	22	77	22	99	62	18	80
Vancouver Island	86%	14%	4,901	4,205	696	4,102	708	4,810	3,299	589	3,888
Total FEU			**13,357**	**9,342**	**4,015**	**9,113**	**4,082**	**13,195**	**7,330**	**3,394**	**10,724**

For example, the Lower Mainland 2019F SFD value of 1,500 (column I) is derived as follows:

- Lower Mainland 2017 Internal Split – SFD percentage = 41% (column A)
- Lower Mainland 2017 Actual additions = 4,664 (column C)

$$LML\ 2017A\ Actual\ SFD = 41\%\ \times 4{,}664 = 1{,}911\ (column\ D)$$

$$LML\ 2018S\ Forecast\ SFD =\ -2.4\% \times 1{,}911 = 1{,}865\ (column\ F)$$

$$LML\ 2019F\ Forecast\ SFD = -19.6\% \times 1{,}865 = 1{,}500\ (column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated as an average of the net customers additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland Rate Schedule 2.

Table A3-6: Customer Additions for Lower Mainland Rate Schedule 2

Year	Customers	Customer Additions	Average 2015-2017
2014	51,423		
2015	52,124	701	
2016	52,790	666	
2017	53,320	530	632
2018S	53,952		
2019F	54,584		

The three-year average additions was 632, so 632 net additions are forecast in each of 2018 and 2019.

$$2018S\ Customers = 2017\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2018S = 53{,}952 = 53{,}320 + 632$$

Identical calculations are completed for all regions and all commercial rate schedules.

5. RESIDENTIAL USE RATE

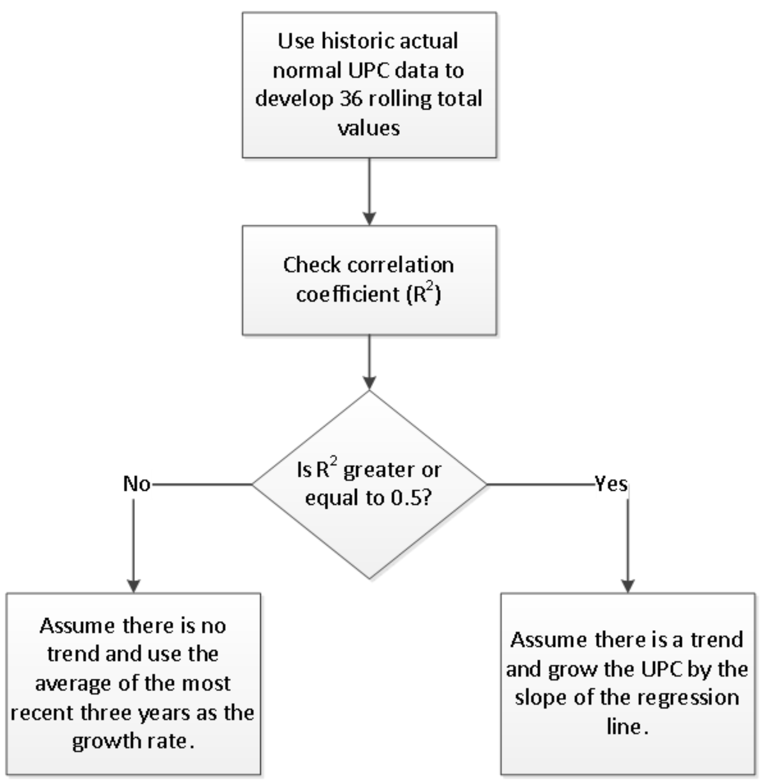
The Residential Demand Forecast is the product of the number of residential customers and the residential use rate. This section describes the method for forecasting the residential use rate.

5.1 MONTHLY WEATHER-NORMALIZED ACTUAL UPCS

FEI develops its residential use rate forecast based on four years of monthly use rates by region and rate class. The monthly UPC values are weather-normalized using the process set out in section 2 above.

The four years of monthly data is used to calculate 36, 12-month rolling UPC sums. These 12-month rolling UPC sums are then plotted and a regression analysis is conducted. If the resulting R^2 value is greater than 50%, then the slope of the regression equation is used to forecast the use rate for the Forecast Year. If the resulting R^2 value is 50% or less, then a three-year average of annual growth rates is used for the forecast.

Figure A3-2: Residential Use Rate Forecast Method



The UPC method for Lower Mainland Rate Schedule 1 (residential) is demonstrated below. The Mainland UPC forecasts are developed from individual forecasts for the Lower Mainland, Inland and Columbia regions. Calculations for the Inland and Columbia regions are identical to the Lower Mainland so are not shown here.

(i) ***Lower Mainland Rate Schedule 1***

The rolling 12-month UPCs for Lower Mainland Rate Schedule 1 were calculated as follows:

Table A3-7: Rolling 12-month UPCs for Lower Mainland Schedule 1

LML RS 1	Monthly UPC	12 month Rolling UPC	Period
Jan-14	14.1		
Feb-14	11.5		
Mar-14	11.0		
Apr-14	8.1		
May-14	4.9		
Jun-14	3.1		
Jul-14	2.8		
Aug-14	2.9		
Sep-14	3.1		
Oct-14	7.3		
Nov-14	10.7		
Dec-14	15.0		94.7
Jan-15	14.9	95.4	1
Feb-15	11.7	95.6	2
Mar-15	10.5	95.0	3
Apr-15	7.6	94.4	4
May-15	4.9	94.5	5
Jun-15	3.8	95.2	6
Jul-15	2.8	95.2	7
Aug-15	2.4	94.8	8
Sep-15	3.1	94.8	9
Oct-15	6.3	93.8	10
Nov-15	10.8	93.8	11
Dec-15	15.3	94.2	12
Jan-16	14.7	94.0	13
Feb-16	13.5	95.8	14
Mar-16	11.5	96.8	15
Apr-16	7.5	96.8	16
May-16	4.7	96.5	17
Jun-16	3.4	96.1	18
Jul-16	2.6	95.8	19
Aug-16	2.6	96.0	20
Sep-16	3.0	95.8	21
Oct-16	7.5	97.0	22
Nov-16	13.1	99.3	23
Dec-16	14.2	98.2	24
Jan-17	14.3	97.7	25
Feb-17	11.4	95.6	26
Mar-17	12.0	96.1	27
Apr-17	8.7	97.3	28
May-17	5.1	97.8	29
Jun-17	3.3	97.7	30
Jul-17	2.6	97.6	31
Aug-17	2.7	97.7	32
Sep-17	3.4	98.2	33
Oct-17	6.6	97.3	34
Nov-17	11.5	95.8	35
Dec-17	14.8	96.4	36

The following summary is developed.

Table A3-8: UPC Calculation Summary

	A	B	C	D	E	F	G	H
1			**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**
2	**Normalized UPC**		94.7	94.2	98.2	96.4		
3	**Avg. Growth Rate**							
4	Growth Rate			-0.6%	4.3%	-1.9%		
5	3 Yr. Avg.					0.6%		
6	**Trend**							
7	Correlation	49%						
8	Slope	0.09						
9	**Forecast**	Use 3 Yr Avg					97.0	97.6

The R^2 (correlation) is 49 percent (row 7), so a three year average is used, as per the flow chart above.

The 2018 seed year forecast in G9 is developed by multiplying one plus the three-year average growth rate (0.6%, row 5) by the 2017 actual UPC (96.4, in F2) as follows:

$$2018S\ UPC = 96.4 \times (1 + 0.6\%) = 97.0\ GJs$$

The 2019 forecast in H9 is developed by multiplying one plus the three year average growth rate (0.6%) by the 2018 seed year forecast UPC in G9 as follows:

$$2019F\ UPC = 97.0 \times (1 + 0.6\%) = 97.6\ GJs$$

6. COMMERCIAL USE RATE

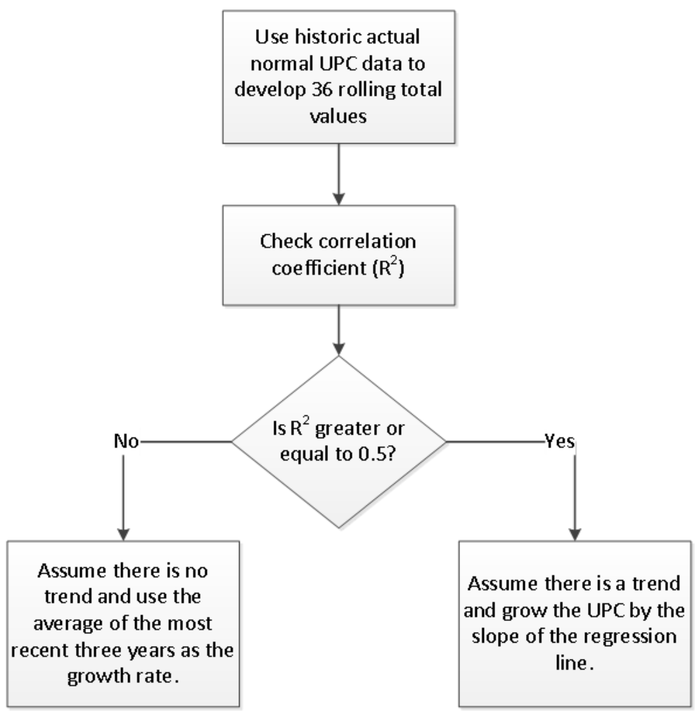
The following sections show how the use rate method works for the commercial forecast. The following method applies to all sub-regions and Rate Schedules 2, 3 and 23.

6.1 MONTHLY WEATHER-NORMALIZED ACTUAL UPCS

FEI develops its commercial use rate forecast based on four years of monthly use rates by region and rate class. The monthly UPC values are weather-normalized using the process set out in section 2 above.

The four years of monthly data is used to calculate 36, 12-month rolling UPC sums. These 12-month rolling UPC sums are then plotted and a regression analysis is conducted. If the resulting R^2 value is greater than 50%, then the slope of the regression equation is used to forecast the use rate for the Forecast Year. If the resulting R^2 value is 50% or less, then a three-year average of annual growth rates is used for the forecast.

Figure A3-3: Commercial Use Rate Forecast Method



The UPC method for Lower Mainland Rate Schedule 3 is demonstrated below. The Mainland UPC forecasts are developed from individual forecasts for the Lower Mainland, Inland and Columbia regions. Calculations for the Inland and Columbia regions are identical to the Lower Mainland so are not shown here.

(i) ***Lower Mainland Rate Schedule 3***

The rolling 12-month UPCs for Lower Mainland Rate Schedule 3 were calculated as follows:

1 **Table A3-9: Rolling 12-month UPCs for Lower Mainland Rate Schedule 3**

LML RS 3	Monthly UPC	12 month Rolling UPC	Period
Jan-14	473.4		
Feb-14	395.6		
Mar-14	395.3		
Apr-14	315.2		
May-14	218.6		
Jun-14	151.9		
Jul-14	135.6		
Aug-14	134.7		
Sep-14	151.0		
Oct-14	277.8		
Nov-14	351.7		
Dec-14	480.5	3,481	
Jan-15	478.8	3,487	1
Feb-15	389.4	3,480	2
Mar-15	377.5	3,463	3
Apr-15	292.3	3,440	4
May-15	222.7	3,444	5
Jun-15	169.1	3,461	6
Jul-15	132.9	3,458	7
Aug-15	121.1	3,445	8
Sep-15	150.1	3,444	9
Oct-15	253.3	3,419	10
Nov-15	359.0	3,427	11
Dec-15	484.8	3,431	12
Jan-16	485.4	3,438	13
Feb-16	450.7	3,499	14
Mar-16	410.2	3,532	15
Apr-16	302.2	3,541	16
May-16	216.4	3,535	17
Jun-16	166.7	3,533	18
Jul-16	138.8	3,539	19
Aug-16	133.6	3,551	20
Sep-16	148.7	3,550	21
Oct-16	286.6	3,583	22
Nov-16	413.4	3,638	23
Dec-16	463.3	3,616	24
Jan-17	482.0	3,613	25
Feb-17	393.7	3,556	26
Mar-17	428.6	3,574	27
Apr-17	334.9	3,607	28
May-17	228.3	3,619	29
Jun-17	160.7	3,613	30
Jul-17	134.3	3,608	31
Aug-17	134.7	3,609	32
Sep-17	160.3	3,621	33
Oct-17	260.2	3,595	34
Nov-17	387.2	3,568	35
Dec-17	486.7	3,592	36

2

The following summary is developed.

Table A3-10: UPC Calculation Summary

	A	B	C	D	E	F	G	H
1			2014	2015	2016	2017	2018S	2019F
2	Normalized UPC		3,481	3,431	3,616	3,592		
3	Avg. Growth Rate							
4	Growth Rate			-1.4%	5.4%	-0.7%		
5	3 Yr. Avg.					1.1%		
6	Trend							
7	Correlation	75%						
8	Annual Slope, GJ	69.4						
9	Forecast	Use Regression					3,661	3,731

The R^2 (correlation) is 75 percent, so a regression is used, as per the flow chart above.

The 2018 seed year forecast is developed by adding the annual slope in B8 (69.4) to the 2017 year end value in F2 (3,592) as follows:

$$2018S\ UPC = 3{,}592 + 69.4 = 3{,}661\ GJs$$

The 2019F forecast is developed by adding the annual slope in B8 (69.4) to the 2018 seed forecast in G9 as follows:

$$2019F\ UPC = 3{,}661 + 69.4 = 3{,}731\ GJs$$

6.2 AMALGAMATION OF UPCS

Once the use rates are seasonalized and developed for each region and each rate schedule (Rate Schedules 1, 2, 3 and 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.

7. UPC METHODS

The following table shows the use rate calculation method used for each region and rate class for the 2018 Forecast.

Table A3-11: Use Rate Calculation Method

Region	Rate Schedule	Method Applied for 2019F
Lower Mainland	RS 1	3 Year Average Model
	RS 2	3 Year Average Model
	RS 3	Regression Model
	RS 23	Regression Model
Inland	RS 1	3 Year Average Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS 23	3 Year Average Model
Columbia	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	Regression Model
	RS 23	Regression Model
Relevestoke	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS 1	Regression Model
Vancouver Island	RS 2	3 Year Average Model
	RS 3	Regression Model
	RS 23	Used average due to lack of historic data points
Whistler	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS 23	Used average due to lack of historic data points

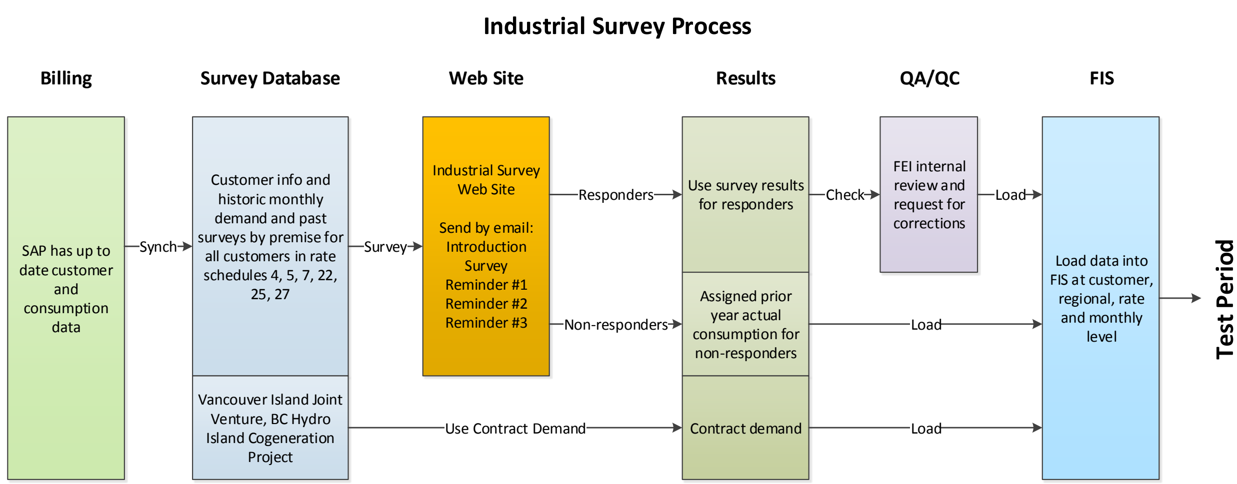
8. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

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.

9. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure A3-4: 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.

9.1 *CREATE THE SURVEY*

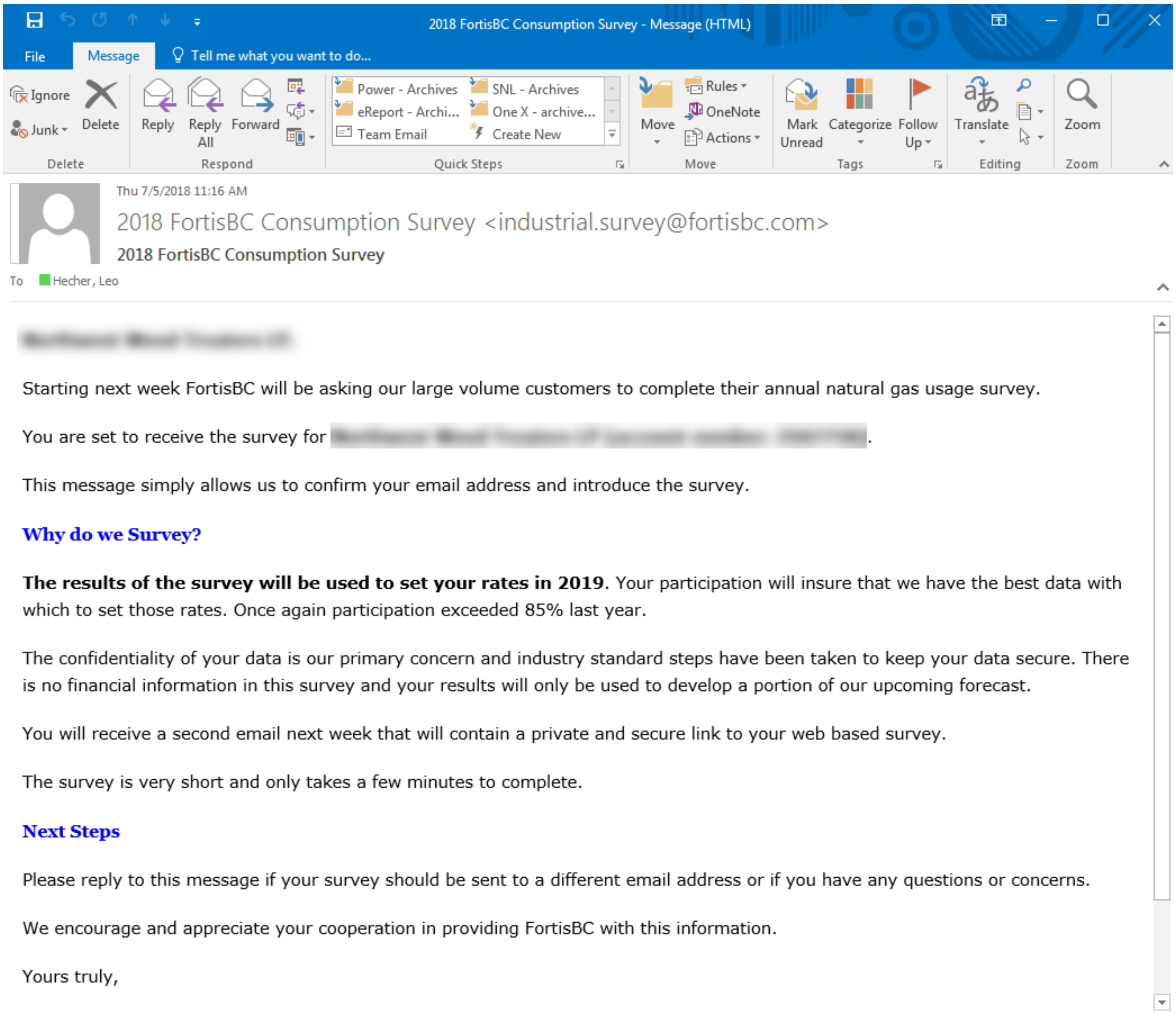
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

9.2 *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 A3-5: 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,

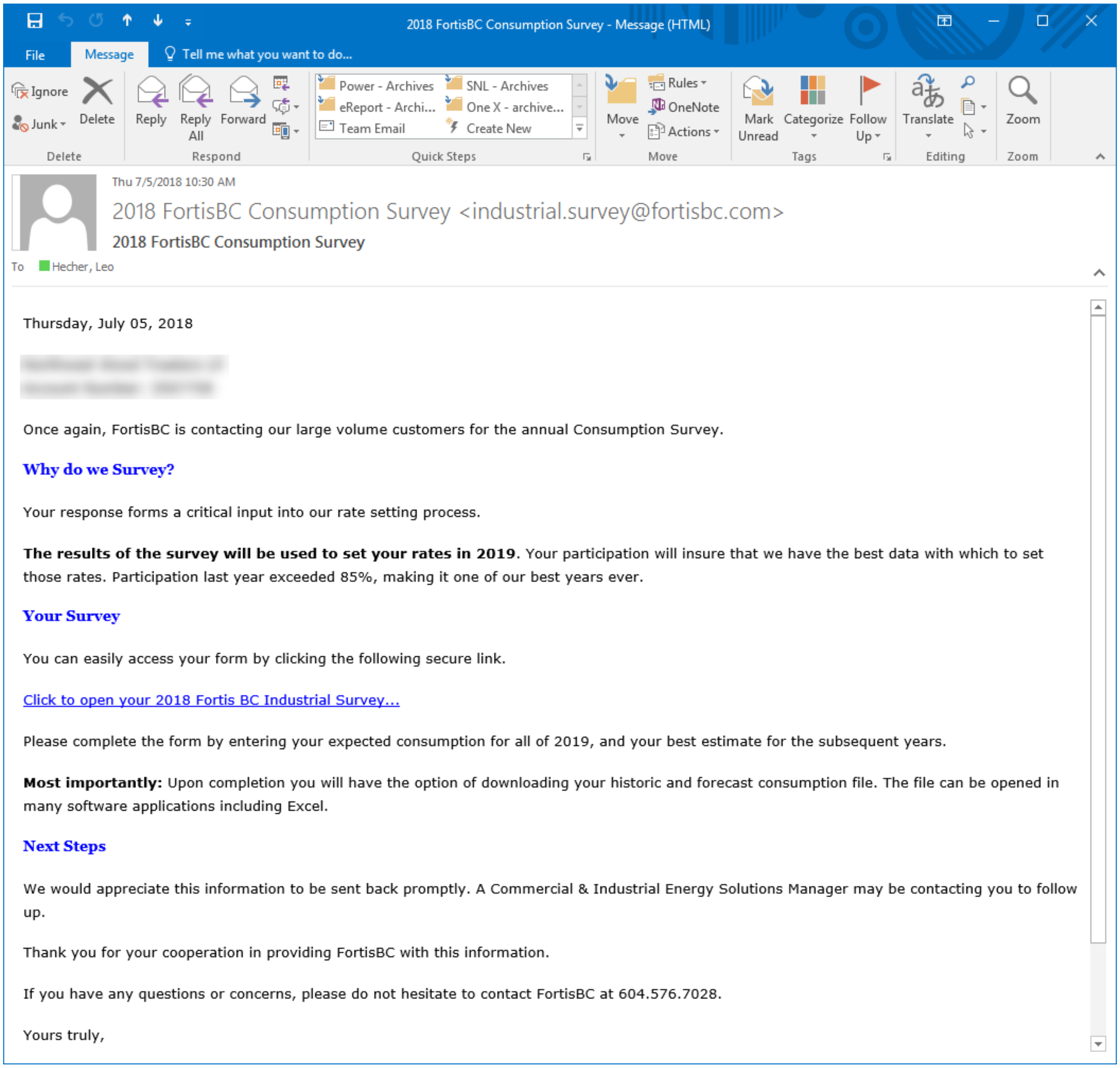
Replies to these emails are used to update the contact and other information in the survey web site.

9.3 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 A3-6: Survey Email Example



Thursday, July 05, 2018

[redacted]

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.

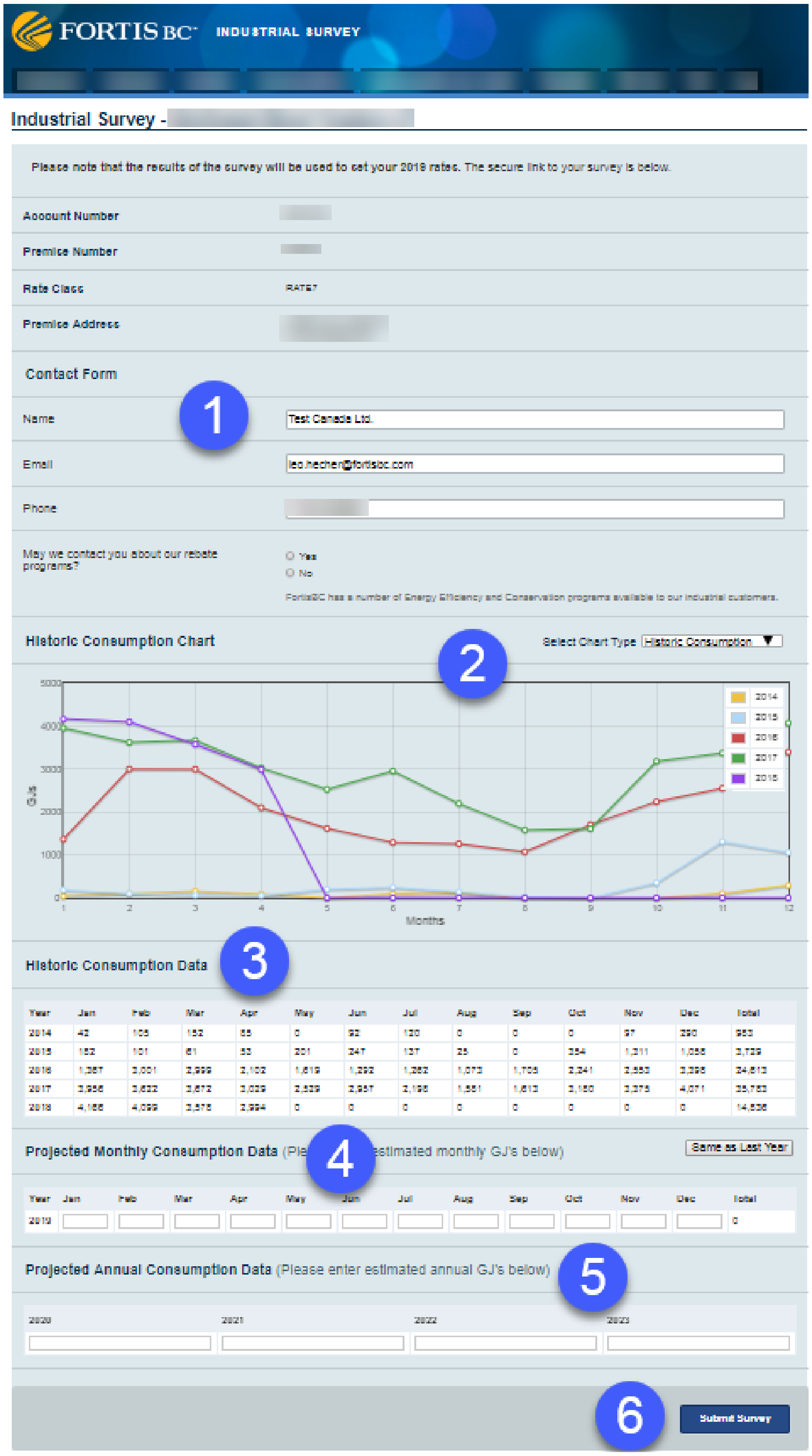
If you have any questions or concerns, please do not hesitate to contact FortisBC at 604.576.7028.

Yours truly,

9.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

Figure A3-7: Survey (Web) Form Example



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	35,753
2018	4,166	4,099	3,575	2,994	0	0	0	0	0	0	0	0	14,836

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2019													0

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.

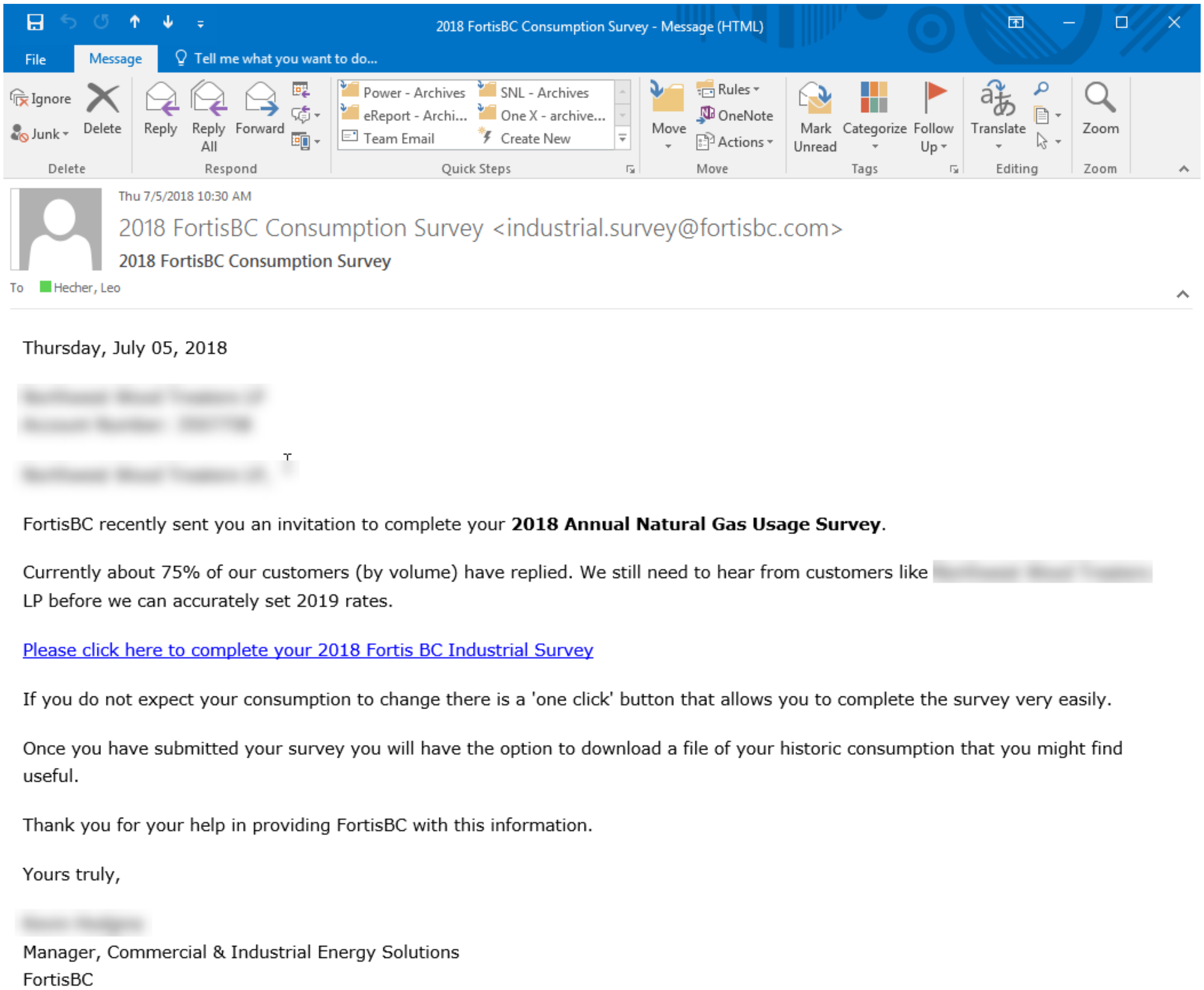
5) Annual forecasts are requested for the remaining 4 years of the survey.

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.

9.5 *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 A3-8: Example of Survey Reminder Email


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

[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

9.6 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 Rate Schedule 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 A3-9: Example of Survey Results Dashboard

9.7 *REVIEWING THE SURVEYS*

Surveys from large volume customers in Rate Schedules 22 and 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.

9.8 *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 synch.

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.

10. 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.

11. HOLTS LINEAR EXPONENTIAL SMOOTHING METHOD

The Holts Linear Exponential Smoothing method (ETS) is implemented as a "wizard" in Excel 2016 and, as a result, 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. Therefore, to demonstrate the key elements of the method, a manual model is required. The model shown below uses accepted practices, but may differ from the optimization methods and strategies used by Microsoft in Excel 2016.

ETS is applied in the same manner to all data sets, including use rates and customers. Given that the illustration of ETS is quite technical (as shown below) and the same for all data sets, FEI has provided one illustration.

Below FEI illustrates how ETS can be used to develop the 2015 forecast UPC for the Lower Mainland. To do this, FEI first introduces the three equations used in ETS and sample Lower Mainland UPC data for purposes of the illustration. FEI then explains how the equations are used with the data to develop the 2015 forecast UPC for the Lower Mainland.

ETS Equations and Sample Data

The three equations used in ETS to develop level, trend and forecast data are shown below:

Table A3-12: ETS Equations

Reference Number	Description	Equation
1	Level forecast at time t	$L_t = \alpha Y_t + (1-\alpha)(L_{t-1} + b_{t-1})$
2	Trend forecast at time t	$b_t = \beta(L_t - L_{t-1}) + (1-\beta)b_{t-1}$
3	Aggregate forecast at time t	$F_{t+m} = L_t + b_t m$

Sample Lower Mainland UPC data (GJ) is provided below, including actual and forecast data from 2004 to 2013 and forecast data for 2014 and 2015. In the discussion below, the 2015 forecast value of 94.04 GJ in row 12, column 6 of the table below will be developed using the three ETS equations above.

Table A3-13: Sample Lower Mainland UPC ETS Calculation

	Alpha	0.500					
	Beta	0.000					
	1	2	3	4	5	6	7
	Date	Actual, Y	Level, L	Trend, b	Period, m	Forecast, F	Error
1	2004	107.81	107.81	(1.10)			
2	2005	103.92	105.32	(1.10)	1	106.71	(2.8)
3	2006	103.16	103.69	(1.10)	1	104.22	(1.1)
4	2007	102.62	102.60	(1.10)	1	102.59	0.0
5	2008	99.51	100.51	(1.10)	1	101.50	(2.0)
6	2009	100.18	99.79	(1.10)	1	99.41	0.8
7	2010	99.81	99.25	(1.10)	1	98.69	1.1
8	2011	97.10	97.63	(1.10)	1	98.15	(1.1)
9	2012	98.60	97.56	(1.10)	1	96.53	2.1
10	2013	96.01	96.24	(1.10)	1	96.46	(0.5)
11	2014				1	95.14	
12	2015				2	94.04	
						SSE	20.33

Establish Starting Values for the Level and Trend

From the ETS equations 1 and 2 above, the level and trend at time “t” rely on level and trend values from the previous time period (t-1).

In this model, FEI has set the starting level to be the same as the 2004 actual (107.81). There are a number of ways of setting the initial trend. Excel uses the SLOPE function over the entire set of actual data and therefore sets the initial trend at -1.1 as shown in the table above.

Once the initial values are set, equations can be entered into each remaining cell in columns 3, 4 and 6, as shown below.

Cell Formulas

The three equations shown above are next entered into columns 3, 4 and 6 of rows 2 through 12. The following view of the above model confirms the correct equations have been entered into the columns. Column 3 uses equation 1, Column 4 uses equation 2 and Column 6 uses equation 3.

Table A3-14: Cell Formulas

	Alpha	**0.5**					
	Beta	**0**					
	1	2	3	4	5	6	7
	Date	**Actual, Y**	**Level, L**	**Trend, b**	**Period, m**	**Forecast, F**	**Error**
1	2004	107.81	=C9	=SLOPE(C9:C18,B9:B18			
2	2005	103.92	=Alpha*C10+(1-Alpha)*(D9+E9)	=Beta*(D10-D9)+(1-Be	1	=D9+E9*F10	=C10-G10
3	2006	103.16	=Alpha*C11+(1-Alpha)*(D10+E10)	=Beta*(D11-D10)+(1-B	1	=D10+E10*F11	=C11-G11
4	2007	102.62	=Alpha*C12+(1-Alpha)*(D11+E11)	=Beta*(D12-D11)+(1-B	1	=D11+E11*F12	=C12-G12
5	2008	99.51	=Alpha*C13+(1-Alpha)*(D12+E12)	=Beta*(D13-D12)+(1-B	1	=D12+E12*F13	=C13-G13
6	2009	100.18	=Alpha*C14+(1-Alpha)*(D13+E13)	=Beta*(D14-D13)+(1-B	1	=D13+E13*F14	=C14-G14
7	2010	99.81	=Alpha*C15+(1-Alpha)*(D14+E14)	=Beta*(D15-D14)+(1-B	1	=D14+E14*F15	=C15-G15
8	2011	97.1	=Alpha*C16+(1-Alpha)*(D15+E15)	=Beta*(D16-D15)+(1-B	1	=D15+E15*F16	=C16-G16
9	2012	98.6	=Alpha*C17+(1-Alpha)*(D16+E16)	=Beta*(D17-D16)+(1-B	1	=D16+E16*F17	=C17-G17
10	2013	96.01	=Alpha*C18+(1-Alpha)*(D17+E17)	=Beta*(D18-D17)+(1-B	1	=D17+E17*F18	=C18-G18
11	2014				1	=$D$18+$E$18*F19	
12	2015				2	=$D$18+$E$18*F20	
						SSE	**=SUM(H10:H18^2)**

Application of Equations 1-3

The values for the level, trend and forecast in row 2 are determined as demonstrated below:

$$Equation\ 1: L_t = 0.50 \times 103.92 + (1 - 0.50)(107.81 - 1.10) = 105.32$$

$$Equation\ 2: b_t = 0.0(105.32 - 107.81) + (1 - 0.0)(-1.10) = -1.10$$

Equation 3 is then used to get the forecast value for 2006 in row 3:

$$Equation\ 3: F_{t+1} = 105.32 - (1.10 \times 1) = 104.22$$

Calculations for columns 3, 4 and 6 are repeated for all rows, through row 10.

Establish the Alpha and Beta Parameters

Once the equations have been entered into the model, values for the alpha and beta parameters can be established. Alpha and beta values must be selected before the forecasts in rows 11 and 12 can be computed. The purpose of the data in rows 1 through 10 is to establish the optimum values of alpha and beta. The data in rows 1 through 10 is referred to as the initialization set.

The process to establish the optimum values of alpha and beta is as follows:

1. Enter values for alpha and beta in the Alpha and Beta cells in the model. In the screen shot above, the values are 0.0 and 0.5, respectively.
2. Values in rows 1 through 10 will be updated using the new parameters.

3. The error calculation in column 7 is the difference between the forecasted value in column 6 and the actual value in column 2. The forecast value in column 6 is from equation 3.

4. Square each error to remove the positive/negative cancellation effect, and then sum the squared errors (SSE).

5. The optimum values for alpha and beta are the pair that result in the minimum SSE over the initialization set.

6. Alpha and beta can be established using values established by Excel, or by step wise trials. Both methods result in the same values, as shown below:

   a) In Excel 2016 the formula "=FORECAST.ETS.STAT" can be used to determine the values of alpha and beta selected by Excel. For the Lower Mainland Rate Schedule 1 data used in this example, the values chosen by Excel are Alpha = 0.05 and Beta = 0.

   b) Alternatively step wise trials can be used. The following chart or "heat map" shows the SSE results of step wise trials for every combination of alpha and beta at 0.05 intervals. Both alpha and beta must be between 0 and 1. The "heat map" shows the sensitivity of the model to the choices of alpha and beta. The chart is colored such that green cells represent lower SSE (better) values than yellow and orange or red cells. Each cell represents a complete model run. The optimum value (20.3) for Alpha=0.50 and Beta=0.0 is black.

Table A3-15: Alpha and Beta Parameters

		ALPHA																				
		0.0	0.05	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90	0.95	1.00
BETA	0.0	51.9	38.9	31.4	27.1	24.5	22.8	21.8	21.0	20.6	20.4	20.3	20.4	20.7	21.1	21.6	22.3	23.1	24.0	25.0	26.2	27.5
	0.05	51.9	37.4	30.0	26.2	24.1	22.8	22.0	21.5	21.1	20.9	20.9	21.0	21.3	21.8	22.3	23.1	23.9	24.9	26.1	27.4	28.8
	0.10	51.9	36.2	29.0	25.8	24.2	23.3	22.6	22.2	21.8	21.6	21.6	21.7	22.0	22.4	23.1	23.8	24.8	25.9	27.2	28.6	30.1
	0.15	51.9	35.0	28.4	25.8	24.7	24.0	23.5	23.0	22.6	22.3	22.2	22.3	22.6	23.1	23.8	24.6	25.6	26.9	28.3	29.8	31.6
	0.20	51.9	34.1	28.0	26.1	25.4	24.9	24.3	23.7	23.2	22.9	22.8	22.8	23.1	23.7	24.4	25.3	26.5	27.8	29.4	31.2	33.1
	0.25	51.9	33.3	27.9	26.7	26.3	25.8	25.1	24.4	23.8	23.3	23.2	23.3	23.6	24.2	25.0	26.1	27.3	28.9	30.6	32.6	34.7
	0.30	51.9	32.6	28.0	27.4	27.2	26.7	25.8	24.9	24.2	23.7	23.5	23.6	24.0	24.7	25.6	26.8	28.2	29.9	31.8	34.0	36.5
	0.35	51.9	32.0	28.3	28.3	28.2	27.4	26.3	25.3	24.5	23.9	23.8	23.9	24.4	25.2	26.2	27.5	29.1	31.0	33.2	35.6	38.3
	0.40	51.9	31.5	28.7	29.1	29.0	28.1	26.8	25.5	24.6	24.1	24.0	24.2	24.8	25.6	26.8	28.3	30.1	32.2	34.6	37.3	40.3
	0.45	51.9	31.2	29.2	30.0	29.8	28.6	27.0	25.7	24.8	24.3	24.2	24.5	25.2	26.1	27.5	29.1	31.1	33.4	36.1	39.1	42.4
	0.50	51.9	30.9	29.9	30.9	30.5	29.0	27.2	25.8	24.8	24.4	24.4	24.8	25.6	26.7	28.1	30.0	32.2	34.7	37.7	41.0	44.7
	0.55	51.9	30.7	30.6	31.8	31.1	29.2	27.3	25.8	24.9	24.5	24.6	25.1	26.0	27.2	28.9	30.9	33.3	36.2	39.4	43.1	47.2
	0.60	51.9	30.6	31.3	32.6	31.6	29.4	27.3	25.8	24.9	24.6	24.8	25.4	26.4	27.8	29.6	31.9	34.5	37.7	41.3	45.4	49.9
	0.65	51.9	30.6	32.1	33.3	31.9	29.5	27.3	25.8	25.0	24.8	25.0	25.7	26.9	28.4	30.4	32.9	35.9	39.3	43.3	47.8	52.7
	0.70	51.9	30.6	32.9	34.0	32.2	29.5	27.2	25.7	25.0	24.9	25.3	26.1	27.4	29.1	31.3	34.0	37.3	41.1	45.5	50.4	55.8
	0.75	51.9	30.7	33.6	34.6	32.3	29.4	27.1	25.7	25.1	25.1	25.5	26.5	27.9	29.8	32.2	35.2	38.8	43.0	47.8	53.2	59.2
	0.80	51.9	30.9	34.4	35.0	32.4	29.3	27.0	25.7	25.2	25.3	25.8	26.9	28.4	30.5	33.2	36.5	40.4	45.1	50.4	56.3	62.7
	0.85	51.9	31.1	35.2	35.4	32.4	29.1	26.9	25.7	25.3	25.5	26.1	27.3	29.0	31.3	34.2	37.9	42.2	47.3	53.1	59.6	66.6
	0.90	51.9	31.4	35.9	35.8	32.3	29.0	26.8	25.8	25.4	25.6	26.4	27.7	29.6	32.1	35.4	39.3	44.1	49.6	56.0	63.1	70.6
	0.95	51.9	31.7	36.6	36.0	32.2	28.8	26.8	25.8	25.6	25.9	26.7	28.1	30.2	33.0	36.6	40.9	46.1	52.2	59.2	66.9	75.0
	1.00	51.9	32.0	37.2	36.2	32.1	28.7	26.8	25.9	25.7	**26.1**	27.0	28.6	30.9	34.0	37.9	42.6	48.3	55.0	62.6	70.9	79.5

Calculation of the Forecast on Row 11 and 12

Once the optimum values of alpha and beta are established, they can be used to forecast the level and trend. Row 10 is the final year of actual values. The trend component established in row 10 will be used in the forecast years for 2014 seed and 2015 forecast (rows 11 and 12).

Using the data in row 10, the seed year forecast in row 11 for 2014 is developed using the ETS equations as follows:

$$Equation\ 1: L_t = 0.50 \times 96.01 + (1 - 0.50)(97.56 - 1.10) = 96.24$$

$$Equation\ 2: b_t = 0.0(96.24 - 97.56) + (1 - 0.0)(-1.10) = -1.10$$

$$Equation\ 3: F_{t+1} = 96.24 - 1.10 \times 1 = 95.14$$

The resulting value of 95.14 GJs is the 2014 seed year forecast value, shown on row 11, column 6 of the table above.

In row 12, “m” becomes 2 because we need to forecast two periods forward. L_t and b_t remain unchanged. For all subsequent forecast periods, the level is assumed to remain constant while the trend component changes linearly.

The forecast at any time (t+m) is calculated using equation 3 above. Thus, the forecast in row 12 for 2015 is calculated as follows:

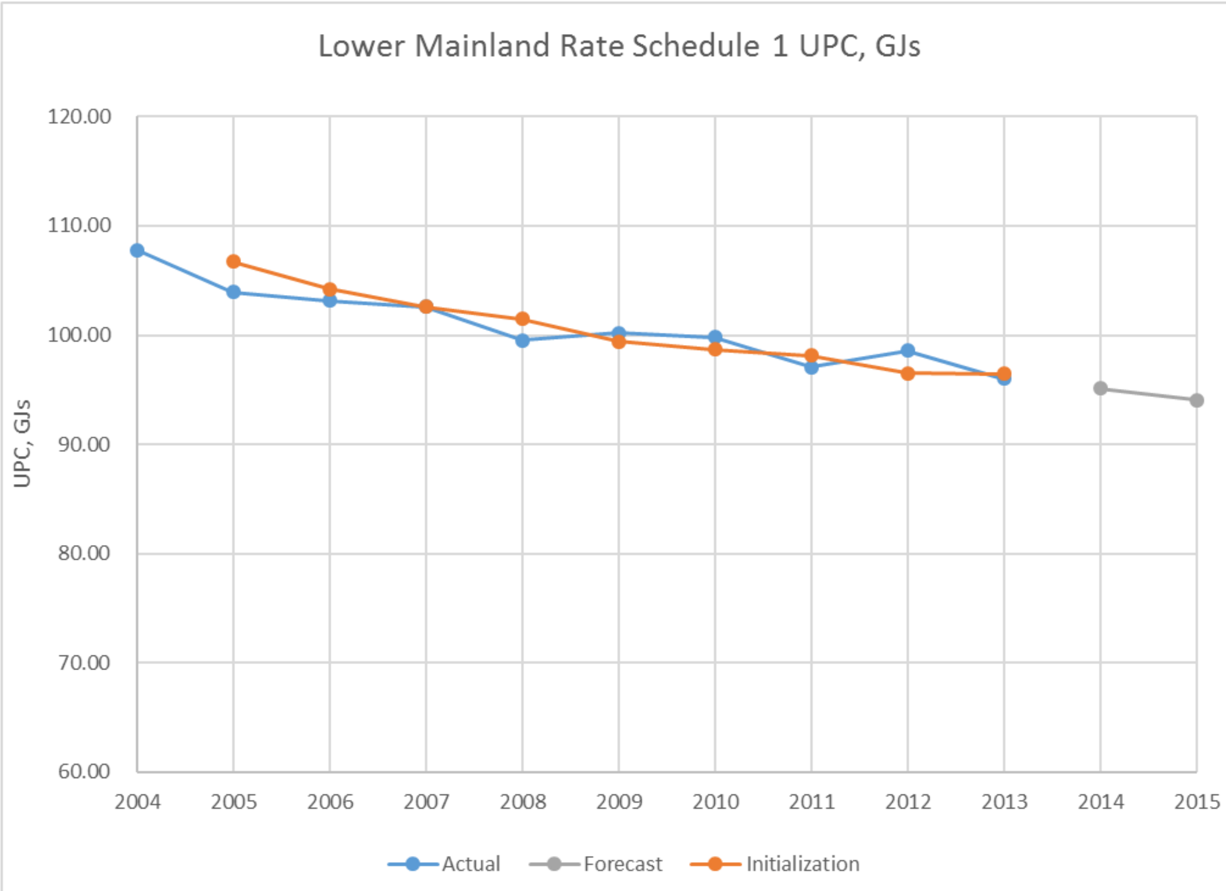
$$Equation\ 3: F_{t+1} = 96.24 - 1.10 \times 2 = 94.04$$

The resulting 94.04 GJs is the forecast value shown for 2015 on row 12, column 6.

Summary Plot

A plot of the actuals and forecast values demonstrates the reasonableness of the forecast:

Figure A3-10: Actuals and ETS Forecast Values



The above plot shows the initialization data (orange) developed with the optimized values of alpha and beta. If less optimal values are chosen, the orange line will deviate further from the actual line and result in a less accurate forecast.

Calculations for commercial use rates and customer additions are identical not reproduced here.

Appendix B

Natural Gas for Transportation and LNG Service

Table of Contents

1. INTRODUCTION

FEI continues to add natural gas demand to the distribution system through the increased adoption of natural gas as a transportation fuel. This increased adoption also results in FEI contracting with natural gas for transportation (NGT) customers for compressed natural gas (CNG) and liquefied natural gas (LNG) fueling services at both existing FEI fueling stations as well as constructing new fueling stations where required. In addition to fueling station services, FEI also supports the LNG customers with LNG logistics and fuel delivery services through the ownership and operation of LNG tanker assets. The LNG transportation and delivery service is offered as an optional service available to LNG customers under FEI's Rate Schedule 46 tariff.

FEI forecasts to continue to add natural gas demand to the distribution system by advancing both CNG and LNG applications across a variety of transportation market segments. To support and facilitate this natural gas demand, FEI is able to provide financial incentives to customers, which are enabled by the Greenhouse Gas Reduction (Clean Energy Act) Regulation (GGRR) for transportation and other allowable market segments. FEI also expects that the GGRR will enable an increased number of CNG and LNG fueling stations as the requirement for fueling infrastructure will continue to grow over the next number of years to support the growing number of natural gas vehicles.

This appendix provides details on FEI's 2019 revenue and cost forecasts for the NGT program, and transportation aspects of the LNG service. The NGT program consists of the construction and maintenance of the CNG or LNG fueling stations, the incentives to convert eligible vehicles from diesel and gasoline to natural gas and support for maintenance facility upgrades and training and support for customers adopting natural gas as a fuel.

The following table provides a brief summary of how each component of the NGT program relates to the 2019 forecast revenue requirement in this Application:

Table B-1: Connection between the NGT Program and the Revenue Requirement

Program Component	Connection to Revenue Requirement	Background
Vehicle[1] Conversion Incentives	Vehicle conversion incentives, and associated administrative costs, are included in a rate base deferral account and amortized through the delivery rates of non-bypass customers over a ten year period as approved by Order G-161-12.	The provision of incentives is a prescribed undertaking under section 2(1) of the Greenhouse Gas Reduction (Clean Energy Act) Regulation (GGRR).[2]

[1] Order in Council 609/2016 repealed the definition of "eligible vehicle" and replaced it with "eligible vehicle or machine". The term 'Vehicle' is used throughout this application to refer to both eligible vehicles or machines, and includes on-road trucks, buses, waste haulers, mine haul trucks, locomotives, marine vessels, asphalt pavers, fracture pump units, generators, boilers, burners and kilns.

[2] The setting of rates to recover the costs of prescribed undertakings is required under section 18 of the *Clean Energy Act*.

Program Component	Connection to Revenue Requirement	Background
Demand and Revenue Forecast	The demand associated with CNG & LNG NGT and non-NGT customers is embedded in Rate Schedules 3, 5, 23, 25, and 46, and as such, included in the overall utility revenue and delivery margin forecast for 2019 as set out in Section 3 of the Application.	The 2019 demand and revenue forecast for CNG and LNG is based on (i) existing demand and (ii) incremental demand for 2019 determined by utilizing the forecast vehicle conversion incentives and fueling station additions as the inputs, as well as the addition of non-NGT demand that FEI expects to serve under Rate Schedule 46.
Fueling Stations	Expenditures associated with fueling stations are included in the 2019 capital and O&M forecasts (Sections 6 of the Application for O&M forecasts and Section 7 of the Application for capital expenditure forecasts). The forecast capital and O&M of fueling station services included in the delivery cost of service is offset by the revenue recovered from participating fueling station customers. Forecast fueling station recoveries are included in Application Section 5 Other Revenue. In addition, an overhead and marketing charge approved by the Commission in Order G-78-13 is applied to FEI's fueling station customers. The forecast of this recovery is also included in Application Section 5 Other Revenue.	If a fueling station does not qualify as a prescribed undertaking for a CNG or LNG customer under the GGRR, FEI will apply for a CPCN for the construction and operation of that fueling station for a customer. For 2019, all of the fueling station additions are forecast to occur as prescribed undertakings under section 2(2) and 2(3) of the GGRR. The rate charged for each fueling station is approved separately by the Commission. That is, a service that qualifies as a prescribed undertaking under the Regulation requires an application to and approval of the rates by the Commission.
LNG Tanker Transportation Services	Operating costs associated with transportation service are forecast in O&M (Application Section 6). The capital costs for tankers are included in capital expenditures (Application Section 7). The forecast capital and O&M associated with the tankers included in the delivery cost of service is offset by the revenue from the Tanker Transportation Charge approved in Rate Schedule 46. Forecast recoveries of this charge are included in Section 5 of the Application - Other Revenue.	The expenditures for LNG tankers are a prescribed undertaking under section 2(3) of the GGRR.

The remainder of this appendix is organized as follows:

- <u>Section 2 - Background</u>: describes the regulatory history of FEI's NGT program, the regulation enabling the expansion of the NGT market, and the tariffs under which CNG and LNG supply is provided.

- Section 3 - Vehicle Incentives: provides a forecast of the incentives that will be provided in 2019.
- Section 4 - CNG & LNG Demand and Revenue: provides a forecast of natural gas demand for NGT and non-NGT demand and a discussion of the corresponding revenue and margin forecasts for 2019.
- Section 5 - NGT Fueling Station Services: provides a forecast of the costs and recoveries associated with fueling stations, including the number of stations, capital requirements for stations, and O&M forecasts for stations that will be constructed in 2019.
- Section 6 - Enabling LNG Demand Fulfilment: discusses the forecast costs and recoveries associated with the tanker transportation service provided under Rate Schedule 46.
- Section 7 - Conclusion: provides a summary of this appendix and a summary table showing the total O&M, capital and revenue forecast included in the 2019 forecast revenue requirement.

The organization of Sections 3 through 6 follows the progression of the business model for NGT. FEI provides incentives to customers for the purchase of CNG/LNG powered vehicles or the conversion of eligible vehicles (Section 3). These vehicles in turn create demand for both CNG and LNG (Section 4). To deliver the CNG/LNG, some customers require a fueling solution (Section 5). Finally, the demand for LNG necessitates that FEI produce LNG through the liquefaction of natural gas and, in some cases, transportation of LNG to the customer using FEI LNG tanker assets (Section 6).

2. BACKGROUND

2.1 NGT PROGRAM – GENERAL TERMS AND CONDITIONS (GT&C SECTION 12B)

On December 1, 2010, FEI filed an Application for Approval of General Terms and Conditions (GT&C) for Compression and Dispensing Service for CNG and Fuel Storage and Dispensing Service for LNG, (collectively CNG and LNG Service). The proposed Section 12B Vehicle Fueling Stations of FEI's GT&Cs (GT&C Section 12B) was designed to facilitate the development of both CNG and LNG refueling stations on the FEI distribution system that would be owned and operated by FEI. The Commission approved revised GT&C Section 12B by Order G-14-12 dated February 7, 2012.

2.2 NGT PROGRAM – GGRR

On May 14, 2012, the Government of British Columbia enacted the GGRR, which enables public utilities to:

1. Provide grants or zero-interest loans (and related expenditures) of up to $62.0 million in total for the purchase of eligible natural gas vehicles operating in British Columbia (Prescribed Undertaking 1);
2. Make expenditures of up to $12.0 million to own and operate CNG fueling stations and infrastructures (Prescribed Undertaking 2); and
3. Make expenditures of up to $30.5 million to own and operate LNG tankers and LNG fueling stations and infrastructure (Prescribed Undertaking 3).

The GGRR was initially set to expire on April 1, 2017. The rate treatment of these expenditures was approved for FEI in Commission Order G-161-12 on October 29, 2012. Order G-161-12 approved the NGT Incentives Account to capture costs related to Prescribed Undertaking 1: Vehicle Incentives or Zero Interest Loans. Order G-161-12 also approved the Fueling Stations Variance Account to capture costs related to Prescribed Undertaking 2: CNG Stations and Prescribed Undertaking 3: LNG Stations.[3] Order G-161-12 also approved the recovery of the balances in these accounts from all non-bypass natural gas customers.

On April 11, 2013, the Commission issued Order G-56-13 which addressed non-grant related issues with respect to the GGRR. On the same date the Commission also issued its Reasons for Decision for Order G-161-12 and Order G-56-13, which provided directives with respect to Prescribed Undertakings 1, 2 and 3.

[3] Subsequently, FEI requested to discontinue this deferral account effective January 1, 2017 and received approval to do so by the Commission in Order G-138-14.

FEI subsequently received approval in Order G-67-13 (dated April 30, 2013) for the rate treatment of incentives of $5.573 million incurred in 2010-2011.[4] The Commission determined that FEI was to include these expenditures as part of the $62.0 million funding limit established for Prescribed Undertaking 1 under the GGRR. As a result, FEI would be able to spend up to $56.427 million in additional funding under Prescribed Undertaking 1.

On November 27, 2013, the GGRR was amended to expand the list of vehicles eligible for financial incentives under Prescribed Undertaking 1 to include vehicles such as locomotives and mine haul trucks. Additionally, the expiration date of the GGRR was repealed and the definition of “expenditures” for the purposes of the GGRR was expanded to include binding commitments to incur expenditures in the future.

The GGRR was further amended on June 3, 2015. The 2015 amendments broadened the application of natural gas to more transportation sectors within the previously-established funding limits to promote continued development of the use of natural gas in certain transportation sectors. Important amendments included:

- extending the undertaking period to March 31, 2018;
- allowing a public utility to increase incentives by a defined amount for vehicles defined as an “early adopter vehicle”[5];
- providing an alternative for fueling station service agreements; and
- adding a prescribed undertaking that provides incentives for the conversion of a “specified vehicle”[6] to operate on natural gas and establishing an incentive cap for this incentive at $5 million (Prescribed Undertaking 3.1), to be recorded in the NGT Incentives Account, approved by Order G-161-12.

On August 19, 2016, the GGRR was further amended through Order in Council (OIC) No. 609[7]. The key 2016 amendments included:

- extending the undertaking period to March 31, 2022;
- broadening the definition of “eligible vehicle” to include “eligible vehicle or machine”;

[4] Pursuant to the directives in Order G-67-13, FEI transferred the $5.573 million for the 2010-2011 Incentives from the NGV Incentives deferral account approved by Order G-44-12 to the NGT Incentives Account approved by Order G-161-12. The NGV Incentives deferral account was closed subsequent to the transfer.

[5] “Early adopter vehicle” as defined in the GGRR, Section 2 Prescribed Undertakings.

[6] A “specified vehicle” means a heavy-duty vehicle, medium-duty vehicle, school bus or transit bus, as defined in the GGRR, Section 1.

[7] OIC No. 609 issued and deposited by the Lieutenant Governor in Council (LGIC) on August 19, 2016, under B.C. Reg. 201/2016.

- clarifying the cost of service recovery rules of CNG and LNG fueling stations by striking out “energy provided at each station…” and substituting “the station’s forecast total operating costs…”;
- increasing the allowable funds available under Prescribed Undertaking 1 from $62.0 million to $107.9 million;
    a. includes increasing the allowable expenditure on marketing, training, education and administration by $5.0 million from $3.1 million to $8.1 million; and
    b. increasing the amount of incentives available for eligible vehicles or machines under Prescribed Undertaking 1 by an incremental $40.9 million;
- creating a new Prescribed Undertaking to issue incentives of up to $6.1 million for remote industrial power generation applications such as generators, boilers, kilns, burners that use natural gas as a fuel source;
- clarifying that incentives issued under Prescribed Undertaking 1 to a “Shipping, passenger transportation or commercial services by marine vehicle that will use fuel purchased from a public utility” may be made to persons who are not in British Columbia but will be required to procure fuel from the utility; and
- creating a new Prescribed Undertaking for allowable investment in infrastructure pertaining to LNG distribution and storage infrastructure to not exceed $15 million during the undertaking period.

On March 21, 2017, the GGRR was further amended through OIC No. 161[8]. The key 2017 amendments included:

- increasing the allowable incentives available under Prescribed Undertaking 1 from $107.9 million to $177.9 million for eligible vehicles or machines;
- adding a new subsection specifying that expenditures may exceed $177.9 million by a further $40 million if the $40 million is for expenditures in relation to eligible vehicles or machines operated on liquefied natural gas or compressed natural gas all of which is derived from biogas or biomass;
- increasing the allowable infrastructure investment under Prescribed Undertaking 3 by $20 million from $30.5 million to $50.5 million;
- creating a new prescribed undertaking for allowable infrastructure investments in LNG shore-side assets to not exceed $25 million over the undertaking period; and

[8] OIC No. 161 issued and deposited by the LGIC on March 22, 2017, under B.C. Reg 114/2017.

- adding subsection 3.6 to allow a public utility, during the undertaking period, to make expenditures on feasibility and development costs in relation to shore-side assets that do not exceed $5 million.

On April 20, 2018, the GGRR was further amended by OIC No. 199[9]. The following is a summary of the specific amendments in OIC No. 199:

- Increasing the *average* expenditure on CNG fueling stations from $2 million per station to $3 million per station; and
- Grouping together the maximum allowable expenditures on CNG and LNG fueling infrastructure to a maximum of $62.5 million.

For all CNG and LNG fueling stations, the rates related to each new fueling station service agreement provided under the GGRR will be submitted in separate applications to the Commission for review and approval.

2.3 LNG AND CNG SUPPLY

FEI is supplying LNG to both NGT and non-NGT customers under the Rate Schedule 46 tariff on a firm (short and long term contract) and spot basis.

For CNG services, FEI has four Commission-approved CNG natural gas vehicle Tariffs: Rate Schedule 6 Natural Gas Vehicle Service, Rate Schedule 6A General Service Vehicle Refueling Service, Rate Schedule 6P Public Service and Rate Schedule 26 Natural Gas Vehicle Transportation Service.

In addition to the above Rate Schedules, FEI also provides natural gas distribution service using existing Rate Schedules 3, 5, 23 and 25.

2.3.1 CNG and LNG Fueling Station Service

The rates for fueling station services that FEI provides to CNG and LNG customers are not contained in the Rate Schedules referenced above, which are only for the distribution and delivery of the natural gas to the customer's location. Rates for fueling station services are agreed upon individually between FEI and the NGT customers and these rates are filed for approval on an agreement-by-agreement basis with the Commission.

[9] OIC No. 199 issued and deposited by the LGIC on April 20, 2018, under B.C. Reg 84/2018.

3. VEHICLE INCENTIVES

As discussed in Section 2.2 above, the GGRR 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 a potential $40 million additional for those NGT customers that take either LNG or CNG wholly derived from biomass or biogas, plus an additional $6.1 million in grants or zero-interest loans for the purchase of generators, boilers, burners or kilns that use natural gas to produce electricity.

Applications for incentive funding are accepted every quarter and an independently appointed fairness advisor ensures that the evaluation process and the provision of funds are conducted in an objective, consistent and fair manner. The fairness advisor is an independent consultant that reviews and provides comments on the GGRR program and the processes to ensure that all decisions made by FEI are made objectively, with a focus on openness, competitiveness, transparency and compliance.

Table B-2 below provides a summary of GGRR incentives under Prescribed Undertaking 1 and Prescribed Undertaking 3.2 projected to be issued in 2018 and forecast to be issued in 2019 by category. The table below reflects the forecast incentives that will be issued and added to the NGT 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.

Table B-2: FEI Forecast GGRR (NGT) Incentive Deferral Additions ($millions)[10]

Incentive Forecast ($ millions)	2018A	2018P	2019F
Total Vehicle Incentives	$ 3.375	$ 2.850	$ 3.500
Marine, Mining & Rail Incentives	$ 6.000	$ 4.625	$ 6.625
Remote Power	$ 1.200	$ -	$ -
Safety Practices and Maintenance Facilities Incentives	$ 0.700	$ 0.700	$ 0.700
Admin, Education, Safety Training	$ 1.000	$ 1.000	$ 1.000
Total	$ 12.275	$ 9.175	$ 11.825

Typically there can be a lag of up to two years (or more for marine customers) between the time an applicant applies for incentive funding and when the vehicles (or marine vessels) are in service and operational. For this reason FEI has a two-step process for issuing incentives. A smaller amount (up to 25%) is paid to the customer at the time of approving the application for incentives and the remaining amount is paid to the customer once the vehicles/marine vessels are in service and fully operational.

[10] Throughout the tables in this appendix, "A" refers to Approved for 2018, "P" refers to Projected for 2018, and "F" refers to Forecast for 2019.

For the 2018 Projection, FEI anticipates issuing a total of $9.175 million in incentives. This includes incentives of:

- $7.475 million for vehicle, marine and mining incentives;
- $1.000 million related to administration, education and safety training; and
- $0.700 million related to safety practices and maintenance facility upgrades.

Of the total amount of $7.475 million in vehicle incentives, $2.850 million is allocated for fleet conversion incentives (i.e. excluding marine, mining and rail related incentives). Of the $2.850 million for fleet conversion incentives, $2.750 million consists of incentives for CNG vehicles and $0.100 million for incentives for LNG vehicles that have entered service in 2018 and incentives for a portion of the CNG vehicles expected to be in service in early 2019.

Of the total amount of $7.475 million in vehicle incentives, $4.625 million of incentives is allocated for marine, mining and rail applications. Of the $4.625 million of incentives, $3.375 million is allocated for 75 percent of the agreed incentive contribution for BC Ferries' two vessels: the Salish Raven and the Spirit of BC. The remaining $1.250 million is allocated to the 25% initial payment of the $5.000 million incentive to Seaspan's two vessels.

For the 2019 Forecast, FEI forecasts total expenditures of $11.825 million for eligible vehicles and remote power projects, implementation of safety practices and improvement of facilities for operating vehicles, and expenditures for administration, education and training. This includes expenditures of:

- $6.625 million incentives for the marine, mining and rail category;
- $3.500 million for CNG and LNG vehicle incentives; and
- $1.700 million for administration, education, safety training and safety practices.

4. CNG & LNG DEMAND AND REVENUE

4.1 FORECAST NGT & NON-NGT DEMAND

Table B-3 below provides a projection and forecast of total NGT and non-NGT demand in 2018 and 2019, respectively, based on the expected number of vehicles that will be added, in addition to existing vehicles that are in operation. Non-NGT volumes are mainly related to LNG demand from power generation and non-transportation customers. As directed in Order G-86-15, FEI has included a 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 B-3: FEI Total Natural Gas Demand for NGT & Non-NGT (GJ per year)

GJ	2018A	2018P	2019F
CNG	920,525	906,972	1,074,309
LNG	901,250	1,169,154	1,526,049
Total NGT Demand	**1,821,775**	**2,076,126**	**2,600,358**
Non-NGT Demand	210,000	170,460	170,460
Total NGT and Non-NGT Demand	**2,031,775**	**2,246,586**	**2,770,818**

The total forecasted natural gas demand for CNG and LNG applications for 2019 of 2,770,818 GJ includes forecasted spot volumes of 170,460 GJ. The spot volumes are related to non-NGT customers, mostly for power generation[11]. These power generation customers typically have a consistent load profile from year to year and therefore the power generation demand forecast (under non-NGT) was based on the 2017 actual and 2018 projected volumes.

The incremental increase in total demand between 2018 and 2019 is 524,232 GJ. The following table summarizes the demand that makes up this incremental load.

Table B-4: 2019 Forecast Incremental Demand Additions by CNG and LNG

	2019 Incremental Demand (GJ)
CNG	167,337
LNG	356,895
Total Incremental NGT Demand	**524,232**
Non-NGT CNG/LNG Incremental Demand	-

[11] Spot Volumes for Cryopeak, NWT Energy Corp, Yukon Energy and Anahim Lake are non-NGT and are mainly for power generation.

The incremental NGT and non-NGT demand of 524,232 GJ represents an annual growth rate of about 23 percent over the projected 2018 natural gas volumes. This increase is mainly attributed to realizing full year demand from the first BC Ferries Spirit Class LNG vessel, mid-2019 in-service date of the second BC Ferries Spirit Class LNG vessel, and TransLink's CNG bus fleet expansion.

4.2 FORECAST REVENUE, COST OF GAS AND DELIVERY MARGIN

Currently, FEI delivers CNG and LNG to all fueling stations under Rate Schedules 3, 5, 23, 25 and 46 (LNG only). FEI has used the forecast volumes from section 4.1 above to calculate the associated revenue, cost of gas and delivery margin at existing rates. The volumes presented in this appendix are for all CNG and LNG volumes from customers served under Rate Schedules 3, 5, 23, 25 and 46. The LNG volume dispensed under Rate Schedule 46 also includes volumes provided to non-NGT customers.

The following two tables identify, for the rate schedules, the forecast of CNG and LNG volumes sold, associated delivery margin at 2018 rates[12], cost of gas, and revenue (delivery margin plus cost of gas). All forecasts are included in the financial schedules within this Application.

Table B-5: Rate Schedule 3, 23, 5, and 25 CNG Projection and Forecast

CNG - Volume, Revenue, Margin under RS 3, 5, 23, and 25	2018A	2018P	2019F
Demand (GJ)	920,525	906,972	1,074,309
Total Delivery Margin ($ millions)	$ 1.718	$ 1.692	$ 1.927
Total Cost of Gas ($ millions)	$ 0.600	$ 0.497	$ 0.580
Total Revenue ($ millions)	$ 2.319	$ 2.189	$ 2.507

Table B-6: Rate Schedule 46 LNG Projection and Forecast[13]

LNG - Volume, Revenue, Margin under RS 46	2018A	2018P	2019F
Demand (GJ)	1,111,250	1,339,614	1,696,509
Total Delivery Margin ($ millions)	$ 5.368	$ 6.508	$ 8.401
Total Cost of Gas ($ millions)	$ 3.805	$ 3.851	$ 5.088
Total Revenue ($ millions)	$ 9.173	$ 10.360	$ 13.489

[12] For this purpose, delivery rates exclude the delivery rate riders which are calculated separately.

[13] A break out of the total Rate Schedule 46 demand into NGT and non-NGT categories is provided in Section 4.1 of this Appendix and also shown in Figure 3-12 of the Application. The variance between 2018A and 2018P LNG demand is mainly due to the timing of the BC Ferries Spirit Class vessel, and TransLink's fleet expansion as discussed in Section 3.5.4 of the Application.

5. NGT FUELING STATION SERVICES

FEI provides fueling station infrastructure under the two approved regulatory models, the FEI GT&C Section 12B Vehicle Fueling Stations and the GGRR.

The Commission-approved GT&C Section 12B applicable fueling station agreements sets out the terms for FEI's ownership and operation of fueling stations. For CNG assets, GT&C Section 12B applies to "installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer/dehydrator, high pressure storage, dispensing equipment; and dispensing of compressed natural gas". For LNG assets, GT&C Section 12B applies to "installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and dispensing of liquefied natural gas."

The second model under which FEI can provide fueling infrastructure is under the provisions of the GGRR. As mentioned above, the GGRR enables public utilities to make expenditures of up to $62.500 million to own and operate CNG and LNG fueling stations and infrastructure[14].

The following subsections discuss the existing approved fueling stations, forecast fueling station additions (including the forecast capital and operating costs embedded in the 2019 forecast revenue requirement) and the forecast recoveries related to fueling stations, which serve to offset the costs.

5.1 *APPROVED FUELING STATIONS*

To date, FEI has completed the construction of ten CNG fueling stations with United Parcel Services (UPS) being the most recently completed station.

The table below summarizes all CNG fueling stations constructed or under construction, as well as the applicable regulatory model under which the construction of each station was undertaken. The Waste Management of Canada Corporation (Waste Management) agreement was developed based on previously proposed GT&Cs, and was accepted by the Commission "on an exception basis only"[15].

[14] $62.5 million total investment per utility over the regulation period, which ends March 31, 2022, which was amended by OIC 199 in April 2018.
[15] Commission Order G-128-11; Appendix A, dated July 19, 2011, p. 31.

Table B-7: CNG Fueling Stations Constructed by FEI

Customer/Station	Applicable Order Number	Regulatory Model
Progressive Waste Solutions	C-6-12/G-78-13	GT&C Section 12B
Waste Management	G-128-11/G-229-13	GT&C Section 12B
Kelowna School District	G-158-13	GT&C Section 12B
Cold Star	G-187-13	GGRR
Smithrite	G-72-14	GGRR
For Less Disposal	G-128-14	GGRR
City of Vancouver	G-105-15	GGRR
Burnaby Operations (Canadian Linen and Disposal Queen)	G-91-16/G-96-16	GGRR
Mid Island (City of Nanaimo and Nanaimo Cold)	G-99-16/G-100-16/G-101-16	GGRR
United Parcel Service	G-195-17	GGRR

FEI has constructed six LNG fueling stations to date. The table below summarizes the approvals granted for each of these stations. All of the LNG fueling stations, with the exception of the station on the premises of Vedder Transport Ltd. in Abbotsford, were constructed under the provision of the GGRR.

Table B-8: LNG Fueling Stations Constructed by FEI

Customer/Station	Applicable Order Number	Regulatory Model
Vedder	G-22-14	GT&C Section 12B
Arrow Transport	G-33-14	GGRR
Denwill	G-34-14	GGRR
Westcan Bulk Transport	G-35-14	GGRR
Teck Coal Ltd.	G-151-15	GGRR
Cool Creek (Vedder Resources)	G-83-16	GGRR

5.2 *FORECAST FUELING STATIONS AND CAPITAL EXPENDITURES*

FEI is not projecting to construct any LNG fueling stations for the remainder of 2018. For 2019, FEI is forecasting one additional LNG station that would support a potential customer deploying LNG trucks in BC.

In 2018, FEI originally expected to construct 2 CNG stations. This has been revised lower and FEI projects the addition of one CNG station in 2018 and forecasts two additional CNG fueling stations constructed in 2019. The reduction from two to one CNG station in 2018 was a result of a customer delaying their CNG adoption plans to 2019. The following table provides the total projected and forecast number of FEI-owned stations as at December 31 for 2018 and 2019, respectively.

Table B-9: Forecast Total FEI Fueling Stations

	2018A	2018P	2019F
CNG Stations	12	11	13
LNG Stations	6	6	7
Total	18	17	20

The following table provides a summary of total capital expenditures projected in 2018 and forecast for 2019 related to the fueling station additions.

Table B-10: NGT Fueling Station Capital Expenditures & Additions Forecast

$ millions	2018A	2018P	2019F
CNG Stations	$ 6.000	$ 2.670	$ 5.000
LNG Stations	-	-	1.105
Total	**$ 6.000**	**$ 2.670**	**$ 6.105**

For 2018, the total capital expenditure projected for CNG stations is approximately $2.670 million and no capital expenditure projection for LNG stations. Of the $2.670 million of capital for CNG fueling stations projected for 2018, $2.500 million is estimated for the addition of a new CNG station and the remaining $0.170 million is allocated for a station expansion at one of FEI's existing CNG fueling stations.

For 2019, the $6.105 million capital expenditure forecasted is the total of the two new CNG fueling stations estimated at $2.500 million each and a LNG fueling station at $1.105 million.

Capital expenditures may differ from capital additions due to the lag between when capital dollars are spent and when the assets are placed into service. However, for the forecast fueling station additions for 2018 and 2019, the expenditures are assumed to occur the same year that the assets are placed into service. The 2019 capital additions for the CNG and LNG stations are embedded in the total found in Section 11, Schedule 4, Line 31, Column 4, under the NGT Assets heading.

5.3 *FORECAST FUELING STATION OPERATIONS AND MAINTENANCE (O&M)*

Forecast O&M expenses related to the operation of the CNG and LNG fueling stations are recovered directly from participating customer(s) of each fueling station through the rates charged to those customers. This is described in more detail in Section 5.4 below.

Table B-11 below shows the forecast O&M expenses for FEI's existing fueling stations the additional CNG fueling station in 2018, and the additional three fueling stations that will be constructed in 2019.

Table B-11: Forecast Annual CNG and LNG Fueling Station O&M[16]

$ millions	2018A	2018P	2019F
CNG Stations	$ 0.988	$ 0.700	$ 0.929
LNG Stations	$ 0.417	$ 0.478	$ 0.540
Total	**$ 1.405**	**$ 1.177**	**$ 1.469**

[16] Excludes the O&M forecast of $0.870 million in 2019 for the LNG Tanker Service as discussed in Section 6.1 of this Application.

The O&M increase for CNG stations from 2018 Projected $0.700 million to 2019 Forecast $0.929 million is mainly due to the addition of two CNG stations forecasted to be constructed in 2019. The O&M increase for LNG stations from 2018 Projected $0.478 million to 2019 Forecast of $0.540 million is due to the addition of one LNG station forecasted to be constructed in 2019.

5.4 *FORECAST FUELING STATION RECOVERIES*

The 2019 forecast also includes CNG and LNG service revenues and NGT overhead and marketing recoveries within Other Revenue that offset the forecast cost of service of the fueling station services. These two revenue items are described further below.

5.4.1 CNG and LNG Service Revenue Forecast

FEI forecasts the fueling station recoveries for 2019 to be $3.373 million, an increase from the 2018 projected recoveries of $3.055 million. The forecast is based on the approved rates of the 16 completed fueling stations already in-service as identified in Tables B-7 and B-8, and the two new CNG and one new LNG fueling station forecasted to be constructed in 2019 as discussed in Section 5.2 of this Appendix.

Table B-12 provides a breakdown between CNG and LNG station recoveries. Any variance in forecast CNG and LNG service revenue will be captured in the CNG and LNG Recoveries deferral account.

Table B-12: CNG and LNG Fueling Service Station Revenue Forecast ($millions) [17]

CNG/LNG Service Revenue		2018A		2018P		2019F
CNG Station	$	1.870	$	1.547	$	1.836
LNG Station	$	1.364	$	1.422	$	1.450
Subtotal - NGT Stations	**$**	**3.234**	**$**	**2.969**	**$**	**3.286**
Surrey Ops CNG Pump	$	0.034	$	0.086	$	0.086
Total	**$**	**3.268**	**$**	**3.055**	**$**	**3.373**

5.4.2 NGT Overhead and Marketing Recoveries Forecast

Pursuant to Order G-78-13, FEI has forecast for 2019 a recovery of overhead and marketing (OH&M) from FEI's NGT fueling station customers. Table B-13 below also provides a projection of recoveries of OH&M from NGT customers.

As shown in Table B-13 below, the total projection of NGT OH&M revenue for 2018 is $0.312 million and the forecast NGT OH&M revenue for 2019 is $0.325 million. This revenue is

[17] Where a Commission approved CNG agreement or LNG agreement outlines terms and conditions for use by other customers, more than one CNG or LNG customer may receive CNG or LNG fueling service at an NGT Fueling Station (as outlined in Tables B-8 and/or B-9), where applicable.

calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[18] 2018 projected and 2019 forecast CNG and LNG sales volumes, respectively.

Table B-13: NGT Overhead and Marketing Revenue Forecast

NGT Overhead and Marketing Revenue	2018A	2018P	2019F
Applicable Volume (GJ)	616,278	599,317	624,316
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.320**	**$ 0.312**	**$ 0.325**

5.5 *SHORT TERM LNG FUELING SERVICES*

On June 21, 2016, FEI applied for approval from the Commission to transfer specific LNG assets comprised of the IMC 6000 and two Orca LNG units (the Specific LNG Assets), which were held outside of FEI's rate base at that time, to the general natural gas rate base, and to approve a rate to provide short-term LNG fueling service using these specifc LNG assets. These specified LNG assets are essentially mobile LNG refueling stations. The Commission approved the transfer of these assets to the general natural gas rate base, and approved a short-term fueling service rate on a permanent basis on March 23, 2017 by Order G-44-17.

5.5.1 Forecast Short Term LNG Fueling Recoveries

Order G-44-17 approved a rate of $10,500 per month per unit to be applied to LNG customers that use these assets for short term fueling services. The table below provides a summary of the 2018 Projected and 2019 Forecast amounts pertaining to the use of these short term fueling assets.

Table B-14: Short Term LNG Fueling Revenue Projection and Forecast

LNG Short Term Fueling	2018A	2018P	2019F
No. of Specific LNG Assets Used	2	-	-
No. of Months Under Use	6	-	-
Rate ($/month/unit)	10,500	10,500	10,500
Total ($ millions)	$ 0.126	$ -	$ -

These assets are considered fueling assets and as such the revenue collected from the use of these assets is recorded under Other Revenue as "CNG & LNG Service Revenues" and is shown in Section 11 Financial Schedules 23.

5.5.2 Forecast Short Term LNG Fueling Capital Expenditures

FEI is not projecting any capital expenditures for the Short Term LNG Fueling Service in 2018 and in 2019.

[18] This volume is limited to CNG and LNG contract volume delivered through an FEI-owned CNG or LNG fueling stations for the host customer and for all volumes related to third parties fueling at host stations.

5.5.3 Forecast Short Term LNG Fueling Operations and Maintenance (O&M)

The forecast O&M expenses for the operation of the specific LNG assets under the Short Term LNG fueling service are embedded and recovered from the approved rate ($10,500 per month per unit) as discussed in Section 5.5.1 of this Appendix.

Based on the estimated use in 2018 and 2019, the 2018 Projected and 2019 forecast O&M expenses for the Short Term LNG Fueling Service is estimated to be $0.000 million for both years.

6. ENABLING LNG DEMAND FULFILMENT

FEI provides an optional transportation service to LNG customers for the hauling of the LNG between LNG facilities and the customer's designated location. This optional service is interrelated with the NGT program and is part of Rate Schedule 46 (the LNG Transportation Service). Furthermore, the LNG tanker expenditures are a prescribed undertaking under the GGRR[19], for which cost recovery is provided in section 18 of the Clean Energy Act.

6.1 *LNG TRANSPORTATION SERVICE UNDER RATE SCHEDULE 46*

6.1.1 LNG Tanker Capital Expenditure Forecast

FEI is projecting approximately $1.7 million in capital expenditures in 2018 and forecasting $2.350 million in 2019. For 2018, this includes the payment for the remaining balance for the two marine tankers ordered in 2017, upgrades to logistical and management systems, remote monitoring equipment and a nitrogen generator with trailer.

For 2019, the capital additions include one new marine tridem tanker, six standard tandem tankers or ISO containers and the associated remote monitoring equipment, to serve the growing LNG demand. These trailer purchases will be made in 2019 in order to support additional growth forecast projected for 2020 and beyond. The costs of the tankers are offset by the approved Rate Schedule 46 LNG applicable tanker charge.

6.1.2 Tanker O&M Forecast

FEI is forecasting the 2019 O&M expenses for LNG tankers to be $0.870 million, which is comprised of $0.770 million for LNG tanker trailers and $0.100 million for Emergency Response and Preparedness (ERAP) coverage. The increase in O&M in 2019 is attritubted to increased in costs for servicing and maintaining a growing LNG trailer fleet, logistics and GPS and outsourcing purging of trailers which used to be done internally by the LNG plant. LNG is sold under Rate Schedule 46 as free-on-board (FOB) at the LNG facility. As such, under Transport Canada Regulations, as the producer of a dangerous good as defined by Transport Canada, FEI is required to provide a registered ERAP plan for the LNG product while in transit. The plan lays out the process, checklist and roles and responsibilities of those resources that would be involved in responding to an LNG emergency. Resources include LNG plant personnel that provide the role of technical advisors, and incident responders with support from Quantum Murray, an emergency response contractor that has been trained in LNG.

[19] Prescribed Undertaking 2.

6.1.3 Tanker Rental Revenue Forecast

Tanker rental revenues are the revenues FEI collects from customers when FEI uses an FEI-owned tanker to deliver LNG to a customer.

FEI has forecast its 2019 tanker rental revenues as shown in Table B-15 below based on the 2018 projected tanker deliveries plus additional deliveries to account for incremental 2019 forecast LNG volumes. As described in Section 6.1.1 of this appendix, FEI is acquiring one new marine equipped tridem tanker for 2019 to service the growing marine load. The table below summarizes the expected revenue per the currently approved Rate Schedule 46 tanker rental rates.

Table B-15: LNG Tanker Rental Revenue

Tanker Rental Revenue		2018A		2018P		2019F
Standard Tanker Rental Deliveries		840		624		627
Rate ($/Delivery)	$	274	$	274	$	279
Sub Total ($ millions)	$	0.230	$	0.171	$	0.175
Tridem Tanker Rental Deliveries		130		113		112
Rate ($/Delivery)	$	329	$	329	$	335
Sub Total ($ millions)	$	0.043	$	0.037	$	0.038
Marine Equipped Tridem Tanker Rental Deliveries		670		651		990
Rate ($/Delivery)	$	463	$	463	$	472
Sub Total ($ millions)	$	0.310	$	0.301	$	0.467
Total Tanker Rental Revenue ($millions)	**$**	**0.583**	**$**	**0.510**	**$**	**0.680**

7. CONCLUSION

The following table provides a summary of the total O&M, capital and revenue forecast included in the 2019 forecast revenue requirement.

Table B-16: Summary of 2019 Forecast Revenues and Costs ($ millions)

Particular	2019	Reference
Incentives (deferral additions)	$ 11.825	Section 11, Schedule 11, Line 19, Column 4
Capital Expenditures		
Fueling Stations	6.105	Section 11, Schedule 4, Line 33, Column 4
Tankers	2.350	Section 11, Schedule 4, Line 33, Column 4
Total Capital Expenditures	$ 8.455	
Revenue		
Delivery Margin	$ 10.327	Appendix B, Table B-5 and B-6
Fueling Station	3.373	Section 11, Schedule 23, Line 10, Column 3
Overhead & Marketing	0.325	Section 11, Schedule 23, Line 7, Column 3
Tanker Rental	0.680	Section 11, Schedule 23, Line 6, Column 3
Total Revenue	$ 14.705	
O&M		
Fueling Stations	$ 1.469	Appendix B, Table B-11 & Appendix B, Section 5.5.3
Tankers	0.770	Appendix B, Section 6.1.2
ERAP	0.100	Appendix B, Section 6.1.2
Total O&M	$ 2.339	

Appendix C

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-138-14 – FEI MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
1.	82	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	Consultation with stakeholders on the study's terms of reference and the choice of consultant has been completed. The study is currently in progress and will be filed later in 2018, after a workshop (to be scheduled) with stakeholders to review the results of the study.	N/A
2.	217	99	***Accounting Changes:*** The Panel directs FEI to communicate any accounting policy changes/updates to the Commission and other stakeholders as part of its Annual Review process during the PBR period.	Ongoing during PBR period.	Section 12.3
G-86-15 – FEI ANNUAL REVIEW FOR 2015 DELIVERY RATES					
3.	13	11	***Spot Purchases*** In future annual reviews, FEI is directed to address the issue of spot purchases more fully and provide a proposal for including some or all of these purchases in the demand forecast based on an analysis of the probability of various outcomes.	Ongoing during PBR period	Appendix B Section 4.1
4.	19	14	***Safety Service Quality Indicators*** 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. The Panel also agrees that with regard to the SQI Public Contact with Pipelines, the number of line damages and the number of calls to BC One Call would be helpful and directs FEI to also provide this information in future annual reviews.	Ongoing during PBR period	Section 13.2.1 (Public Contact with Pipelines) and 13.2.3 (Leaks per KM of Distribution System Mains)
5.	19	15	***Historical Service Quality Indicators*** FEI is directed to provide SQI results from 2009 onward for future annual reviews.	Ongoing during PBR period	Section 13.2.1, 13.2.2 and 13.2.3

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
6.	19	16	***Transmission Reportable Incidents Service Quality Indicator*** For subsequent annual reviews, FEI is directed to report the number of Transmission Reportable Incidents in each of the severity levels.	Ongoing during PBR period	Section 13.2.3
7.	19	17	***GHG Emissions*** With regard to including the Estimated Annual GHG Emissions (in tCO2e) reported by the Company to the Ministry of Environment, the Panel has no objection, and directs FEI to provide this information in future annual reviews.	Ongoing during PBR period	Section 13.3
8.	34	28	***Reporting on Initiatives during PBR Term*** The Panel directs FEI to continue to provide in each annual review application the information that was provided in response to BCUC IRs 1.2.9 (Regionalization Initiative) and 1.3.3 (Project Blue Pencil) and to update these tables for actual results as this data becomes available. The same analysis is to be performed on new initiatives that are implemented during the PBR term.	Ongoing during PBR period	Appendix C2
9.	35	30	***Number of Employees*** The Panel directs FEI to include in its annual review filings both the total year-end number of employees and the total year-end number of Full Time Equivalent Employees.	Ongoing during PBR period	Table 1-3 in Section 1.4.2
G-120-15 – FEI-FBC PBR CAPITAL EXCLUSION CRITERIA					
10.	17	4	***Capital Expenditures Exceeding the Deadband*** Should the dead-band for annual capital expenditures approved in the PBR Plans be exceeded FBC or FEI are directed to include in its next Annual Review filing, recommendations as to any adjustment to base capital (re-basing) for Commission approval.	Completed	Section 1.4.4
G-193-15 – FEI ANNUAL REVIEW FOR 2016 RATES					
11.	8	6a	***2017 LTRP Application Deferral Account*** FEI estimates the cost of third party consultants to assist with preparatory work for the 2017 LTRP Application to be $1.050 million (over two years). The Panel considers this amount to be a ceiling and directs FEI to submit any amount in excess of this to the Commission for approval prior to committing to expenditures	N/A – FEI confirms not over the ceiling.	Section 7.5.2.1
12.	22	n/a	***Presentation of Historical SQI Results*** The Panel acknowledges FEI's statement that it will present the test year and historical SQI results in a single table in future annual review filings, as requested by BCSEA.	Ongoing during PBR period.	Sections 13.21, 13.2.2 and 13.2.3

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
13.	24	12a	***Costs Allocated to FBC for Call Handling*** If in the future the annual costs being allocated to FBC from FEI for the handling of calls exceeds $100,000 in any one year, FEI is directed to provide an analysis of various cost allocation methodologies and provide evidence as to which will provide the most appropriate results.	Confirmed costs do not exceed $100,000.	N/A
14.	25	n/a	***Revenue Deficiency Reconciliation*** The Panel is satisfied with FEI's reconciliation provided as Table 1 in its reply submission and notes FEI's agreement to provide a reconciliation between the contributors to the revenue deficiency and the financial schedules in its future annual review applications.	Ongoing during PBR period.	Section 1.5 revenue deficiency summary agrees to Schedule 1 of Section 11
G-182-16 – FEI ANNUAL REVIEW FOR 2017 RATES					
15.	9	2	***Amortization of 2017 Revenue Surplus deferral account*** The Panel directs FEI to propose an amortization period for the 2017 Revenue Surplus deferral account as part of FEI's Annual Review for 2018 Delivery Rates Application.	Partial amortization has been proposed for 2019. Further amortization will be proposed in a future application.	Section 12.4.2.1
16.	19	8	***Forecasting Directive*** FEI is directed to report the Holt's Exponential Smoothing (ETS) test forecasts and the aggregate Mean Average Percent Error (MAPE) results as part of its annual review for 2018 delivery rates application and in all remaining annual review applications. FEI is also directed, as part of its future annual review application materials, to extend the applicable tables in Section 3 of Appendix A2 of the Application to include variance information for the ETS method for the residential and commercial use per customer, and the commercial customer additions.	Results reported.	Appendix A2 Section 3.18
17.	23	9	***Headcount Information*** FEI is directed to provide the headcount and Full Time Equivalent information as outlined in the Reasons for Decision attached as Appendix A to this order in its annual review for 2018 delivery rates application and in all remaining annual review applications during the term ofthe Performance Based Ratemaking Plan.	Information provided.	Appendix C3

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-25-17 – FEI ALL INCLUSIVE CODE OF CONDUCT AND TRANSFER PRICING POLICY					
18.	24	4	***Shared Services*** FEI is directed to file a review of its shared services model as part of its 2018 Annual Review under its Performance Based Rate Plan or alternatively, as part of its next revenue requirement proceeding.	The shared services model will be filed as part of FEI's 2020 revenue requirement/PBR filing.	N/A
G-196-17 – FEI ANNUAL REVIEW FOR 2018 RATES					
19.	10	-	***Capital Spending in Excess of the Dead-Band*** Given the ongoing issues with capital spending, the Panel directs FEI to continue to report on capital spending in the manner outlined in the FEI Annual Review for 2017 Delivery Rates Reasons for Decision, attached as Appendix A to Order G-182-16, for the remainder of the PBR term. These capital reporting requirements must include updating the information in Table 1-4 provided in the Application as well as updating the information in Appendix C4 to the Application.	Ongoing during PBR period	Table 1-4 and Appendix C4

As directed by the Commission, FEI provides below a table for each of the major productivity initiatives that FEI has implemented as discussed in Section 1.4, in the format requested by the Commission.

Table C2-1: Regionalization Initiative – Phase 1

	2014	2015+
Activities undertaken	• Operations Supervisor recruitment and training • Dispatcher relocation, recruitment and training • Planner relocations • Process review and modification • IT infrastructure and system modifications • Facilities modifications	None
Organizational changes	• Dispatch staff decreases • Operations staff increases due to hiring of Operations Supervisors • Operations staff decreases due to retirements and terminations not replaced • Planners staff re-allocated to Operations	None
O&M expenditures incurred or expected to be incurred	**$0.9 million** This included costs for a number of activities including employee development/ training, IT and facilities.	None
Capital expenditures incurred or expected to be incurred	**$1.3 million** This includes costs for IT, facilities and communications.	None
Anticipated savings	**$1.0 million** approximately. As discussed in the response to BCUC IR 1.2.1 in the annual review for 2015 delivery rates, it is difficult to separate Regionalization savings from the savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.	Ongoing

1 **Table C2-2: Regionalization Initiative – Phase 2**

	2016	2017+
Activities undertaken	• Regionalize pre-req, closing, and hazards functions closer to service areas • Process review and modification • IT infrastructure modifications • Facilities modifications	None
Organizational changes	• Operations support staff decreases • Operations support staff re-allocated to service areas	None
O&M expenditures incurred or expected to be incurred	**$0.8 million** This included costs for a number of activities including employee development/training, IT, facilities and communication	None
Capital expenditures incurred or expected to be incurred	**$0.7 million** This includes costs for IT and facilities and back office costs.	None
Anticipated savings - Labour	**$1.1 million** approximately. Similar to Phase 1, it is difficult to separate Regionalization savings from the savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.	Ongoing

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3 **Table C2-3: Project Blue Pencil**

	2014	2015	2016+
Processes Reviewed	High Bill Inquiry Emergency Collections Meter Exchange New Construction		
Organizational Changes	Contact center and billing operations will experience a FTE reduction as a result.	Contact center and billing operations will experience a FTE reduction as a result.	Contact center and billing operations will experience a FTE reduction as a result.
O&M expenditures expected to be incurred	$0 Incremental O&M costs	$0 Incremental O&M costs	$0 Incremental O&M costs
Capital expenditures expected to be incurred	<$100 thousand	<$200 thousand	$0
Annual Savings - Labour	< $100 thousand	Approximately $1 million annual contact centre and billing operations O&M savings.	Approximately $1 million annual contact center and billing operations O&M savings.
Annual Savings – non-Labour	$0	$0	$0

Table C2-4: Review of Technical and Infrastructure Support Provider

	2014	2015	2016+
Services Contract update and change	This is an initiative to review the existing agreement with the Company's technical and infrastructure service provider. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. This includes the employee Help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. For each permanent reduction in Compugen's costs to support FEI, the vendor and FEI share in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies. Additionally, the new contract provides dedicated support resources rather than a distributed support service resulting in quicker response times and better understanding of the Company's requirements.		
Organizational Changes	Contract awarded to Compugen after RFP process. Transitioned from incumbent third party provider, Telus, to successful bid proponent Compugen.	Compugen takes over support contract.	
Capital expenditures incurred	$1.1 million to replace the Service Request system that required replacement to complete the transition.	$400K to complete the project to replace the Service Request system.	$0
Annual Savings – non-Labour	$0	$1.8 million	$2 million

Table C2-5: Online Service Application

	2015 / 2016	2017+
Activities undertaken	• Development of internet based application using .net technology. • Interfaces with existing enterprise applications such as SAP, GIS, ClickSchedule, Café using Web Services and BizTalk.	None
Organizational changes	• None	None
O&M expenditures incurred or expected to be incurred	**$0.05 million** This included costs for analysis, training and change management.	$0.01 million
Capital expenditures incurred or expected to be incurred	**$1.8 million** This includes the costs for developing the application.	$0.5 million
Anticipated savings	This application is designed to enhance the customer experience by offering customers another channel to request a service line in addition to the existing customer contact centre voice channel.	$0.05 million annual O&M savings

Table C2-6: SAP Integration

	2017 and 2018	2019+

Activities undertaken	• Blueprint / Technical Design Phase
	• Realization Phase
	• Testing
	  ○ Regression Test
	  ○ Data Migration Test
	  ○ Integration Test
	  ○ Security Test
	  ○ User Acceptance Test
	• Cutover Phase & Go Live
	• Stabilization Phase
		None

Organizational changes	• Displacement of contractors with internal resources	None
O&M expenditures incurred or expected to be incurred	$0.3 million This included costs for Change Management support.	None
Capital expenditures incurred or expected to be incurred	$4.2 million This includes costs for implementation including build, test and deliver.	None
Anticipated savings	None in 2017 and 2018. Project completion is expected in the third quarter of 2018.	$0.9 million ($0.6 m FEI; $0.3 m FBC)

Table C2-7: Gas Workforce Management

	2017 - 2019	2020+
Activities undertaken	• Streamline and improve field work processes • Requirements and Design Workshops (3 rounds) • Change Management • Software Build • Software Test • User Acceptance Testing • Training • Go-live (late 2019) • Go-Live and post implementation support	Post implementation support
Organizational changes	• None	None
O&M expenditures incurred or expected to be incurred	$0.7 million This included costs for Change Management support.	None
Capital expenditures incurred or expected to be incurred	$5.8 million This includes costs for implementation including build, test and deliver.	None
Anticipated savings	Project completion is expected in late 2019. It will deliver improved safety, and customer experience, as well as simplify the user experience and reduce O&M.	$0.5 million annual O&M savings

Table C2-8: Common Trenching

	2018 and 2019	2020+
Activities undertaken	In collaboration with other shallow utility owners, developers, and customers, FEI is currently developing a program to install gas mains and multi-family services in conjunction with other underground infrastructure such as electric, telephone, and cable conduit. By installing gas infrastructure early and concurrently, FEI is able to increase onsite safety and improve customer service by decreasing construction time for customers and reducing development costs. Customers can get gas pipe installed earlier and FEI can reduce installation effort by avoiding conflicts with other utilities and surface infrastructure. Additionally, FEI expects the program may result in a reduction of installation costs over time. At this time, FEI is not able to estimate the level of savings that may be achieved. To date, FEI has completed four party trenching projects in the Fraser Valley, Okanagan and Vancouver Island. The projects have generated learnings and satisfied customers, as well as provided FEI with opportunities to determine best practices and improve the process.	
Organizational changes	• None	None

	2018 and 2019	2020+
O&M expenditures incurred or expected to be incurred	• Negligible	None
Anticipated savings	Program is currently under development with savings to be determined	Savings to be determined

On page 23 of Appendix A attached to Order G-182-16 approving FEI's Annual Review for 2017 Rate, the Commission provided the following directive:

> FEI is directed to provide the headcount and Full Time Equivalent information as outlined in the Reasons for Decision attached as Appendix A to this order in its annual review for 2018 delivery rates application and in all remaining annual review applications during the term of the Performance Based Ratemaking Plan.

As directed by the Commission, FEI provides below Table C3-1 with the headcount information and Table C3-2 with the FTE information by the various categories outlined by the Commission in Appendix A.

Table C3-1: Headcount

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Projected	2018 Projected
Total Annual Headcount	1,764	1,704	1,656	1,667	1,735	1,724	1,816
Change in Annual Headcount (year over year)	(1)	(60)	(48)	11	68	57	81
# of Positions Added Each Year (total) and broken down as follows:							
Regionalization Initiative - Phase 1 and 2	-	31	-	-	-	-	-
Project Blue Pencil	-	-	-	-	-	-	-
Other Major Initiatives	-	-	-	-	-	-	-
Outside of Base O&M	25	(4)	(5)	6	25	28	58
Inside Base O&M	(26)	(34)	(32)	23	43	28	23
Total Positions Added	(1)	(8)	(37)	30	68	57	81
# of Positions Eliminated Each Year (total) and broken down as follows:							
Regionalization Initiative - Phase 1 and 2	-	(52)	-	(19)	-	-	-
Project Blue Pencil	-	-	(10)	-	-	-	-
Other Major Initiatives	-	-	-	-	-	-	-
Outside of Base O&M	-	-	-	-	-	-	-
Tilbury Expansion	-	-	-	-	-	-	-
Biomethane and NGT	-	-	-	-	-	-	-
Charged to Capital	-	-	-	-	-	-	-
Charged to Deferral Accounts	-	-	-	-	-	-	-
CMAE	-	-	-	-	-	-	-
Affiliates	-	-	-	-	-	-	-
Inside Base O&M	-	-	-	-	-	-	-
Total Positions Eliminated	-	(52)	(10)	(19)	-	-	-
Net Change in Headcount (year over year)	(1)	(60)	(47)	11	68	57	81
# of Unfilled Vacancies							
# of Unfilled Vacancies for each year	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table C3-2: FTE

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Projected	2018 Projected
Total Annual FTEs	1,679	1,650	1,573	1,581	1,648	1,650	1,727
Change in Annual FTEs (year over year)	(3)	(29)	(77)	8	67	69	79
# of Positions Added Each Year (total) and broken down as follows:							
Regionalization Initiative - Phase 1 and 2		31					
Project Blue Pencil							
Other Major Initiatives							
Outside of Base O&M	25	(4)	(5)	6	25	28	58
Inside Base O&M	(28)	(3)	(62)	21	42	40	21
Total Positions Added	(3)	23	(67)	27	67	69	79
# of Positions Eliminated Each Year (total) and broken down as follows:							
Regionalization Initiative - Phase 1 and 2		(52)		(19)			
Project Blue Pencil			(10)				
Other Major Initiatives							
Outside of Base O&M	-	-	-	-	-	-	-
Tilbury Expansion							
Biomethane and NGT							
Charged to Capital							
Charged to Deferral Accounts							
CMAE							
Affiliates							
Inside Base O&M							
Total Positions Eliminated	-	(52)	(10)	(19)	-	-	-
Net Change in FTE - year over year	(3)	(29)	(77)	8	67	69	79
# of Unfilled Vacancies - included related to O&M, Capital, Other							
# of Unfilled Vacancies for each year	19	30	39	51	50	n/a	n/a

Overview of Approach to Preparing the Information Requested

The numbers provided in the tables above are FEI's approximation of the changes in headcount and FTE by the different classifications (Regionalization Initiative, Project Blue Pencil, Other Major Initiatives, Outside Base O&M, Inside Base O&M, etc.) as outlined in the format provided by the Commission in Appendix A to Order G-182-16.

FEI does not track and report headcount and FTEs in the classifications outlined by the Commission. FEI's Human Resources systems track employees and the positions that they occupy and which part of the organization they belong to. In addition, the systems track changes in the status of positions, positions added and removed. The position changes tracked in the systems include the transfers of positions from one department to another, even though the changes do not necessarily represent true net changes to the organizational overall.

Reporting on the classifications requested by headcount and FTEs is inherently difficult. An employee, depending upon their job responsibilities, may perform a number of activities that fall into the different classifications outlined. For example, an employee may spend 80% of their time performing O&M activities with the remaining 20% of their time on capital activities. On an FTE basis, 0.80 FTE would be reported as O&M and 0.20 FTE reported as Capital. However, a headcount cannot be split, so the headcount can be reported as either O&M or Capital, but not partly O&M and partly Capital. As a result, the headcount information provided in Table C3-1 above has been completed in a similar manner to that reported on an FTE basis in Table C3-2 (i.e., one FTE equals one headcount). Where there are differences between the headcount and FTE information (which are typically caused by vacancies within a given period and the use of part-time and temporary employees), for the purpose of the information requested, the differences are reported as part of the Inside Base O&M classification, recognizing that the Inside Base O&M classification accounts for the majority of headcount and FTE at FEI.

With the limitations described, FEI's approach to generating the information requested by the Commission was to first approximate the changes in FTEs by the broad classifications (i.e. Inside Base O&M, Outside Base O&M). This was estimated using financial and costing data in FEI's SAP system. The financial data was then converted to FTEs using average annual wage/salary assumptions for different employee affiliations (i.e. M&E, IBEW, MoveUp). Reporting by specific initiatives (i.e. Regionalization, Project Blue Pencil) was based on additional headcount and FTE information available, as the headcount and FTE changes were tracked separately for some initiatives. Adjustments to the FTEs reported for the broad classifications (i.e. Inside Base O&M, Outside Base O&M) were made to avoid double-counting of the changes.

Separating the FTE changes into Additions and Deletions is not possible given the existing systems and information available. Changes in FTEs can occur for different reasons, including new positions, positions eliminated, turnover of staff (i.e. vacancies) and changes in the how much time is allocated between one activity versus another (O&M versus Capital). As a result, FEI was only able to separate Additions from Deletions for the Regionalization and Blue Pencil initiatives, as these were the only ones where the information was tracked separately. Therefore, other than for these two initiatives, the information requested is reported on a Net Change basis.

With regards to the "# Unfilled Vacancies" information requested, FEI understands "Unfilled Vacancies" to mean existing positons that become temporarily vacant due to turnover. For FEI, the proxy to measure this is by taking the number of job bulletins identified as for "replacement" in a given year and calculating how long the job bulletins are vacant for. The days vacant estimated are then converted to an FTE basis. However, FEI is unable to determine specifically for all the job vacancies in a given year, how many are related to the different classifications (i.e. O&M, Capital), or whether in the interim the vacancy was filled by use of a contractor or a consultant, or by additional overtime (unpaid or paid) by existing employees. Due to the difficulties described, FEI has not forecast Unfilled Vacancies (i.e. 2017 and 2018 Projected).

Given the above circumstances and assumptions, the headcount and FTE information provided are approximations only. The information is indicative of factors contributing to headcount and FTE changes, instead of having a direct and accurate correlation to costs incurred and savings realized.

1. INTRODUCTION

In Order G-196-17, at page 10, the Commission provides the following directive.

> The Panel directs FEI to continue to report on capital spending in the manner outlined in the FEI Annual Review for 2017 Delivery Rates Reasons for Decision, attached as Appendix A to Order G-182-16, for the remainder of the PBR Plan term.[1] These capital reporting requirements must include updating the information in Table 1-4 provided in the Application as well as updating the information in Appendix C4 to the Application.

In Order G-182-16, at page 17, the Commission set out the following capital directives.

> The Panel directs FEI to provide the following information in its annual review for 2018 delivery rates application:
>
> - The information contained in Table 1-3 of the Application updated for 2016 Actuals and Projected 2017 results;
> - A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Growth Capital, which separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any);
> - A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Sustainment/Other Capital, which separately quantifies the amount of the annual variances and cumulative variance attributable to: (i) the reduction to the Base Sustainment Capital for the Vancouver Island region; (ii) the growth factor for net customer additions; (iii) the Regionalization Initiative; (iv) the installation of Jomar valves; (v) increased in-line inspection activity; (vi) unanticipated system improvements and new stations to supply gas to large new customers; (vii) Burns Bog Stress Relief; and (viii) other contributing factors (if any); and
> - A description of how FEI is prioritizing its capital expenditures during the remainder of the PBR term, with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken

[1] FEI Annual Review for 2017 Delivery Rates, Order G-182-16 and Reasons for Decision, dated December 7, 2017, Appendix A, p. 17.

> during the PBR term. FEI must also provide a description of any projects which it had originally planned to complete during the PBR term but are now expected to be delayed until after the PBR term.

FEI included an updated Table 1-4 in Section 1 of the Application. In this Appendix, FEI provides the requested information for each of the remaining areas described in Order G-182-16.

2. ANNUAL GROWTH CAPITAL VARIANCES

This section provides annual and cumulative variances between formula and actual/projected growth capital broken down into mains growth capital and service line additions growth capital. In its directive, the Commission requested information which includes a breakdown and explanation for both the annual variances and the cumulative variance between formula and actual/projected growth capital, and separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any). As shown in Table 1-4 of the Application, the cumulative growth capital variance for the 2014 to 2018 period is projected to be $90.78 million. The service line additions growth capital variance discussed in Section 2.1 below totals $66.8 million, and the mains growth capital variance discussed in Section 2.2 below totals $21.1 million. These two amounts sum to $87.9 million of the $90.78 million cumulative growth capital variance.

The growth capital variances are attributable to two main factors: (1) an increase in the volume of service and main installations, and (2) a higher per installation cost than was utilized in calculating the approved formula growth capital amounts. FEI's Base Capital costs for the PBR period were based on the 2013 Approved (for FEI) and 2014 Approved (for Vancouver Island and Whistler) growth capital costs, which were in turn based on 2010 actual costs for FEI and 2012 actual costs for Vancouver Island and Whistler. Since that time, FEI has seen a substantial increase in the number of services and mains installed to meet customer demand, and an increase in installation costs. As a result, overall growth capital expenditures are higher than what the PBR formula allows.

It is important to note that, for growth capital, each customer must pass an extension test in order to attach to the system. This test is either a service line cost allowance test or a main extension test. If the customer passes this test, or elects to pay a contribution if they do not pass the test, FEI is obligated to provide service to the customer[2]. These tests do not consider restrictions on capital spending, whether through a PBR formula or otherwise. Further, in the case of particularly large mains, costs may be high, but offsetting revenues may be high as well. Thus, higher capital expenditures may be offset by higher revenue. As noted in the regulatory proceeding to review FEI's system extension policies, the addition of customers from 2008-2014 has had a positive effect on rates, since new customers pay more than their cost to serve.

Variances attributed to service line addition growth capital and mains growth capital are further explained below.

[2] Section 28 (1) of the Utilities Commission Act: On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose.

2.1 SERVICE LINE ADDITIONS GROWTH CAPITAL VARIANCE

To determine the annual and cumulative variance from service lines additions FEI first had to determine the approved capital amount for service line additions embedded in growth capital. The following table shows the break out of approved growth capital split by Mains, Meters and Service Line Additions (SLAs). As shown in Table C4-1, the cumulative approved formulaic capital for SLAs is $94.6 million.

Table C4-1: Components of Approved Growth Capital ($000s)

Line No.	Year	Approved Growth Capital	Growth Capital for Mains	Growth Capital for Meters	Growth Capital for SLAs
1	2014 A	$ 21,479	$ 6,490	$ 2,102	$ 12,886
2	2015 A	28,480	8,672	2,312	17,495
3	2016 A	33,262	10,129	2,700	20,432
4	2017 A	33,477	10,194	2,718	20,565
5	2018 P	37,485	11,284	3,008	23,192
6	**Cumulative**	**$ 154,182**	**$ 46,770**	**$ 12,841**	**$ 94,572**

The following Table C4-2 shows the total capital variance and then splits the total variance into activity and cost components.

Table C4-2: Service Line Addition and Capital Variances ($000s unless otherwise noted)

		Approved			*Actual*			*Variance*	
Line No.	**Year**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**Capital**
1	2014 A	7,934	$ 1,624	$ 12,886	8,473	$ 2,096	$ 17,762	539	$ 4,876
2	2015 A	9,586	$ 1,825	$ 17,495	12,392	$ 2,430	$ 30,110	2,806	$ 12,615
3	2016 A	11,143	$ 1,834	$ 20,432	12,288	$ 2,546	$ 31,291	1,145	$ 10,859
4	2017 A	11,180	$ 1,840	$ 20,565	15,856	$ 2,497	$ 39,594	4,676	$ 19,029
5	2018 P	12,443	$ 1,864	$ 23,192	16,408	$ 2,595	$ 42,576	3,965	$ 19,383
6	**Cumulative**	**52,286**	**$ 1,809**	**$ 94,572**	**65,417**	**$ 2,466**	**$ 161,334**	**13,131**	**$ 66,762**
7									

8		*Activity Variance (Approved)*			*Cost Variance*			*Variance*
9	**Year**	**SLAs Variance**	**Approved $/SLA**	**Capital Variance from # SLAs**	**Actual SLAs**	**$/SLA Variance**	**Capital Variance from Cost per SLA**	**Capital**
10	2014 A	539	$ 1,624	$ 875	8,473	$ 472	$ 4,001	$ 4,876
11	2015 A	2,806	$ 1,825	$ 5,122	12,392	$ 605	$ 7,493	$ 12,615
12	2016 A	1,145	$ 1,834	$ 2,099	12,288	$ 713	$ 8,760	$ 10,859
13	2017 A	4,676	$ 1,840	$ 8,603	15,856	$ 658	$ 10,426	$ 19,029
14	2018 P	3,965	$ 1,864	$ 7,390	16,408	$ 731	$ 11,993	$ 19,383
15	**Cumulative**	**13,131**		**$ 24,089**	**65,417**		**$ 42,673**	**$ 66,762**

2.1.1 Growth Factor for Service Line Additions

The variance in approved versus actual, for both SLAs and overall capital, is impacted by the PBR formula which uses a historical growth factor to determine the future years approved capital expenditures, in addition to the growth formula accounting for only one half of growth[3]. As a result, the PBR formula does not accurately account for the actual number of service line additions. Line 15 from Table C4-2 shows that FEI has installed 13,131[4] more service lines than the formula contemplated, which accounts for $24.1 million of the total variance.

2.1.2 Other Factors Contributing to the Variance for Service Line Additions

As shown in line 15 of Table C4-2, overall service line attachments were higher than the formula allowed. Line 6 also shows that the actual average cost per SLA is $657 per SLA higher than the formula approved amount ($2,466 - $1,809). Consistent with the factors discussed in Appendix C4 Capital Directives of the 2018 Annual Review filing last year, the primary factors that have changed since the base capital per SLA amounts were developed, and that are contributing to the cost per service line variance include:

- An increase in customer attachments per service line, which results in a higher cost per service line addition;
- An increase in SLA activity on Vancouver Island (where costs are higher), compared to the SLA activity in the growth capital formula;
- An unfavourable USD exchange rate that has resulted in an increased cost of equipment and supplies purchased from the United States; and
- Local government requirements.

These contributing factors are described in more detail below.

2.1.2.1 Increase in Customer Attachments per Service Line Addition

Due to the changing housing market from single detached homes to multi-family developments, FEI is seeing an increase in the number of customer attachments per SLA. In the case of a single detached home, there is generally one customer attachment per SLA. In the case of a multi-family development, there can be upwards of 10 to 40 customers attaching to a single service line. For example, in 2012 there were approximately 1.2 customers per SLA, whereas in 2016 there were approximately 1.4 customers per SLA. The average customer attachment per SLA ratio for the past three year period (2015-2017) has been approximately 1.34. To serve

[3] FEI has calculated the impact on Total Capital of the growth factors for SLAs and net customer additions being reduced by half in Section 1.4.4.1. In addition, FEI is compensated for the use of an historical growth level instead of actual through the earnings sharing mechanism, but the capital formula itself is not adjusted for the lag. The adjustment to the earnings sharing mechanism is described in Section 10.1.2.

[4] 2014 – 2017 Actual plus 2018 Projection

a single detached home requires smaller pipe, fewer fittings, and a smaller riser resulting in a lower cost per service line attachment compared to the cost to serve a multi-family development, which requires a service line attachment with larger pipe, additional fittings and a larger riser contributing to a higher SLA cost.

2.1.2.2 SLA Activity on Vancouver Island and the Cost per Service Line Addition

The cost variance is due in part to the increase in SLA activity on Vancouver Island compared to the SLA activity in the growth capital formula. When the Vancouver Island and Whistler service areas were amalgamated with FEI, the 2014 growth capital base was adjusted for both the number of SLAs and the cost per SLA for Vancouver Island (and Whistler). At that time, the Vancouver Island SLA adjustment added 2,167 SLAs, which represented 21 percent of the total 2014 SLAs of 10,156. In 2015, 2016, 2017 and projected for 2018, FEI is experiencing increased SLAs on Vancouver Island compared to those in the base (26 percent, 29 percent, 28 percent and 36% percent of total SLAs in 2015, 2016, 2017 and 2018, respectively). The increase in this activity on Vancouver Island at a higher cost per SLA than the Mainland is a contributing factor to the cost variances attributed to SLAs.

2.1.2.3 USD Exchange Rates

The Canada-United States exchange rate forecast, on which FEI based its capital cost assumptions for the PBR term, was higher than the exchange rates that have been realized during the PBR term. FEI's Base Capital for the PBR plan was set at FEI's 2013 Approved levels, with additions for Vancouver Island and Whistler based on 2014 Approved expenditures, following the amalgamation of the companies. FEI's 2013 Approved capital expenditures were based on a CAD/USD exchange rate forecast of $0.97 and Vancouver Island (and Whistler) Approved capital expenditures in 2014 were based on a CAD/USD exchange rate of $0.99. Thus, FEI's Base Capital was set based on an expectation that the exchange rate would be close to par, whereas capital expenditures during the PBR term have been incurred at an exchange rate closer to 0.8[5]. This causes capital cost pressure on FEI's formula-driven expenditures under the PBR plan.

2.1.2.4 Evolving Local Government Requirements

Local governments have implemented regulations that place increased requirements on utilities. FEI is continuing to work with local governments and regulators to meet evolving municipal regulations. Additional permitting requirements, working arrangements and restricted working hours have added additional cost pressures to growth capital.

[5] Average 2014 through 2018 Bank of Canada indicative CAD/USD exchange rate (2014: 0.91, 2015: 0.78, 2016: 0.76, 2017: 0.77 , 2018: 0.78)

2.2 MAINS GROWTH CAPITAL VARIANCE

As noted in the preamble to the discussion on growth capital, FEI is experiencing strong customer growth in both service lines and in mains with more residential developments which require main extensions, but also a number of larger mains required for commercial/industrial customers.

The annual and cumulative variances between formula and actual/projected capital is provided for total New Customer Mains as shown in Table C4-3 below. FEI is currently projecting mains expenditures in 2018 to be significantly higher to those of 2017 resulting from a steep increase in activity in early 2018. FEI has seen an increase in mains activity (as at May end) of approximately 54 percent, which resulted in an additional 33,682 meters of main installed compared to same period last year.

Table C4-3: New Customer Mains ($ thousands)

New Customer Mains (000's)	Actual/ Projected	Allowed	Variance	Var%
2014	5,399	6,649	(1,250)	-19%
2015	14,082	9,007	5,075	56%
2016	13,103	10,444	2,659	25%
2017	16,654	10,400	6,253	60%
2018	20,017	11,657	8,361	72%
Cumulative	69,254	48,156	21,098	44%

The variance in costs for customer mains is driven partly by the growth in large industrial mains, and a number of other factors as outlined in section 2.2.2 below.

2.2.1 Growth in Larger Industrial Main Additions

FEI does not have a capital formula specific to larger industrial mains so is not able to directly quantify the amount of the variance due to this factor. Instead, FEI provides the following discussion of larger mains.

The average cost per metre of main in FEI's 2013 Base was $62 per metre. The actual cost per metre of main was $87 in 2014, $121 in 2015, $121 in 2016, $110 in 2017, with 2018 expected to be an average of 2016 and 2017 unit costs. The 2014 through 2018 costs have been influenced upward by a number of larger cost mains. The 34 mains with the highest cost per metre that FEI has installed since 2014 had an average cost per metre of $308, which has contributed approximately $5.8 million to date to the capital cost pressure when compared to the average cost that was embedded in the PBR formula.

In 2010, the year that was used to develop the 2013 Base for the PBR formula, there was one new main with a cost greater than $100 thousand. This compares to 15 and 11 new mains greater than $100 thousand in 2015 and 2016, respectively. The number of larger new mains (greater than $50 thousand) has more than doubled in 2015 and 2016 compared to that of

2014. In 2017, FEI installed approximately 400 meters of new main for a customer that was more than seven times the average unit cost of $110 per metre of main. Several factors contributed to the higher unit cost for the main installation including complexity of the service renewals, additional costs associated with maintaining road access to the fire hall and additional paving costs requested by the city.

FEI mains expenditures are driven by customer growth and the type of customer impacts the timing, size and cost of the mains. The decision by large industrial customers to connect to FEI's system, their load profile and the location they wish to connect to are largely driven by factors outside the control of FEI. Larger diameter and more costly mains to serve customer load requirements, in addition to a significantly larger number of main installations compared to previous years, have contributed to variances in growth capital.

2.2.2 Other Factors Contributing to the Variance for Mains

Some of the cost pressures contributing to the SLA growth capital variance also contribute to the Mains growth capital variance. An increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate and local government requirements are contributing to the mains growth capital cost variance.

3. ANNUAL SUSTAINMENT/OTHER CAPITAL VARIANCES

In Table C4-4 below, FEI provides a breakdown and itemization of variances attributable to the items identified by the Commission.

Table C4-4: Annual Sustainment/Other Capital Variances ($ millions)[6]

Line No.	Description	2014	2015	2016	2017	Forecast 2018	Cumulative
1	PBR Decision reduction to base sustainment capital for Vancouver Island pressure	-	6.351	6.417	6.484	6.567	25.820
2	PBR Decision growth factor for net customer additions pressure	0.259	0.939	1.586	2.250	3.234	8.269
3	Regionalization Initiative	1.300	0.100	0.600	-	-	2.000
4	Installation of bypass (Jomar) valves	-	0.050	2.070	2.590	3.400	8.110
5	Increased in-line inspection activity	1.944	1.295	3.287	1.719	4.824	13.069
6	Unanticipated system improvements and new stations to supply gas to new customers	0.600	2.700	1.764	1.901	7.403	14.368
7	Burns Bog stress relief	0.300	1.800	1.000	2.827	-	5.927
8	Other contributing factors:						
9	PBR formula pressures resulting from increase in PIF (1.1% vs. 0.5%)	0.597	0.664	0.669	0.676	0.684	3.290
10	Prince George #1 lateral erosion	0.150	0.030	0.040	0.682	-	0.902
12	Ministry of Transportation and Infrastructure IP relocation		0.050	0.700		-	0.750
13	Mission IP seismic upgrade		1.200			-	1.200
14	Ashcroft Lateral Pipeline replacement due to flood erosion				1.308	0.980	2.288
15	Cyber security				0.423	0.500	0.923
16	**TOTAL Sustainment / Other Pressures**	5.150	15.180	18.134	20.860	27.592	86.916
17	**Actual annual and cumulative Sustainment / Other capital expenditures variance compared to formula**	1.825	(3.098)	2.588	26.311	31.664	59.291

Notes:
1. PBR formula pressures related to reduction to base sustainment capital for Vancouver Island.
2. PBR formula pressures resulting from 50% of net service additions.

Table C4-4 shows that the pressures experienced in years 2014 through 2016 are greater than FEI's annual sustainment and other capital expenditures over formula in those years. As explained elsewhere, in order to manage pressures experienced during years 2014 to 2016 of the PBR term, some projects that were assessed as being less critical to the system, or that were temporarily less time-sensitive, were reprioritized to future years to accommodate the required projects listed in the table. In 2017 and 2018, FEI has prioritized additional capital expenditures to start to catch-up on an accumulation of work that had been re-prioritized from previous years of the PBR term into later years. For this reason, FEI's cumulative sustainment and other capital expenditure compared to formula is higher in 2017 and 2018 than the total of the items shown in Table C4-4.

[6] Table C4-4 presented in the 2018 Annual Review line 8 incorrectly noted values in 2014, 2015 and 2017. This amendment does not change the variance explanation.

FEI provides below a further discussion of each of the 2018 items in the table above, other than the formula-related items which are self-explanatory. Pressures for 2014 through 2017 were described in Appendix C-4 of FEI's 2018 Annual Review.

3.1 INSTALLATION OF BYPASS (JOMAR) VALVES

The installation of bypass valves (Jomar Valves) on residential meter sets was described further in Section 3.2, Appendix C4 of FEI's 2018 Annual Review Application.

3.2 INCREASED IN-LINE INSPECTION ACTIVITY

As described in Section 3.3, Appendix C4 of FEI's 2018 Annual Review Application, FEI needs to continue to enhance its Integrity Management Program to manage aging infrastructure, meet the CSA Z662-15 standard, and adopt industry practices deemed appropriate to FEI's system. Enhancements to FEI's in-line inspection activities include the adoption of the circumferential magnetic flux leakage technology with a run frequency of approximately 7 years, and an increased number of transmission lines subject to in-line inspection.

3.3 UNANTICIPATED SYSTEM IMPROVEMENTS AND NEW STATIONS TO SUPPLY GAS TO NEW CUSTOMERS

As described in Section 3.4, Appendix C4 of FEI's 2018 Annual Review Application, FEI forecasts the need for system capacity improvements due to typical growth of core customer load over 5-10 years using system capacity models. These forecasts make assumptions regarding the magnitude and location of load additions to the system based on housing development and growth trends known at the time. The higher than expected customer growth that has taken place during the PBR term, and the addition of large new customers has resulted in the need for system improvements and new stations to support the added load described in section 2. The need for capacity upgrades to the system has been well in excess of what was anticipated at the time of the PBR Application filing.

3.4 OTHER CONTRIBUTING FACTORS

In addition to the PBR formula pressures discussed in Section 1.4 of the Application, FEI has identified the following other contributing factors.

3.4.1 Ashcroft Lateral Pipeline Replacement Due to Flood Erosion

In the spring of 2017, flooding in the Ashcroft area caused Cache Creek to leave its previous channel and create a new channel that eroded the ground cover over the Ashcroft Lateral NPS 88 pipeline. Approximately 150 metres of pipeline needed to be replaced and lowered below the new creek profile. Further flooding in the spring of 2018 exposed additional sections of the pipeline. Planning is underway to restore ground cover this year and protect the pipeline from further damage.

3.4.2 Cyber Security

In 2017, FEI is implementing cyber security measures to protect networks, computers and data from attack, theft, damage or unauthorized access. This initiative is described in more detail in Section 1.3.1.

3.4.3 CAD-USD Exchange Rates

This item was discussed above in Section 2.1.2.3. An increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate is contributing to the sustainment / other capital cost variance.

3.4.4 Evolving Local Government Requirements

This item was discussed above in Section 2.1.2.4. An estimate of the pressures attributable to this item was not included in Table C4-4 as it is difficult to quantify.

4. CAPITAL PRIORITIZATION

In this section, FEI provides a discussion of how capital expenditures will be prioritized during the remainder of the PBR term. This includes a description of any projects which were originally planned to be completed during the PBR term but are now expected to be delayed until after the PBR term.

As the gas delivery infrastructure continues to age, the need to invest in sustaining the system continues to increase. These investment needs must in turn compete with other investments to:

- maintain or increase system reliability and resilience;
- improve employee and public safety;
- add new customers;
- meet changing regulatory requirements and industry practice; or
- leverage new technologies.

FEI recognizes the need for continual improvement in prioritizing investments and for more transparency in ensuring that all investments create value for the customer. As such, FEI continues to align processes across the organization in its capital planning to help achieve the highest level of benefit for the available funds and resources. FEI provides below a description of its capital expenditure prioritization processes.

4.1 *CAPITAL PRIORITIZATION PROCESS*

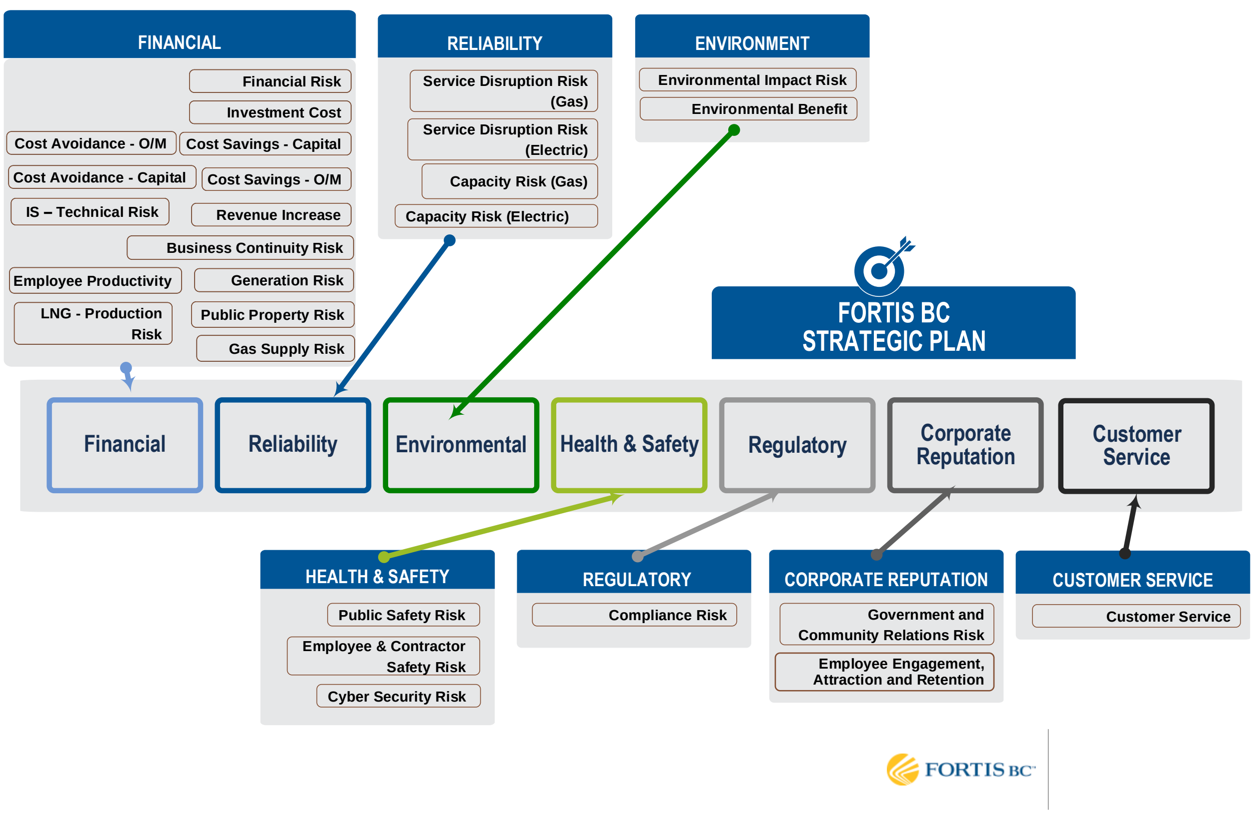
FEI manages its capital investment plan to maintain a safe and reliable gas delivery system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan is built to contain a mix of projects, some of which are time-sensitive and others that have some flexibility in timing. This is done with the understanding that conditions change and the plan must be capable of adapting. This plan flexibility allows FEI to manage and execute normal levels of unforeseen urgent work that come up throughout the year within the resource and budget constraints of the capital plan.

In recognition of the importance of consistently valuing and prioritizing its investments, and in light of recent capital pressures that are expected to continue, FEI has been building on and enhancing its capital planning process to further align capital investment decision-making across the Company and leverage the available tools, processes and systems.

In 2017, FEI implemented the first phase of an Asset Investment Planning (AIP) tool[7]. The scope of implementation included the installation of Copperleaf C55 software and the development of processes and methodologies to support the consistent quantification of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types in the Gas Sustainment portfolio. The second phase of implementation is currently underway and includes Electric Sustainment, Information Systems, Fleet, and Facilities.

The foundation of the AIP tool is the value framework that is used to quantify the value of potential investments. The value framework is made up of seven overarching values that were derived from FEI's strategic objectives and core values. They are: financial, reliability, environmental, health & safety, regulatory, corporate reputation, and customer service. Under each value, there are measures which contribute to and impact each value. These measures, and which value they impact, are shown below in Figure C4-2.

Figure C4-2: Value Measures for Asset Investment Planning Tool



Each project is evaluated against one or more of the measures that will be impacted by undertaking the project:

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[7] Phase 1 applies to Gas asset management and to information systems. General plant and Electric asset management will be part of future phases.

- Health & Safety values measure a project's impact on improving the safety of our employees, contractors, customers, and the public by making the system safer to work on and reducing the probability of high consequence events;
- Environmental values measure a project's impact on reducing the probability of environmental incidents and/or reducing FEI's environmental footprint through energy efficiency and GHG emission reductions;
- Customer Service values measure a project's impact on meeting the needs of our customers through improved communication, problem resolution, and overall customer experience;
- Regulatory values measure a project's impact on maintaining compliance to all applicable codes and standards;
- Reliability values measure a project's impact on maintaining or improving reliability of service to customers by reducing the probability and/or severity of outages, and improving the ability of FEI to maintain the system without disrupting customers.
- Financial values measure a project's impact on cost efficiency or cost reduction by reducing operating costs, avoiding future costs, or avoiding costly unplanned expenditures; and
- Corporate Reputation values measure a project's impact on FEI's relationships with employees, governments, communities, and other stakeholders that FEI does business with.

The value that a capital investment contributes to each of these areas is calculated taking into account the number of customers, employees or other stakeholders impacted, the magnitude of a potential event, the likelihood that an event will occur, the mitigating factors that are present and the impacts of time on risks and benefits.

The portfolio is optimized and projects are planned for execution to achieve the greatest overall value. This provides a consistent and transparent method of valuing and prioritizing capital work across asset classes within the organization. It also ensures that the investment decisions being made support FEI strategic priorities for the benefit of customers and stakeholders.

This methodology is used to develop the capital sustainment plan, as well as to manage and modify the plan on an ongoing basis as conditions change. The capital sustainment plan is developed based on the scope of proposed investments, their value, and their cost estimate and spend profile at the time the plan is developed. The addition of unplanned capital work to the portfolio, or a change to the scope, schedule, value, or cost of any investment in the portfolio could lead to the reprioritization of work within the plan to advance or delay projects to meet the stated objectives of the plan within a set of financial and resource constraints.

Once fully implemented, the AIP tool will provide the following benefits:

- Increased ability to make risk-informed decisions in capital planning by valuing investments through a common value framework;
- Ability to show consistent methodology across asset classes in valuing capital projects;
- Increased transparency and ability to communicate the value being achieved through execution of the capital plan; and
- Improved ability to optimize the portfolio over multiple years and to consider alternative constraint scenarios.

4.2 *PROJECTS PLANNED TO BE UNDERTAKEN OUTSIDE OF PBR TERM*

The management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints. FEI reprioritizes capital spending as part of its routine management of the capital portfolio and has done so in prior years to accommodate unforeseen events and work, and to mitigate in part some of the pressures seen in the past years of PBR term. However, FEI will not defer significant amounts of capital spending that would result in increased risk exposure.

FEI continuously manages its capital investment plan to achieve the values stated in section 4.1. In order to achieve these goals, some projects that provide less value, or that are less time-sensitive, may be reprioritized to future years in favour of more urgent or valuable projects. Likewise, if additional capital is made available through project delays or cost savings, projects may be brought forward based on their assessed value and their ability to be successfully executed.

The base capital amount and annual formula adjustments were not derived from a list of future capital projects FEI planned to undertake each year during the PBR term. Rather, they were based on 2013 forecasts derived from historical capital expenditures. As such, FEI is unable to provide a comprehensive listing of projects that have been delayed, rescheduled, cancelled or added today against what was anticipated when the formula was developed. However, the following is a list of the larger projects that FEI had identified for execution in the PBR Application and has delayed beyond the PBR term.

Table C4-5: Projects Delayed to Beyond the PBR Term

Description	Estimated Timing	Current Status
Class Location Upgrade: 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston	2016	Planned for 2022
Class Location Upgrade: 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk	2017	Planned for 2022

Description	Estimated Timing	Current Status
Class Location Upgrade: 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks	2018	Planned for 2022
Tilbury LNG Plant Buildings	2018	Delayed to assess business requirements.
Distribution Main, Service Renewals and Alterations: Penticton Second Supply – Penticton	2015	Planned for 2020. Reprioritized due to capital constraints and to allow routing and siting review with the City of Penticton.
The addition of pipe storage to the Burnaby Operations building	2014	Delayed due to further review of requirements for space strategy.

As described in the PBR Application[8], FEI developed a forecast of Information Systems expenditures for the PBR period to allow for the implementation of projects to improve employee and public safety, address potential shortcomings in customer service levels and to drive O&M cost reductions. Information Systems expenditures are categorized under five main areas of focus including infrastructure sustainment, desktop infrastructure sustainment, application sustainment, business technology transformation and business technology enhancements. The annual portfolio under each category is continually evolving and individual projects are added or removed from the portfolio as required by the business. Each year is considered to be a new portfolio and projects are re-evaluated. FEI does not have any IS projects that have been deferred to outside the PBR term.

4.3 SUMMARY

FEI has taken a number of steps over the years to enhance and strengthen its internal capital prioritization processes. The AIP tool will allow the consistent quantification and evaluation of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

The management of the capital plan is a dynamic and ongoing process. Changing conditions make it essential to routinely assess and re-optimize the capital planning portfolio in order to achieve the greatest benefit within a set of user-defined financial and/or resource constraints.

As FEI implements the second phase of the AIP tool over the remaining term of the PBR plan, FEI anticipates an improved ability to optimize the portfolio in a transparent way over multiple years and to communicate the value being achieved through execution of the capital plan.

[8] Table C4-22, Section 4.6.4 of the PBR Application.

Appendix D

DRAFT ORDER

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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Annual Review of 2019 Delivery Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On September 15, 2014, the British Columbia Utilities Commission (Commission) issued its Decision and Order G-138-14 approving for FortisBC Energy Inc. (FEI) a Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2019 (the PBR Decision). In accordance with the PBR Decision, FEI is to conduct an Annual Review process to set rates for each year;

B. By letter dated July 26, 2018, FEI proposed a regulatory timetable for its annual review of 2019 delivery rates;

C. By Order G-142-18 dated July 31, 2018, the Commission established the regulatory timetable for the annual review of 2019 delivery rates which included the anticipated date for FEI to file its annual review materials, the deadline for intervener registration, one round of information requests, a workshop, FEI's response to undertakings requested at the workshop, and written final and reply arguments;

D. On August 3, 2018, FEI submitted its Annual Review for 2019 Rates Application materials (Application);

E. The Commission has reviewed the Application and evidence filed in the proceeding and makes the following determinations.

NOW THEREFORE the Commission orders as follows:

1. FortisBC Energy Inc. (FE) is approved to maintain 2019 delivery rates at the approved 2018 levels, before consideration of rate riders, effective January 1, 2019.

2. The following deferral account requests are approved:

a. Creation of a rate base deferral account for the 2019-2022 Demand Side Management Expenditures regulatory proceeding with a four-year amortization period.

b. Amendment of the existing rate base 2017 Long-Term Resource Plan Application deferral account to also capture the regulatory proceeding costs related to the Application, as well as a three-year amortization commencing in 2019.

c. A five-year amortization period for the existing 2017 Rate Design Application deferral account, commencing in 2019.

d. Creation of a non-rate base deferral account, attracting a weighted average cost of capital (WACC) return, for the development costs related to Transmission Integrity Management Capabilities (TIMC), with disposition to be proposed in a future application.

e. Partial amortization of the 2017-2018 Revenue Surplus account in the amount of $3.075 million, which will result in a total 2019 forecasted revenue deficiency/surplus of zero. FEI will provide a similar request in future applications until the balance in the account is drawn-down to zero.

3. The following rate rider requests are approved:

   a. A Biomethane Variance Account Rate Rider for 2019 in the amount of $0.018 per gigajoule; and

   b. Revenue Stabilization Adjustment Mechanism riders for 2019 in the amounts set out in Table 10-10 of the Application in Section 12.2.2.

4. FEI is approved to continue debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million for 2019, as described in Section 5.3.2 of the Application.

5. Z-factor treatment for the 2019 Employer Health Tax and 2018 and 2019 MSP premium reductions, as described in Section 12.2 of the Application.

6. Approval to recognize cloud computing implementation costs to be capitalized consistent with traditional on premise hardware and software for 2019 as described in Section 12.3.1.2.

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