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August 2, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

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 2017 Rates

In accordance with the PBR Plan and Commission Order G-122-16 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2017 Rates Application materials.

Should further information be required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FEI's PBR Proceeding

FortisBC Energy Inc.

Multi-Year Performance Based Ratemaking Plan

for 2014 through 2019

Annual Review for 2017 Rates

Volume 1 - Application

August 2, 2016

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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 third annual review of the PBR Plan and set FEI's delivery rates for 2017.

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, any 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 2016 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 O&M and capital savings. Overall, FEI proposes to distribute $5.115 million[2] in earnings sharing to customers in 2017. FEI has 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 2017 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 1.2 percent increase over 2016 delivery rates, or an increase of approximately $7 to the annual bill for an average Mainland residential customer.[3] After consideration of the delivery rate riders which are primarily related to amalgamation, the bill impact change is an increase of approximately 4.6 percent for a Mainland residential customer, a decrease of approximately 6.0 percent for a Vancouver Island residential customer, and a decrease of approximately 12.6 percent for a Whistler residential customer. The delivery rate increase of 1.2 percent before delivery rate riders is below 2017 inflation which is forecast at approximately 2.2 percent.[4]

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 2016. This is followed by a summary of FEI's proposed revenue requirement and rate changes

[1] PBR Decision, p. 138.
[2] This amount is pre-tax and includes both the estimated 2016 earnings sharing and adjustments related to 2015 actuals.
[3] Based on a Mainland residential customer using approximately 90 GJs per year, exclusive of delivery rate riders.
[4] Conference Board of Canada - Provincial Outlook 2016 - Medium-Term Economic Forecast. (CPI Updated May 11, 2016).

for 2017 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

1.2 APPROVALS SOUGHT

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

1. Delivery rates for all non-bypass customers effective January 1, 2017, resulting in an increase of 1.2 per cent compared to 2016 delivery rates, with the increase to be applied to the delivery charge, holding the 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 All-Inclusive Code of Conduct/Transfer Pricing Policy regulatory proceeding with a one year amortization period, commencing in 2017.
   - A three year amortization period for the existing 2016 Cost of Capital Application deferral account, commencing in 2017.
   - A five year amortization period for the existing Emissions Regulations deferral account, commencing in 2017.
   - Discontinuance of the non-rate base deferral account for the Kingsvale-Oliver Reinforcement Project Feasibility Costs.
3. Rate Stabilization Deferral Account (RSDA) riders for 2017 in the amounts set out in Table 10-7 in Section 10;
4. Phase-In Rate riders for 2017 in the amounts set out in Table 10-9 for Mainland customers and Table 10-11 for Vancouver Island and Whistler customers in Section 10; and
5. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2017 in the amounts set out in Table 10-12 in Section 10.

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
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
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.	FEI has not identified any exogenous factors
5	Review of the Companies' performance with respect to SQI's. 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

Item	Description	Response or Reference
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 was not exceeded for 2015 but the two year cumulative dead band is forecast to be exceeded for 2016. See section 1.4.4.

1.4 *EVALUATION OF THE PBR PLAN*

FEI has continued its productivity focus in 2016 and initiated one additional project 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 realize savings in O&M expenditures. FEI's capital expenditures continue to be above the capital formula amount. Overall, the savings achieved result in $5.115 million of earnings sharing that will be returned to customers in 2017, 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 these savings while maintaining a high level of service quality.

1.4.1 Overview of O&M Savings

In 2016, FEI is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $11.1 million lower than the formula amount, an increase of $0.9 million from that achieved in 2015.

The 2016 projected O&M savings have been achieved with the Company's continued broad-based focus on productivity. Major initiatives involving processes that may span across departments are described in Section 1.4.3 below and comprise a significant portion of the productivity savings, accounting for approximately $5.0 million of the projected O&M savings. Much of the remainder of the projected O&M savings is being achieved through the Company's ongoing productivity focus. Resources are being redeployed and roles and responsibilities are being broadened. Departments and employees are asked to review the way they operate to streamline processes and make it more efficient for our customers to do business with us. Expenditures and filling of vacancies are being reviewed. While some of the savings are one-time in nature (e.g. delay in filling vacancies) as the result of the continuing productivity focus throughout the Company, many of these efficiencies and savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

1.4.2 Staffing Levels

As a result of the Company's focus on productivity and the resulting impact on the Company's labour requirements, staffing levels have declined in recent years but are expected to stabilize and increase somewhat in the remainder of 2016. The projected increase in headcount of 65 from the end of 2015 to the end of 2016 is comprised of new positions and the filling of existing vacancies, primarily from the following areas: 7 headcount for the start-up of the Tilbury LNG Expansion Facility[5]; 6 headcount in Engineering for capital work;6 headcount in EH&S in support of the Target Zero safety program; 16 headcount in the Contact Centre staffing to fill vacancies and to handle higher call volumes expected in the winter season; and the remainder consisting mostly of vacancies filled across other departments.

Table 1-2: 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 Projected	1,721	1,613

As shown in Table 1-2 above, from 2013 Actual to 2016 Projected, total FTEs for the Company decreased by 66, with the decreases estimated to contribute to O&M savings of approximately $5 million[7].

To-date, the largest FTE declines have been in the Customer Service and Operations areas. Customer Service reductions have resulted from a management reorganization and reductions in staffing related to experienced lower call volumes and lower high-bill complaints as the result of warmer weather in recent years. Included in the Customer Service reductions are positions related to Project Blue Pencil that occurred in 2015. Operations reductions have been realized as the result of ongoing productivity initiatives. Included in the Operations reductions are FTE reductions related to the Regionalization Initiative. Phase 1 of the Regionalization initiative started in 2014 and Phase 2 in 2016.

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:

5 The O&M and capital costs for the Tilbury Expansion are flowed through outside of the PBR formula.

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.

7 2013 Actual FTEs is used as the reference point for the start of the PBR Plan as a 2014 Base average FTEs is not available. The O&M savings are calculated by comparing the 2013 actual average FTEs to the 2016 projected average FTEs.

> 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 2016. A table for each initiative that has been implemented (initiatives 1 through 3 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. The first full year operating under a regional business model was 2015. Annual O&M savings in 2015 were approximately $0.9 million compared to 2013 actuals. The second phase of the Regionalization Initiative is expected to result in incremental annual O&M savings of approximately $1.1 million.

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, those operational savings have been sustained at approximately $1 million.

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 responsible for providing Information Systems (IS) Customer and Infrastructure Services to FEI. 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. The 2015 O&M savings for the Information Systems department compared to 2013 actuals are approximately $1.8 million. For 2016, the Company is continuing to work with Compugen to identify efficiencies.

4. ***The Training and Development Initiative*** was implemented in 2015 and introduced a company-wide process that improves the ability of the Company to plan and track required training activities, ensuring skills requirements for employee training are addressed efficiently and effectively. All departments are now able to evaluate more effectively the training requirements specific to their group. Further work is being undertaken in 2016 to refine training and competency requirements for individual roles. There are no O&M savings anticipated.

5. ***Online Service Application*** is an initiative to enhance service to customers. FEI is currently working on the development of an online service application for installation of new service lines. The Online Service Application initiative 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. The Online Service Application is in the final stages of development with an anticipated phased launch approach, with the first phase of the launch being a release to a select group of builder/developers for field trials early in the third quarter of 2016 and a broad launch in the fall of 2016, in line with the peak building season. Customers will be able to determine if gas service is available in their area and the cost to install the service and will be able to schedule the service online. For builders and developers as well as contractors, the online tool also offers additional capabilities to manage and track multiple service applications.

Details of other future initiatives will be provided in upcoming annual reviews as they reach implementation stage.

1.4.4 Overview of Capital Expenditures

FEI is projecting that capital expenditures will be above the formula in 2016.

1.4.4.1 Capital Spending Results

FEI's capital spending has been consistently above the formula amount in each year of the PBR term to date, and this trend is expected to continue. Table 1-3 below shows the capital spending from 2014 to 2016.

Table 1-3: Capital Expenditures 2014 to 2016 ($ millions)

	2014			2015			2016			Cumulative		
	Actual	Formula	Variance	Actual	Formula	Variance	Projected	Formula	Variance	Projected	Formula	Variance
Growth	24.231	21.478	2.753	45.776	28.480	17.296	41.195	33.262	7.933	111.202	83.220	27.982
Other	100.168	98.343	1.825	107.803	110.901	- 3.098	117.887	112.053	5.834	325.858	321.297	4.561
Pension/OPEB	3.915	3.915	-	4.324	4.324	-	4.075	4.075	-	12.314	12.314	-
Total	128.314	123.736	4.578	157.903	143.705	14.198	163.157	149.390	13.767	449.374	416.831	32.543
			3.70%			*9.88%*			*9.22%*			*7.81%*

As shown in Table 1-3, Projected 2016 capital expenditures excluding items forecast outside of the PBR formula are $13.767 million higher than the formula amount. There are a number of contributing factors which are discussed below.

A contributing set of 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[8], resulting in an impact of $6.4 million in 2016 and $12.8 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,[9] resulting in an impact of $3.8 million in 2016 and $3.0 million cumulative[10]; and
3. The X factor was increased by 0.6percent (from 0.5percent to 1.1percent), resulting in an impact of $0.9 million in 2016 and $2.4 million cumulative.

Another contributing set of factors consists of capital cost pressures such as the following:

1. The addition of certain larger industrial mains where the cost significantly exceeded the average customer addition cost that was contemplated under the formula, but that had incremental revenues attached to them and therefore passed the main extension test;
2. Capital costs required to carry out the Regionalization Initiative discussed above;
3. The installation of Jomar valves on meter sets to allow for meters to be exchanged without turning off gas to the residence;
4. Increased in-line inspection activity required to maintain alignment with evolving industry practice;

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8 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.

9 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.

10 The capital growth factor was negative in both 2014 and 2015 as compared to the prior year, and positive in 2016; therefore the cumulative impact is less than the 2016 impact.

5. Unanticipated system improvements and new stations to supply gas to large new customers;
6. Integrity related capital for Burns Bog pipeline stress relief; and
7. Pressures from the increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate.

FEI has sought to mitigate the impact of the above factors through a combination of seeking out efficiencies in capital spending and re-prioritizing projects for further evaluation. Examples of efficiency initiatives undertaken to date include Project Blue Pencil, negotiating rates with contractors, better coordination with municipal and Ministry of Transportation projects, reuse of standardized bypass equipment, in-line inspection run coordination, and the in-sourcing of application and infrastructure development. For 2016, FEI is continuing this ongoing productivity focus through pursuing capital efficiencies associated with a number of projects, such as a change in process for the replacement of aging residential regulators, coordination with municipalities during mains renewals and updates to station design requirements.

The re-prioritization process was described in FEI's annual review for 2016 rates. FEI's ability to re-prioritize capital spending, however, is limited and cannot be used to fully mitigate cost pressures. Specifically, further re-prioritization of significant portions of capital work to future years is not recommended as over time it will:

- Result in increasing risk exposure in the system;
- Result in projects being spread across multiple years that could otherwise be combined and completed for a lower total cost;
- Lead to more equipment replacements done on an urgent basis and at a higher cost than a planned replacement; and
- Limit the kind of capital investments required to realize productivity efficiencies and operational savings such as those identified in Section 1.4.3.

FEI has managed its capital spending within the 10 percent capital dead band so far, although the timing of customer growth (due to the lag in when the formula is adjusted) can lead to additional pressures in years like 2015 and 2016 when growth is particularly strong. However, the two-year cumulative 15 percent dead band imposes, in effect, an alternating 10 percent, 5 percent, 10 percent dead band on the Company. In those years when, in effect, only a 5 percent dead band is allowed (such as 2016), managing capital spending within the dead band becomes particularly challenging, especially with the existence of the capital pressures described above.

FEI has carefully reviewed the dead band that was initially approved by the Commission and also the further guidance the Commission has provided on the functioning of the dead band, and provides the following regulatory history.

1.4.4.2 Capital Dead Band Regulatory History

In the PBR Application[11], FEI proposed a capital dead band, and described it as follows:

> FEI has proposed a capital expenditure deadband outside of which rebasing would occur during the PBR term. That is, if total regular capital expenditures vary by more than 10 percent above or below the total formula-based capital expenditures in any year, 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 10 percent deadband from the formula-based amount. This will limit the impact of any capital savings during the PBR Period that would be shared between the customer and Company, and limit the amount of rebasing that would occur after the PBR Period.

Further, in response to an information request[12], FEI provided the following example of the functioning of the dead band:

> Question:
>
> Regarding page 3, lines 19-34, provide a numerical example to show how this capital expenditure deadband would work.
>
> Response:
>
> The total capital spending under PBR for 2014 of $129.031 million, as set out in Exhibit B-1, Figure B6-3 on page 66 is used for illustrative purposes. It is also assumed for ease of illustration that no cost driver adjustments for actual customer count and service line installations are required.
>
> If actual capital spending is below 90 percent of $129.031 million (i.e. $116.128 million) the adjustment described on page 3 of Appendix D4 in this Application would be applied.
>
> Assume for this example that actual capital spending is at 85 percent of the capital spending level under PBR, or $109.676 million.
>
> The difference between 90 percent and 85 percent ($116.128 million - $109.676 million = $6.452 million) is deducted from the formula-based capital expenditures spending level to establish an adjusted formula spending allowance for 2014 that will be incorporated in the rate base to establish revenue requirement calculations for future years; that is, the opening rate base for the following year will reflect the lower amount. The calculation of the formula-allowed capital spending amount for rate calculations in future years is unaffected by this adjustment.
>
> The adjustment of $6.452 million would be deducted from the capital accounts (for ratemaking) in the same proportions as included in the $129.031 million before the adjustment.

[11] PBR Application, Appendix D4.
[12] PBR Proceeding, response to BCUC IR 1.45.1.

In the PBR Decision, the Commission stated:

> Fortis states that "limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%" (FEI Exhibit B-1, p. 8; FBC Exhibit B-1, p. 40).
>
> To this, BCSPO points out that "the proposed deadband does not take into account the fact that capital is cumulative and that, if there is a consistent under spending of 9.5% per year, this will result in capital expenditures that are 46% lower than one year's capital. As such, in addition to the annual threshold of 10% for capital rebasing, BCPSO submits there should be a cumulative threshold that reflects the cumulative nature of capital." (BCSPO PBR Final Argument, p. 10)
>
> There are two provisions in the PBR mechanism that mitigate the impact of this and thereby protect ratepayers in this eventuality. The first is Fortis' proposed dead-band around the actual capital spend relative to the spending envelope, which would be triggered if the under-spend was of sufficient magnitude and/or duration. **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.**
>
> **Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.**
>
> In making this determination, we are mindful of the concerns of Interveners and are of the view that a two year cumulative dead band is appropriate and considers 15 percent over or underspend an appropriate setting for a two year cumulative dead-band. **Accordingly, the Commission Panel directs, in addition to the one year 10 percent dead-band previously approved, a two year cumulative 15 percent dead-band for all Fortis' formulaic capital spending.**

Finally, in the decision accompanying Order G-120-15 that addressed FEI's Capital Exclusion Criteria under PBR, the Commission stated:[13]

> As noted, the PBR Decisions provided direction on the setting of dead band parameters but provided no definitive direction with respect to the process to deal with rebasing future base capital amounts in the event that the dead band parameters are exceeded. This is addressed below.
>
> The Panel accepts there are a number of reasons why a capital expenditure level may be higher or lower than the threshold. Some of these may support and justify raising or lowering base capital while others may demonstrate a particular result to be an anomaly, not necessarily requiring rebasing. Because of this, the Panel determines that the full

[13] Capital Exclusion Criteria Decision, p. 17.

circumstances of any variance from the dead-band must be examined in a transparent manner at the annual review process. **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 I-X mechanism.** This will provide interveners the opportunity to review and comment on any such proposed changes prior to the Commission making its determination.

1.4.4.3 Treatment of Capital Spending outside of the Dead Band

Based on the regulatory history discussed above, 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.

At this time, for 2016, FEI is projecting to be within the 10 percent one-year capital dead band, but to exceed the 15 percent two-year cumulative dead band. Specifically, over 2015 and 2016, capital spending will be cumulatively 19.1 percent above the combined capital formula amounts for those years, which exceeds the two-year cumulative dead band by 4.1 percent. Accordingly, FEI has added 4.1 percent of its 2016 capital spending, or $6.118 million[14] to its opening plant in service for 2017. FEI has also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($6.118 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.

At this time, FEI is not recommending an increase to the annual capital formula amount for the remaining years of the PBR term. Within the many projects that contribute to capital spending

[14] $163.157 million actual spending less $6.118 million = $157.039 million revised spending. When compared to $149.390 million approved formula this results in a revised capital spending variance of 5.12%. 2015 variance of 9.88% plus 2016 revised variance of 5.12% = 15%.

in any given year, FEI is unable to isolate any that in particular are ongoing and should be added to the formula. FEI does not believe that a lengthy process to review what capital items should be added into the capital formula is an efficient solution to the ongoing capital issues. By not adjusting the capital formula amount, the incentive properties of the PBR Plan remain intact and will remain consistent throughout the remainder of the PBR term. While FEI expects to continue 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.

1.4.4.4 Conclusion on Capital Spending

FEI has evaluated its alternatives and believes that it is in the best long-term interest of customers to pursue the capital spending program it has planned that will result in the dead band being exceeded, not only in 2016, but in some of the remaining years of the PBR term. It is clear that the capital spending is required and it is the right thing to do to limit increasing risk exposure in the system, and avoid unplanned and urgent capital work. It is also required to provide FEI the ability to work in an efficient and cost-effective manner and realize productivity efficiencies and operational savings during the PBR term.

1.4.5 Summary

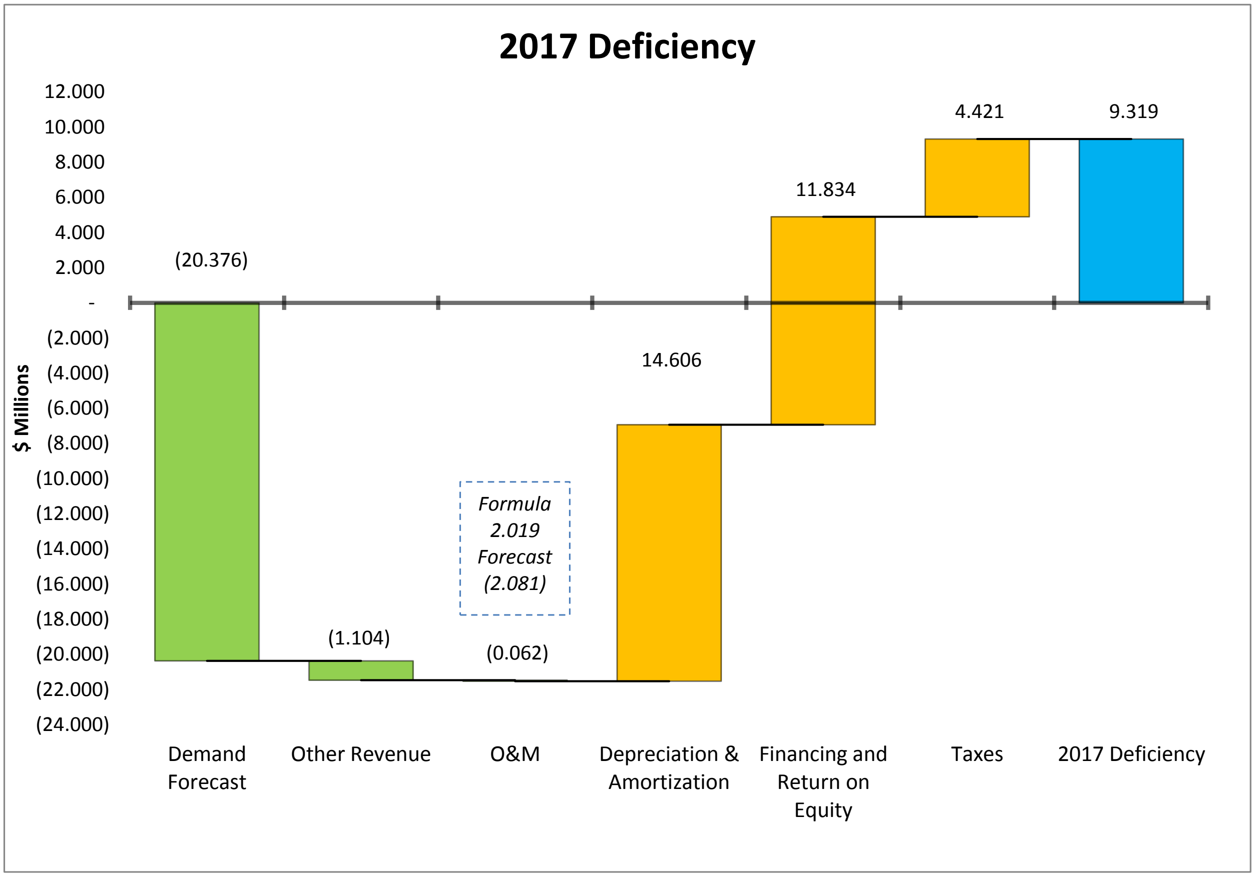
In summary, FEI's experience in 2014 through 2016 has resulted in the realization of earnings sharing on O&M, with increases in delivery rates that are in line with inflation. The first three years of PBR have also shown the challenges of the capital formula that are expected to continue and impact the remainder of the PBR term.

1.5 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2017*

The Company is requesting a delivery rate increase of 1.2 percent for 2017 compared to 2016 delivery rates. The rate increase results from a revenue deficiency of $9.319 million. The revenue deficiency is due to revenue at existing rates being lower than the forecast cost of service. The forecast cost of service is impacted by both items calculated under the PBR Plan formula (controllable O&M and capital expenditures), and items that are forecast on a cost of service basis.

The following chart summarizes the items that contribute to the 2017 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The total deficiency is then the sum of all of the previous bars, and is shown at the end of the chart in blue.

Figure 1-1: 2017 Delivery Revenue Deficiency ($ millions)[15]



Each of the categories is discussed briefly below.

1.5.1 Demand Forecast (Section 3)

In 2017, demand is forecast to increase, by 8.0 PJs from 2016 approved, with the main increases being 2.0 PJs for Rate Schedule 22 demand, 1.8 PJs for residential demand, 1.6 PJs for Rate Schedule 46, 1.5 PJs in additional BC Hydro Island Cogeneration Project contract demand and 1.2 PJs in additional commercial customer demand. Based on the existing rates for each rate schedule, FEI's 2017 revenue forecast at existing rates is $1,088.812 million and 2017 gross margin forecast is $789.518 million.

1.5.2 Other Revenue (Section 5)

Other revenue is forecast to decrease the 2017 deficiency by approximately $1.104 million, almost all due to additional Natural Gas for Transportation (NGT) related recoveries.

[15] Due to its relative size, the impact of increasing formula capital of approximately $0.057 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 2017, the formula incorporates an inflation factor (I Factor) of 1.399 percent, a productivity improvement factor (X Factor) of 1.1 percent and a customer growth factor of 0.675 percent for a total increase in formula O&M of 0.964 percent. O&M forecast outside of the formula is decreasing at a rate of 7.204 percent, primarily due to decreases in pension and OPEB offset by higher O&M supporting incremental revenues from Rate Schedule 46 (Liquefied Natural Gas Sales, Dispensing and Transportation Service). Overall the decrease in Gross O&M Expense from 2016 to 2017 is 0.045 percent. The decrease in O&M expense net of capitalized overhead is $0.062 million.

1.5.4 Depreciation and Amortization (Section 7 and Section 12)

The increase in depreciation expense is the result of increases from higher plant in service, mainly due to the Tilbury Expansion Project, being offset by lower depreciation rates as approved by an updated depreciation study. There has also been an increase in amortization expense of $4.488 million. This is due to a number of factors, including an increase of $13.0 million resulting from updated net salvage and contribution in aid of construction (CIAC) amortization rates from the depreciation study, a higher balance in the Energy Efficiency and Conservation and NGT Incentives deferrals and the reduced amortization in the Property Tax deferral. These are offset by the reduced amortization of the Pension and OPEB Variance deferral and the increased credit amortization of the Flow Through Variance Account.

1.5.5 Financing and Return on Equity (Section 8)

FEI has not forecast any long-term debt issues for 2017. FEI is forecasting a short-term debt rate for 2017 of 1.40 percent, an increase from the 1.25 percent rate embedded in the 2016 forecast. Overall, interest expense is forecast to decrease from 2016 by $3.258 million primarily due to the retirement of debt with a coupon rate of 10.3 percent in late 2016 and the replacement debt issued at a significantly lower rate.

Increases in rate base increase the equity return by $15.092 million. Pending a decision on FEI's return on equity and capital structure, FEI has utilized its interim approved 2016 capital structure and return on equity of 38.5 percent at 8.75 percent, respectively which will be updated when a decision is received.

1.5.6 Taxes (Section 9)

Property taxes are forecast to increase 7.0 percent or $4.414 million from 2016. Increases are driven by construction activities, market value increases and changes in tax policies of local taxing authorities.

There has been no change in the income tax rate of 26 percent from 2016. Taxes are forecast to increase in 2017 by $0.007 million primarily due to a higher delivery margin in 2017 offset by an increase in capital cost allowance deductions in 2017.

1.6 SERVICE QUALITY INDICATORS

FEI's 2015 and June 2016 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2015, for those SQIs with benchmarks, seven performed better than the approved benchmarks with the remaining two performing better than the threshold and within the performance range. In 2016 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 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 2017 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:

1. FortisBC Energy Inc. is approved to use inflation data from July through June for the 2014 rate change calculations and the future annual reviews.
2. FortisBC Energy Inc. is approved to use 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 2017. FEI has used July 2014 through June 2016 inflation data for the 2017 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

As discussed below, the 2017 inflation factor based on prior year's BC-CPI and BC-AWE is 1.399 percent, and the SLA and AC Growth Factors are 0.324 percent and 0.675 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 2016 has been used as a placeholder for June 2016 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 1.627 percent and AWE-BC of 1.212 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (1.627 percent x 45 percent) + (1.212 percent x 55 percent) = 1.399 percent.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020	*CANSIM 281-0063*	12 Mth Average		Year over year % change			
	2002 = 100							
	BC CPI	BC AWE	CPI	AWE	CPI	AWE	I Factor	PBR Year
Date	index	$	index	$	%	%	%	
Jul-2014	119.6	892.69						
Aug-2014	119.6	902.67						
Sep-2014	119.5	898.29						
Oct-2014	119.0	904.76						
Nov-2014	118.8	906.17						
Dec-2014	118.1	895.32						
Jan-2015	118.0	911.03						
Feb-2015	118.9	909.02						
Mar-2015	119.8	905.21						
Apr-2015	119.6	903.26						
May-2015	120.6	905.28						
Jun-2015	120.7	909.59	119.350	903.608				
Jul-2015	120.8	913.87						
Aug-2015	121.0	906.46						
Sep-2015	121.0	911.95						
Oct-2015	120.6	913.09						
Nov-2015	120.8	910.40						
Dec-2015	120.4	925.59						
Jan-2016	120.7	905.14						
Feb-2016	120.8	913.43						
Mar-2016	121.8	915.72						
Apr-2016	121.8	920.79						
May-2016	122.7	919.11						
Jun-2016	123.1	919.11	121.292	914.56	1.627%	1.212%	1.399%	2017

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 $[1 + ((AC_{t-1}-AC_{t-2})/ AC_{t-2}) \times 50\%)]$.

The calculations for the Average Customer and Service Line Additions growth factors are provided in Tables 2-2 and 2-3 below. The AC and SLA growth shown below reflect the amalgamated company, incorporating data for Vancouver Island and Whistler service areas for the periods prior to January 2015.

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

	FEI	FEVI	FEW	Total Average Customers	12 Month Avg Customers	AC Factor @ 50%	PBR Year
Jul-14	850,036	104,889	2,721	957,646			
Aug-14	849,603	105,047	2,726	957,376			
Sep-14	849,829	105,323	2,738	957,890			
Oct-14	851,467	105,719	2,755	959,941			
Nov-14	854,127	106,227	2,762	963,116			
Dec-14	855,614	106,629	2,768	965,011			
Jan-15	966,744			966,744			
Feb-15	967,096			967,096			
Mar-15	967,144			967,144			
Apr-15	967,038			967,038			
May-15	966,516			966,516			
Jun-15	965,884			965,884	963,450		
Jul-15	965,397			965,397			
Aug-15	965,359			965,359			
Sep-15	967,699			967,699			
Oct-15	971,075			971,075			
Nov-15	975,988			975,988			
Dec-15	979,243			979,243			
Jan-16	981,191			981,191			
Feb-16	981,838			981,838			
Mar-16	982,599			982,599			
Apr-16	982,618			982,618			
May-16	982,208			982,208			
Jun-16	982,322			982,322	976,461	0.675%	2017

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

	FEI	FEVI	FEW	Total Service Line Additions	12 Month Sum	SLA Factor @ 50%	PBR Year
Jul-14	668	184	10	862			
Aug-14	706	203	3	912			
Sep-14	972	321	6	1,299			
Oct-14	855	261	7	1,123			
Nov-14	1,363	296	6	1,665			
Dec-14	597	250	3	850			
Jan-15	717	316	2	1,035			
Feb-15	604	256	-	860			
Mar-15	572	214	3	789			
Apr-15	684	222	1	907			
May-15	604	204	9	817			
Jun-15	682	237	6	925	12,044		
Jul-15	795	229	-	1,024			
Aug-15	479	206	-	685			
Sep-15	1,143	372	6	1,521			
Oct-15	983	332	12	1,327			
Nov-15	1,006	369	22	1,397			
Dec-15	864	254	9	1,127			
Jan-16	559	272	5	836			
Feb-16	479	227	1	707			
Mar-16	406	109	2	517			
Apr-16	726	268	-	994			
May-16	733	402	9	1,144			
Jun-16	517	326	-	843	12,122	0.324%	2017

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 2017 is provided in Table 2-4.

Table 2-4: Summary of Formula Drivers

	2017
Cost Drivers	
Service Line Additions Factor @ 50%	0.324%
Customer Growth Factor @ 50%	0.675%
Escalators	
CPI	1.627%
AWE	1.212%
Non Labour	45%
Labour	55%
CPI/AWE Inflation	1.399%
Productivity Factor	-1.100%
Net Inflation Factor	0.299%

In summary, the formula factor for O&M and for sustainment and other capital for 2017 is 100.976 percent, calculated as (1 + 0.675 percent) X (1 + 0.299 percent).

The formula factor for growth capital for 2017 is 100.624 percent, or (1 + 0.324 percent) x (1 + 0.299 percent). This calculation is based on growth in service line additions of 0.324 percent, with the cost per service line addition growing at a rate of 0.299 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 2017, as well as the revenue and margin at 2016 common delivery rates and applicable 2016 commodity, storage and transport rates[16]. As described in detail below, FEI's forecast of demand for natural gas is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand for 2017. FEI is forecasting an increase in consumption in 2017 compared to both the new 2016 projected demand and the 2016 Approved demand. The total normalized demand is forecast to be approximately 215.8 PJs in 2017, up approximately 3.7 PJs compared to the new 2016 projected demand. Of the 3.7 PJ increase, approximately half is from higher industrial volumes and half is from increased LNG volumes. Compared to the 2016 Approved demand of 207.6 PJs[17], the 215.8 PJs forecast for 2017 is up approximately 8.2 PJs with the main increases being 2.0 PJs for Rate Schedule 22 demand, 1.8 PJs for residential demand, 1.6 PJs for Rate Schedule 46, 1.5 PJs in additional BC Hydro Island Cogeneration Project contract demand and 1.2 PJs in additional commercial customer demand. Based on the 2016 rates for each customer class, FEI's 2017 revenue forecast at existing rates is $1,088.812 million and FEI's 2017 gross margin forecast is $789.518 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 Addition 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

[16] Orders G-193-for delivery rates, G-188-15 for storage and transport rates and the commodity rate effective January 1, 2016 and G-37-16 for the gas commodity rate and G-33-16 for the propane commodity rate effective April 1, 2016. The delivery rates do not include delivery rate riders which are set separately from the delivery rate.

[17] Excludes Burrard Thermal demand of 0.2 PJs.

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

  Provides historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals, including variance analysis and the results of the Industrial Survey. FEI's demand forecast method has performed well. Based on the 10 years of data shown in section 3.5 of Appendix A2, the 10-year mean average percentage error of the aggregate demand forecast is 2.7 percent, which includes a residential demand forecast error of 2.1 percent and a commercial demand forecast error of 2.0 percent. Most recently, the aggregate demand forecast error for 2015 was 2.1 percent which includes a residential demand forecast error of 1.3 percent and a commercial demand forecast error of 0.3 percent.

- Appendix A3 – Demand Forecast Methodology

  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.

- Appendix A4 – FEI's Response to the Commission's Forecasting Directives

  Provides an analysis of alternatives to FEI's existing forecast method and FEI's recommendations for residential and commercial UPC forecasts and commercial net customer additions forecasts for the remainder of the PBR term. Based on surveys conducted by ITRON Inc. and Boreas Consulting, FEI's demand forecast method consistently outperformed the average performance of forecasts from other gas utilities of 4 percent. FEI has identified and tested alternative forecast methods and found one that offers the potential to improve on the accuracy of FEI's existing method. FEI will continue testing this alternative over the remainder of the PBR term to determine if it is preferable to the existing method.

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 net customer additions and UPC rates, consistent with the past methodology. Specifically, the

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

average UPC is estimated for customers served under Rate Schedules 1, 2, and 3/23 and is then multiplied by the corresponding forecast of the number of customers (opening number of customers plus average 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 a survey as discussed in Section 3.5.3.

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

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.

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

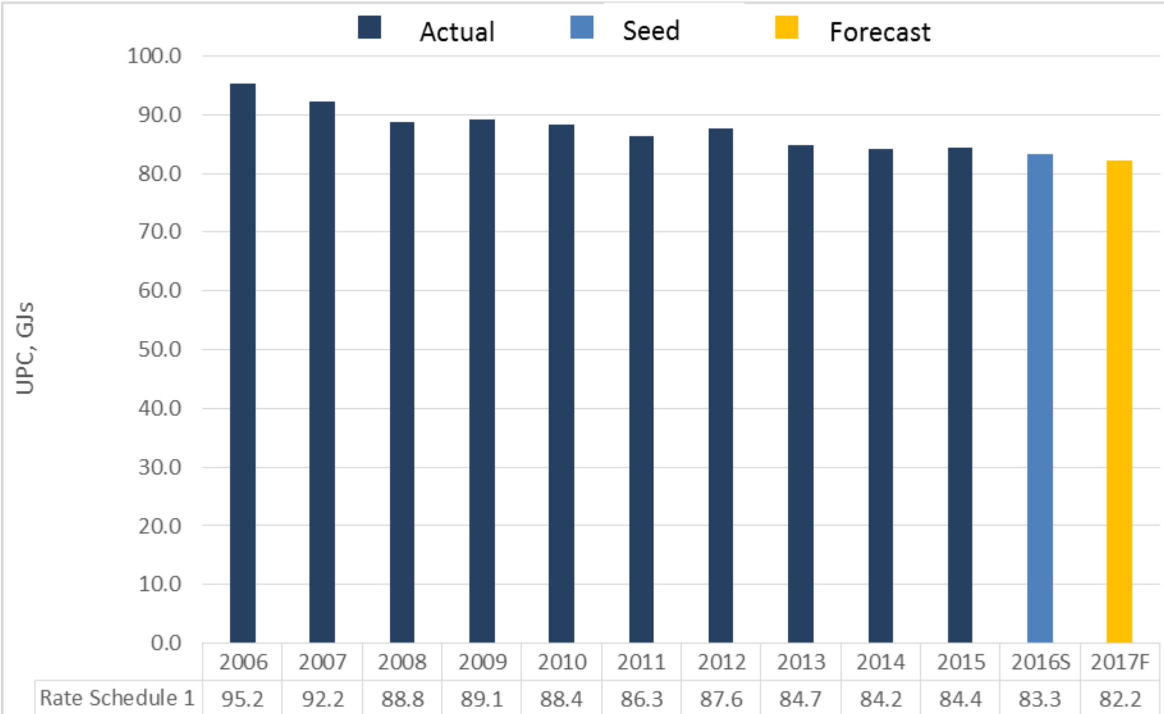
- Actual Years: Actual years are those for which actual data exists for the full calendar year. The 2017 Annual Review is based on actual data up to and including 2015, the latest calendar year for which full actual data exists is the 2015 calendar year.
- Seed Year: The Seed Year is the year prior to 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 2016 and the Seed Year forecast is based on the latest actual years, including 2015. As such, the 2016 Seed Year forecast in this Application will differ from the 2016 Forecast presented in the Annual Review for 2016 Delivery Rates, for which 2015 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 a range of 2 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 a continued downward trend, while normalized commercial use rates are decreasing in 2017 for Rate Schedules 2 and 3, by 0.6 and 1.6 percent respectively, while increasing in 2017 for Rate Schedule 23 by 0.3 percent.

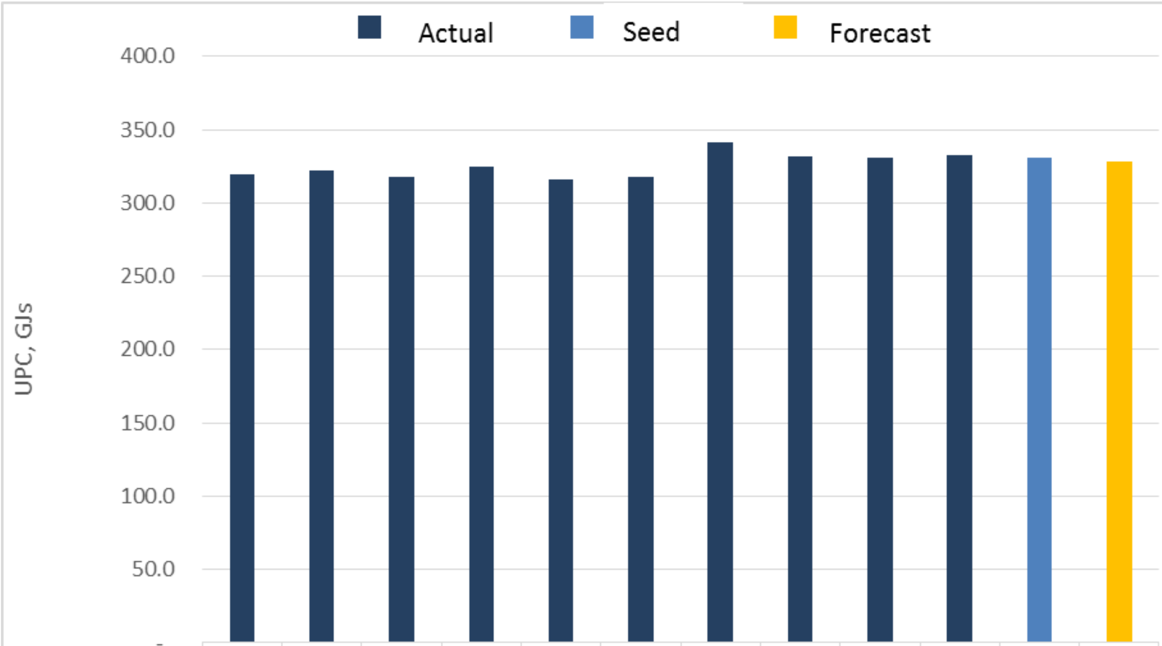
As shown in Figure 3-1, the Residential (Rate Schedule 1) UPC is forecast to decline by approximately 1.1 GJs (1.3 percent) in 2017.

Figure 3-1: Rate Schedule 1 UPC



As shown in Figure 3-2, the Small Commercial (Rate Schedule 2) UPC is forecast to decrease slightly, by 2.1 GJs (0.6 percent), during 2017.

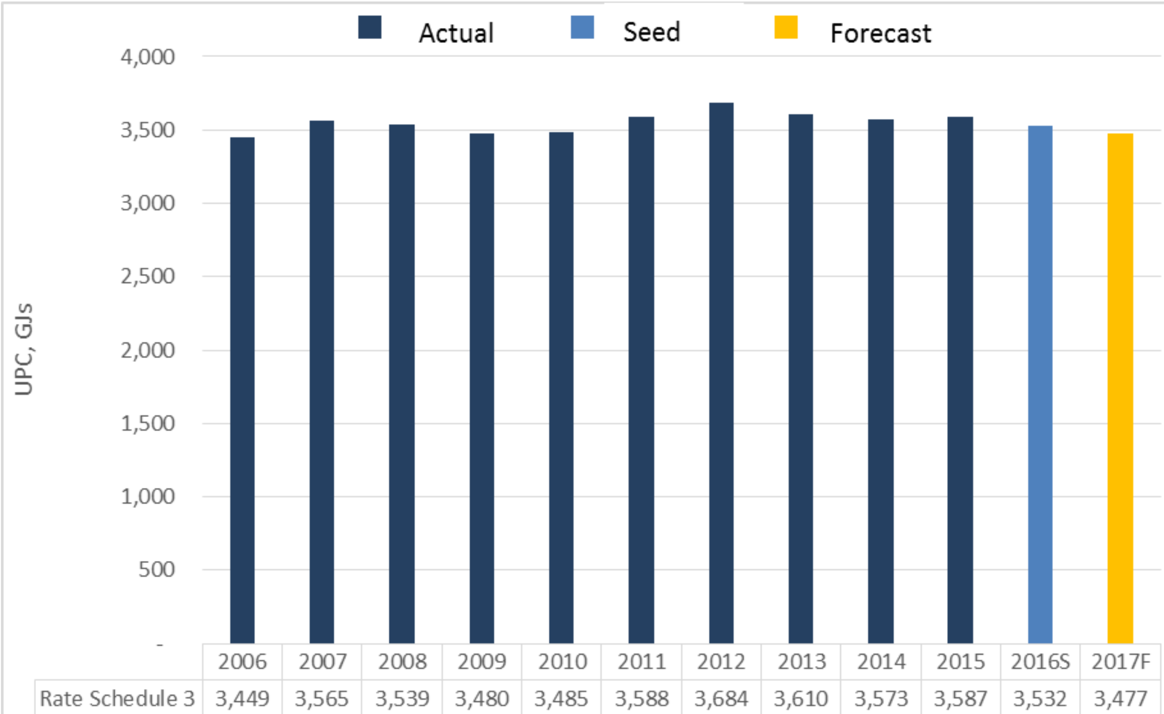
Figure 3-2: Rate Schedule 2 UPC



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Rate Schedule 2	319.3	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	330.5	328.4

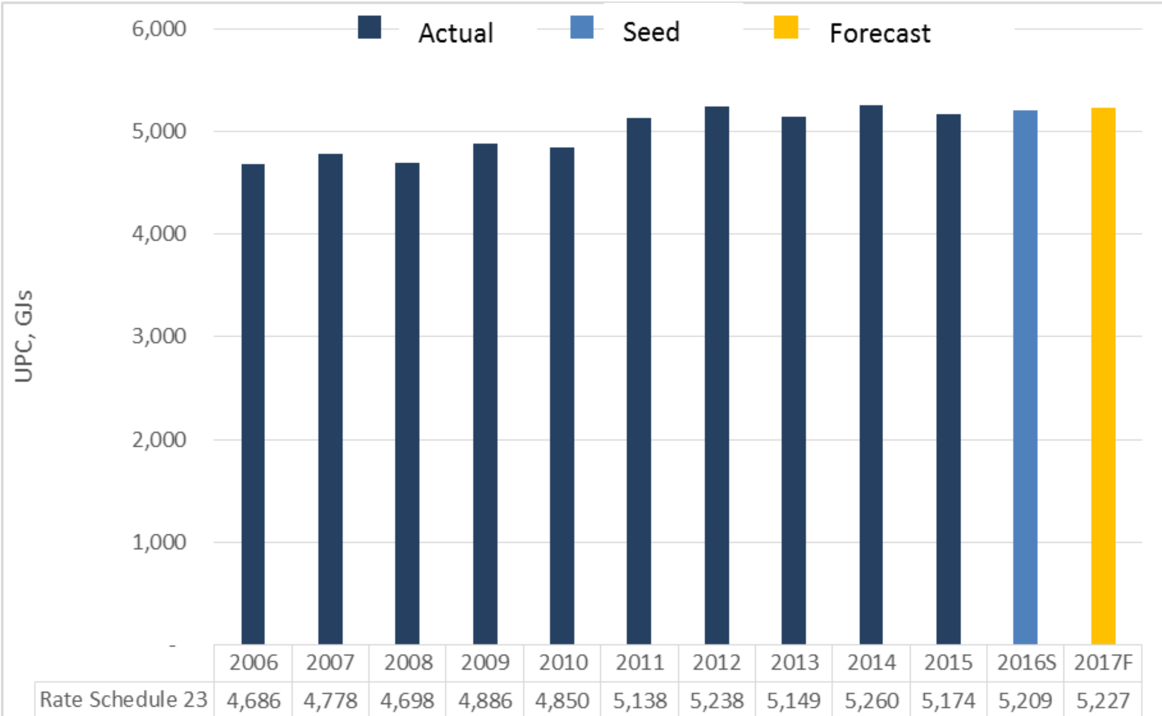
As shown in Figure 3-3, a recent downward trend in Large Commercial (Rate Schedule 3) UPC is forecast to continue. The Rate Schedule 3 UPC is forecast to decrease slightly by 55 GJs (1.6 percent) in 2017.

Figure 3-3: Rate Schedule 3 UPC



As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to continue the recent upward trend and grow by 18 GJs (0.3 percent) in 2017.

Figure 3-4: Rate Schedule 23 UPC

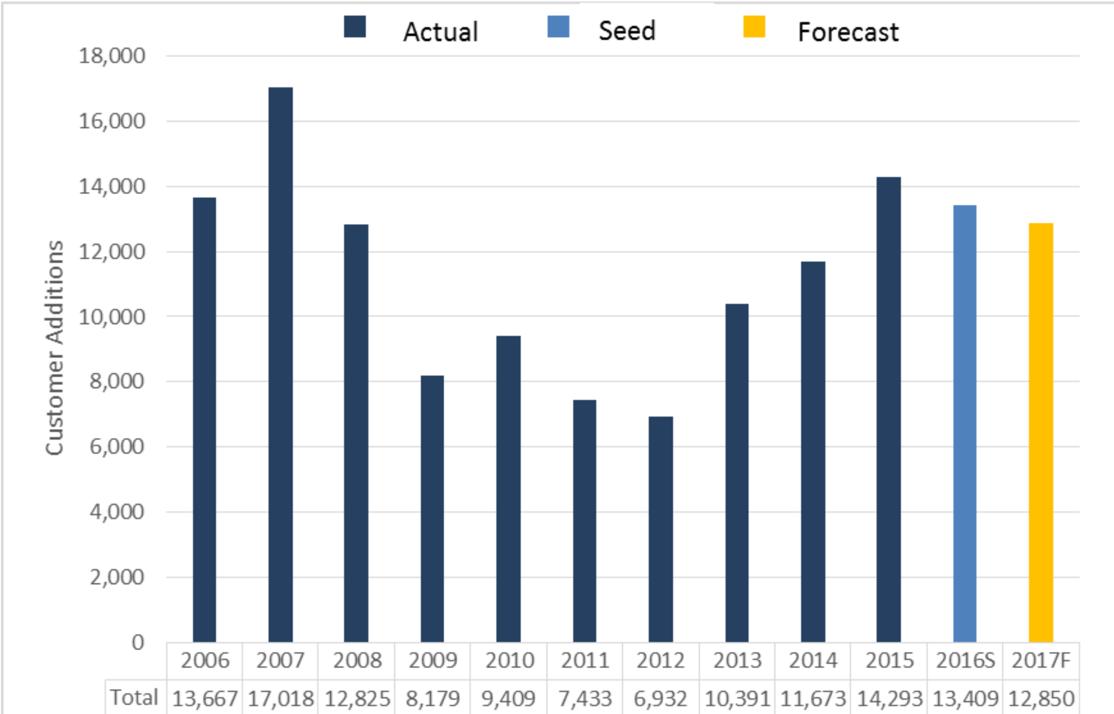


3.4 *RESIDENTIAL AND COMMERCIAL NET CUSTOMER ADDITIONS FORECAST*

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 a high in 2007 of roughly 17,000 net customer additions then declined to below 10,000 annual net customer additions for the period from 2009 through 2012. Net customer additions in 2013 and 2014 were stronger, above 10,000 per year, with an additional large increase in 2015 up to above 14,000 net customer additions. The Company is forecasting customer additions at approximately 13,409 in 2016 and 12,850 in 2017.

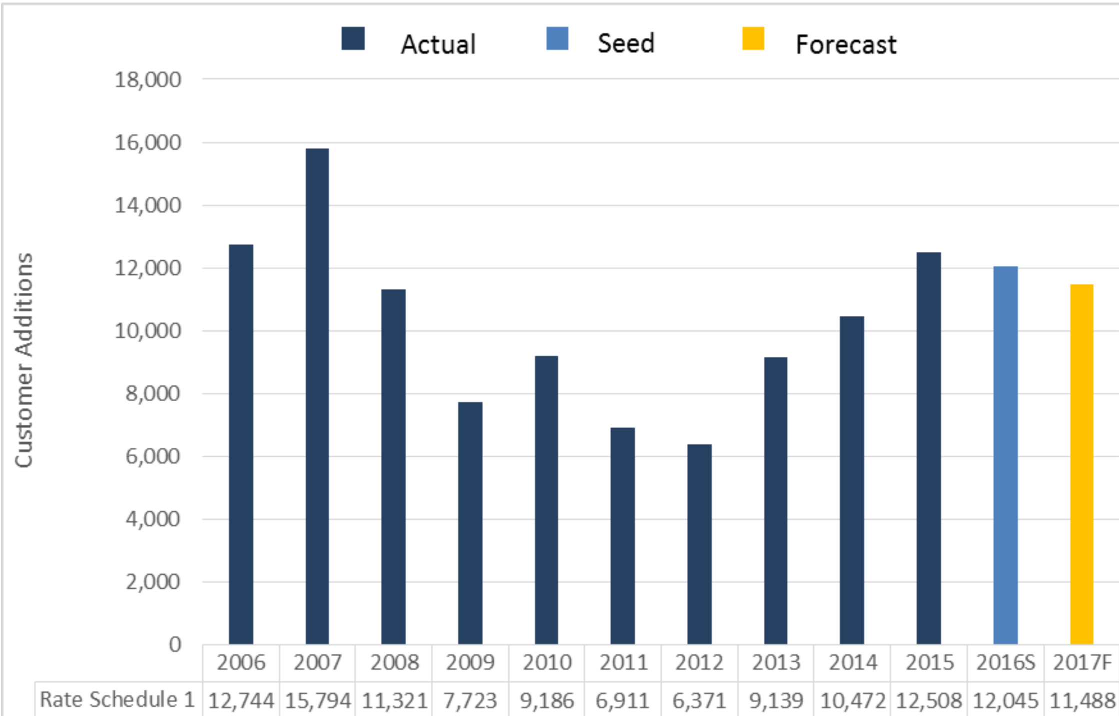
Figure 3-5: Total Net Customer Additions



The Conference Board of Canada (CBOC) housing starts forecast found in Appendix A1 provides a proxy for residential net customer additions, while 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., 2013 to 2015).

Figure 3-6 provides a breakdown of the residential net customer additions for 2017.

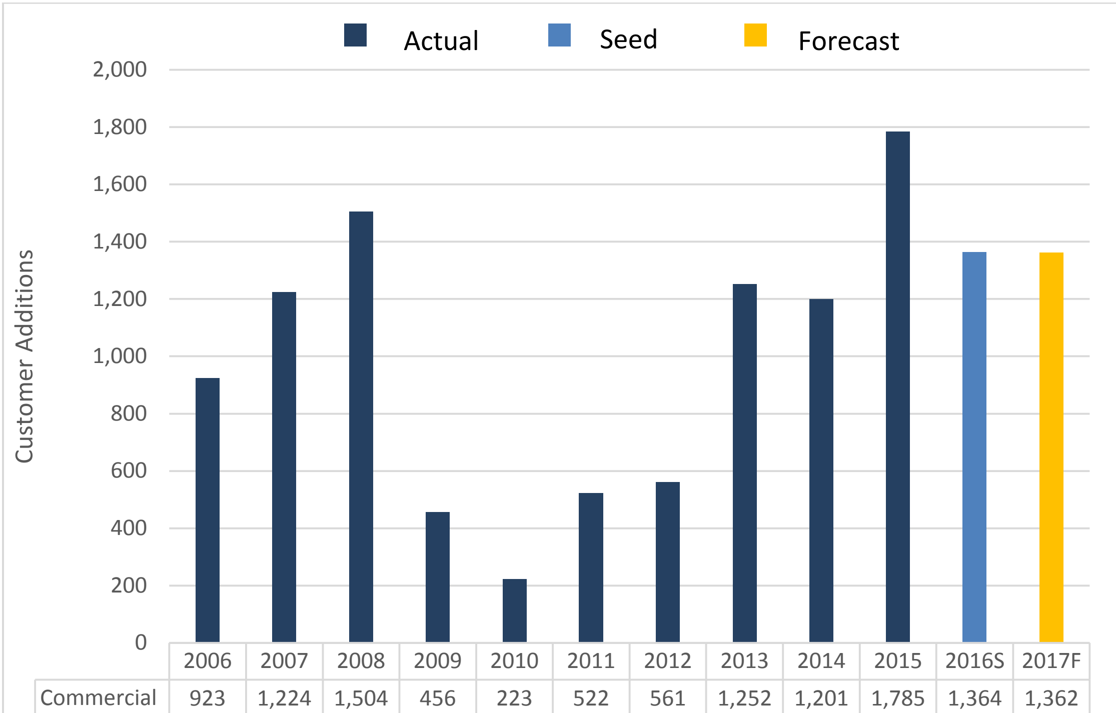
Figure 3-6: Residential Net Customer Additions



As shown in the preceding figure, residential net customer additions started to recover in 2013 and have been fairly consistent in the years since then. The 2016 and 2017 forecast of 12,045 and 11,488, respectively, is consistent with the past two years of actual experience.

Figure 3-7 provides a breakdown of the commercial net customer additions for 2017.

Figure 3-7: Commercial Net Customers Additions

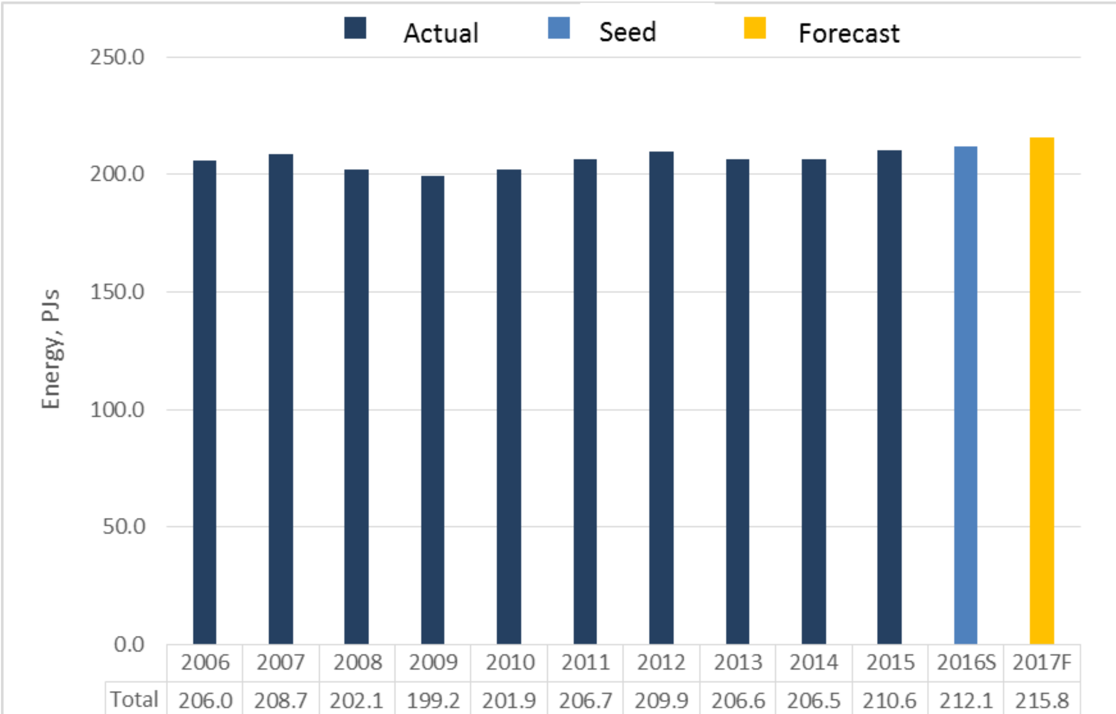


As shown above, the Company is forecasting over 1,300 commercial net customer additions for 2017 based on three years of history (2013 to 2015).

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 215.8 PJs in 2017, up approximately 3.7 PJs from 2016.

Figure 3-8: Total Energy Demand in PJs

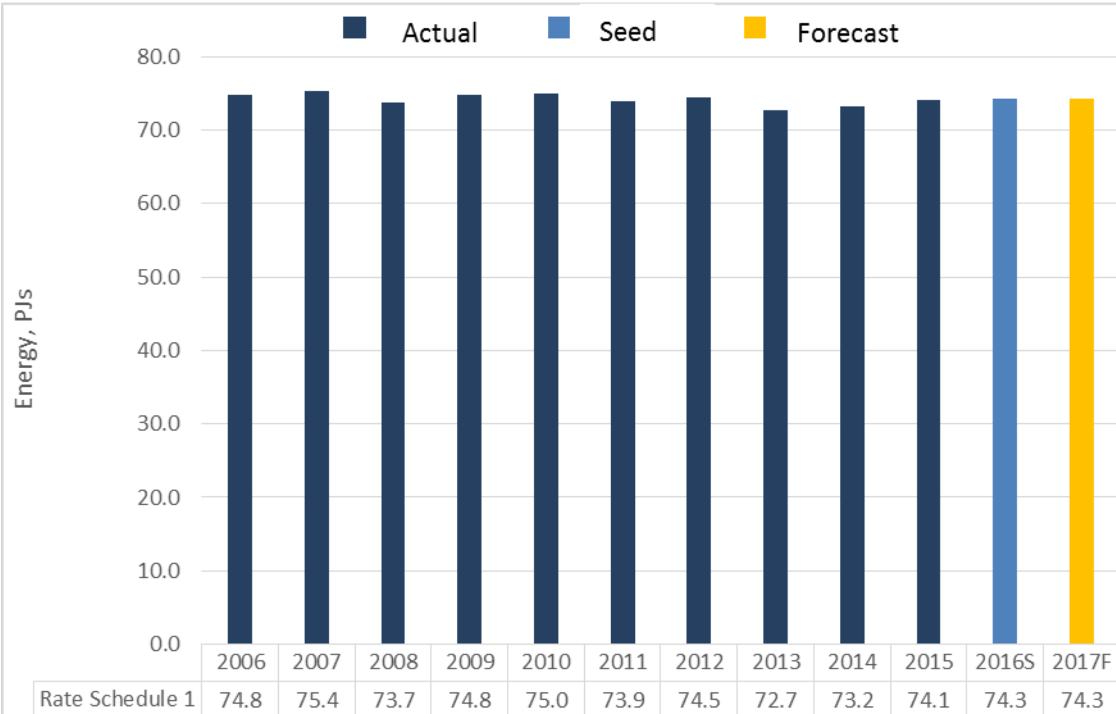


The residential and commercial, industrial and NGT demand forecasts are provided separately in the following subsections.

3.5.1 Residential Demand

As shown below in Figure 3-9, the impact of the forecast 2017 residential net customer additions offsets the forecast decline in average residential UPC, which results in a stable forecast in residential normalized energy demand.

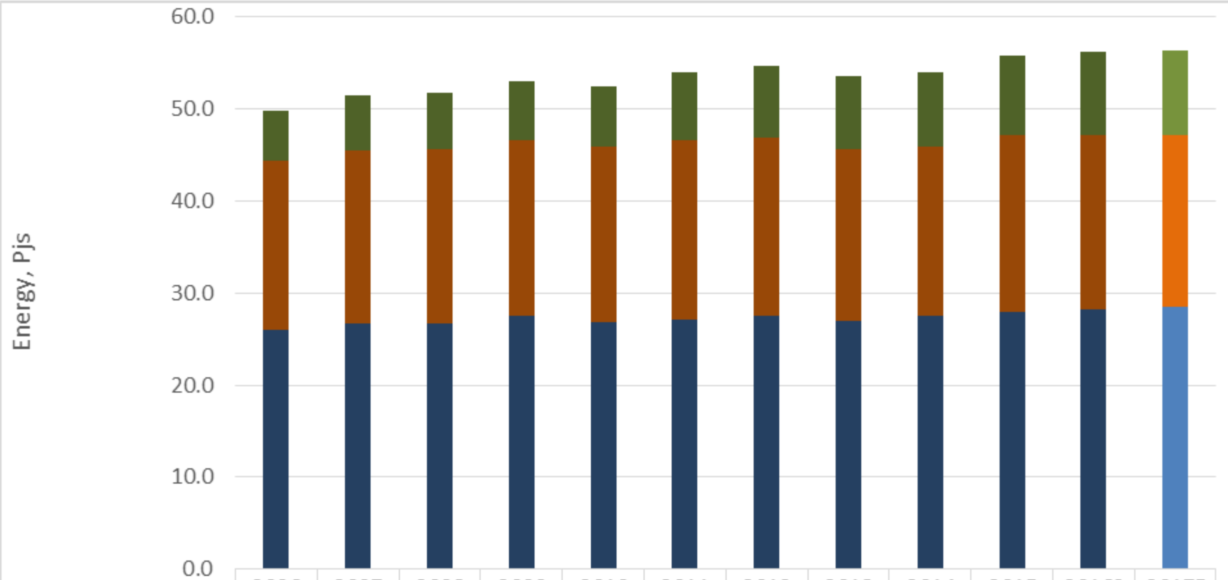
Figure 3-9: Normalized Residential Demand



3.5.2 Commercial Demand

As seen in Figure 3-10 below, demand in Rate Schedules 2 and 23 are forecast to grow slightly in 2017, partially offset by a slight decline in Rate Schedule 3 demand.

Figure 3-10: Commercial Demand



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Rate Schedule 23	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6	9.0	9.2
Rate Schedule 3	18.3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2	18.8	18.6
Rate Schedule 2	26.0	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0	28.3	28.5

3.5.3 Industrial Demand

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

Consistent with past practice, the forecast demand for Vancouver Island Joint Venture and BC Hydro Island Cogeneration Project is set at the contract demand for each customer and these customers are not surveyed.

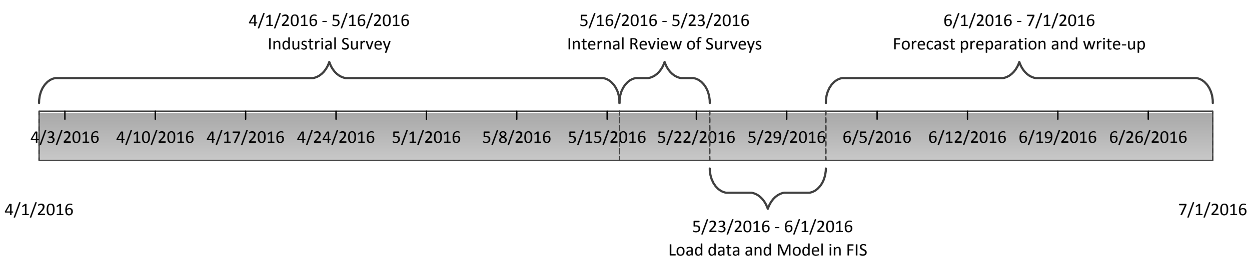
FEI's survey methodology is consistent with prior years and continues to include the improvements to the methodology resulting from FEI's review of its Demand Forecast Methodology for Rate Schedule 22, as reported in Appendix A4 of FEI's Annual Review for 2016 Delivery Rates Application.[19] The two improvements were (1) to shorten the time period between the survey and the test period to reduce the likelihood of fuel switching or business start-up happening between the survey and test period, and (2) to review the survey results for all large volume (Rate Schedule 22 and 27) customers with key account managers. In the past two years, the review process has resulted in several surveys being corrected after communications with the customer.

For the 2017 Forecast, customers completed the survey in April and May 2016. 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 May 15,

[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.

2016 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 six weeks, the latest possible start date for the survey was April 1, 2016. The timeline is shown below:

Figure 3-11: Industrial Survey Timeline



As shown in Table 3-1 below, the response rate achieved in 2016 was 51 percent of industrial customers, representing approximately 89 percent of industrial volumes. Of the remaining industrial customers, 34 percent received the survey and three reminder letters but did not reply. This group represents 9 percent of the industrial demand. Surveys could not be delivered to 15 percent of the industrial customers due to issues such as incorrect email addresses. This group represents just 2 percent of the total industrial load.

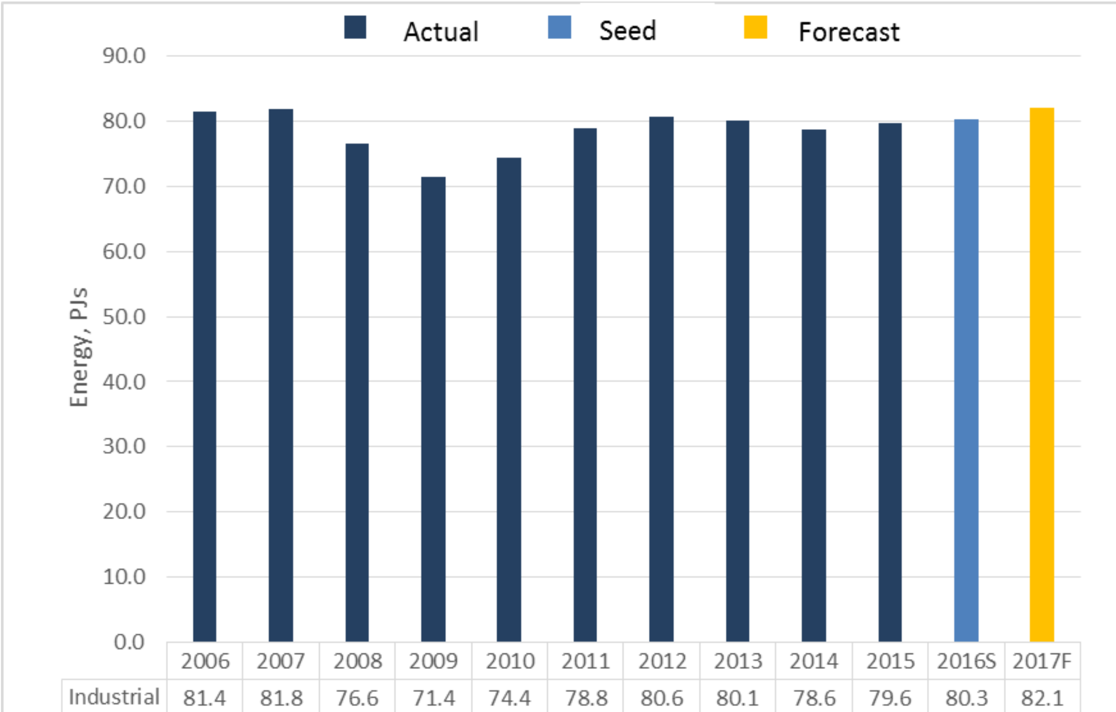
Table 3-1: Industrial Survey Response Rates

2016 Industrial Survey	Description	Customers	Demand
Survey completed	The survey was delivered and completed.	51%	89%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	34%	9%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	15%	2%
Total		100%	100%

The forecast of demand for all customers that either chose not to reply to the survey or could not be contacted (representing 11 percent of the total industrial demand) was set to 2015 actual consumption in preparing the 2017 forecast.

As seen in Figure 3-12 below, the demand from the industrial rate schedules is forecast to increase to 82.1 PJs/yr (an increase of 1.8 PJs from 2016).

Figure 3-12: Industrial Demand[20]



The Industrial demand in the figure above includes demand under Rate Schedule 22. The 2017 forecast Rate Schedule 22 demand is 38.2 PJs, up approximately 0.17 PJs from 2016.

3.5.4 Natural Gas for Transportation and LNG Demand

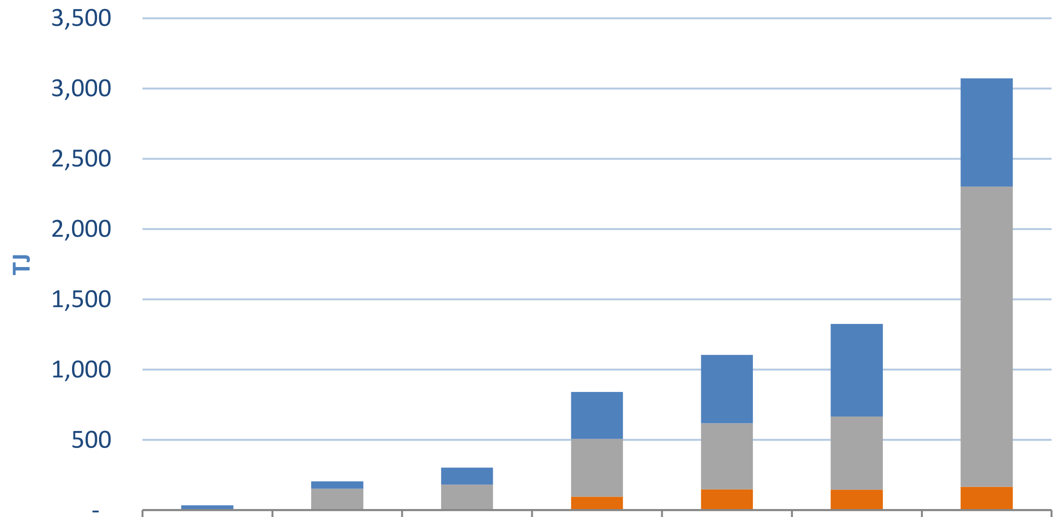
This section summarizes the CNG and LNG demand forecasts related to demand derived from GGRR incentives awarded, FEI's General Terms and Conditions 12B and non-NGT related Rate Schedule 16/46 LNG[21] demand. The details of incentives and fuelling stations driving the NGT portion of this demand can be found in Appendix B.

The following table shows the 2011 to 2015 Actual, 2016 Projected and 2017 Forecast annual demand for CNG and LNG for Rates Schedules 16/46 (LNG) and Rate Schedule 25 (CNG). FEI notes that there was no NGT demand in 2010.

20 Excludes Burrard Thermal and NGT.

21 Rate Schedule 16 expired on December 31, 2014. Actual 2015 volumes, projected 2016 volumes and forecasted 2017 volumes are for Rate Schedule 46.

Figure 3-13: Actual (A) Projected (P) and Forecast (F) Demand for CNG & LNG[22]



	2011A	2012A	2013A	2014A	2015A	2016P	2017F
Rate 25 - NGT	26	52	120	336	486	659	769
Rate16/46 - NGT	8	154	183	411	471	521	2,136
Rate 16/46 - Other	-	-	-	96	147	147	166

The forecast increase in demand in Rate Schedule 25 – CNG is primarily attributable to incremental load from existing customers including Smithrite Disposal Ltd. and Waste Management, as well as new load from Coast Mountain Bus Company and United Parcel Service Canada (UPS). UPS will begin fuelling approximately 47 package courier service vehicles in 2017.

The forecast increase in demand in Rate Schedule 46 – NGT is primarily attributable to new incremental load related to LNG for marine customers such as Puget Sound Energy (PSE)[23], BC Ferries and Seaspan. Of the 1,615 TJs of growth in NGT demand in this rate schedule, 1,546 TJs is related to new incremental load from these customers.

The Rate Schedules 16/46 - Other demand in 2014 to 2017 includes LNG used for non-NGT activities primarily related to the use of LNG for power generation in northern Canada. These customers are currently taking LNG on a spot basis (i.e. with no contract demand). In 2016, FEI expects to deliver approximately 147 TJs to these customers and for 2017 the customers have indicated increases in LNG demand to approximately 166 TJs.

[22] Forecast includes all NGT related and other LNG demand inclusive of contract and excess demand flowing through stations as well as 3rd party station CNG/LNG volume.

[23] FEI has entered into an agreement with PSE to provide LNG to one Shipping vessel that will be operated by Totem Ocean Trailer (TOTE). The Rate Schedule 46 agreement is between FEI and PSE, with PSE providing the LNG to TOTE in the Port of Tacoma. Please refer to Appendix B, Section 4.1 for more information.

3.6 *REVENUE AND MARGIN FORECAST*

The forecast of revenues and margins has been developed by considering the total energy forecast applied at 2016 common delivery rates and applicable 2016 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 common rates for each customer class.

Table 3-2 below summarizes the approved, projected and forecast revenue for 2016 and 2017.

Table 3-2: Forecast Sales Revenue at Approved Rates

Revenue ($ millions)	Approved 2016	Projected 2016	Forecast 2017
Residential[1]	730.278	646.073	634.778
Commercial[2]	394.702	340.212	333.000
Industrial[3]	112.557	103.171	121.034
Total	**1,237.537**	**1,089.456**	**1,088.812**

Notes:
[1] Rate Schedule 1
[2] Rate Schedules 2, 3, 23
[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Burrard Thermal (prior to 2017), Joint Venture, BC Hydro/Island Cogeneration Project

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 2016 and 2017, by customer segment, at 2016 delivery rates.

Table 3-3: Forecast Gross Margin at Approved Rates

Margin ($ millions)	Approved 2016	Projected 2016	Forecast 2017
Residential[1]	442.632	451.555	458.456
Commercial[2]	215.603	219.705	223.564
Industrial[3]	101.588	95.410	107.498
Total	**759.823**	**766.670**	**789.518**

Notes:
[1] Rate Schedule 1
[2] Rate Schedules 2, 3, 23
[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Burrard Thermal (prior to 2017), Joint Venture, BC Hydro/Island Cogeneration Project

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 a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand for 2017. Based on this methodology, FEI is forecasting an increase in consumption in 2017, with the total normalized demand projected to be approximately 216 PJs in 2017, up approximately 3.7 PJs from the new 2016 projected consumption and up approximately 8.2 PJs from the 2016 Approved demand of 207.6 PJs[24]. Based on the 2016 Approved rates for each customer class, FEI's 2017 revenue forecast is $1,088.812 million and 2017 gross margin forecast is $789.518 million.

[24] Excludes Burrard Thermal demand of 0.2 PJs.

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, 2016) 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 April 1, 2016 pursuant to Commission Order G-37-16, dated March 18, 2016. 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, 2016 pursuant to Commission Order G-188-15, dated December 3, 2015.

The propane cost recovery rates for the Revelstoke service area became effective April 1, 2016 pursuant to Commission Order G-33-16, dated March 10, 2016.

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[25]

Cost of Gas ($ millions)	Approved 2016	Projected 2016	Forecast 2017
Residential[1]	287.645	194.518	176.322
Commercial[2]	179.099	120.507	109.436
Industrial[3]	10.970	7.761	13.536
Total	**477.714**	**322.786**	**299.294**

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

[25] 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[26] 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.

[26] 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 2016.

Table 5-1: Other Revenue Components

Other Operating Revenue, ($ millions)			
	Approved 2016	**Projected 2016**	**Forecast 2017**
Late Payment Charge	2.314	2.242	2.178
Connection Charge	3.060	3.082	3.118
Other Recoveries	0.290	0.319	0.319
NGT Related Recoveries	2.898	2.947	4.507
Biomethane Other Revenue	0.294	0.263	0.448
SCP Third Party Revenue	14.957	14.957	14.347
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**41.852**	**41.848**	**42.956**

In the following sections, FEI summarizes the methodology for forecasting 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.[27] 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 2017 forecast.

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

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

Table 5-2: Late Payment Charge Revenue Factor Calculation (revenues in $ millions)[28]

		Actual 2013	Actual 2014	Actual 2015	3 Yr Average
FEI	Late Payment Charge	2.297	2.842	2.545	
FEVI	Late Payment Charge	0.288	0.317		
FEW	Late Payment Charge	0.015	0.014		
		2.600	3.173	2.545	
FEI	Rates 1, 2, 3 Revenue	1,044	1,095	1,062	
FEVI	Rates 1, 2, 3 Revenue	168	153		
FEW	Rates 1, 2, 3 Revenue	11	12		
		1,223	1,260	1,062	
Total	LPC Factor	0.2126%	0.2518%	0.2396%	0.2347%

The Late Payment Charge factor of 0.2347 percent is multiplied by the forecast revenue for Rate Schedules 1 through 3 of $927.978 million to arrive at the forecast Late Payment Charge Revenue of $2.178 million for 2017.

5.2.2 Connection Charge

Consistent with the methodology used in previous years, the Connection Charge revenue is calculated based on three factors: a $25 connection fee, the historical move ratio of 12.5 percent[29] and the projected or forecast number of average customers.

In 2017, 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 2017 forecast amounts in Connection Charge revenue:

> Connection Charge of $25 * (Average Customers of 997,775) * Move Ratio of 12.5% = Connection Charge Revenue of $3.118 million.

5.2.3 Other Recoveries

Other recoveries consist of NSF returned cheque charges as well as other miscellaneous income items. Consistent with past practice, the 2017 forecast of these items has been

[28] The Actual 2013 and 2014 FEI Rates 1, 2, 3 Revenue amounts were incorrectly reported in Table 5-2 in previous Annual Reviews and have been corrected in Table 5-2 of this Application. Any variance between the actual and forecasted late payment charges incurred in 2015 and 2016 is captured in the Flow-through deferral account.

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

determined based on the 2016 projected amounts of $0.076 million and $0.243 million, respectively, for a total forecast of $0.319 million.[30]

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.

Table 5-3: 2016 and 2017 NGT Related Recoveries[31]

NGT Related Recoveries, ($ millions)			
	Approved 2016	**Projected 2016**	**Forecast 2017**
NGT Overhead and Marketing Recovery	0.263	0.265	0.332
NGT Tanker Rental Revenue	0.209	0.210	0.448
CNG & LNG Service Revenues	2.426	2.472	3.727
Total NGT Related Recoveries	**2.898**	**2.947**	**4.507**

As discussed in Appendix B, Section 5, 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 2016 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 2017. Please refer to Appendix B, Section 5 for a more detailed discussion of each item.

5.2.5 Biomethane Other Revenue

The other revenue amount of $0.448 million in 2017 shown in Table 5-1 above is the transfer to the delivery margin from 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[32]:

- Upgrading plant cost of service;

[30] 2016 projected amounts are based on six months of 2016 actual information that was available at time of preparing the forecast.

[31] Included in CNG & LNG Service Revenues 2017 forecast line is $0.034 million of revenue associated with compression revenue from the Surrey Ops pump. Appendix B does not include the $0.034 million forecast in revenue associated with the Surrey Ops pump.

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

- Interconnection cost of service for projects introduced after Order G-210-13; and
- Program overhead costs.[33]

For 2017, FEI has transferred the earned return on capital and tax component of the cost of service related to the existing upgrading plants, the City of Surrey Landfill project, and one other 2017 interconnection forecasted to be in-service in 2017 to the BVA by crediting Other Revenue.

With respect to other Biomethane capital expenditures, FEI notes that there is a forecast capital expenditure of $0.302 million[34] 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 Biomethane upgrader O&M and program overhead costs to the BVA is accounted for in FEI's 2016 Approved and 2017 Forecast O&M (Section 11, Schedule 20, Line 34, Column 4).

5.3 *SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE*

The SCP Third Party Revenue for 2016 and 2017 includes the items shown in the table below.

Table 5-4: 2016 and 2017 SCP Revenue Components

Southern Crossing Pipeline Revenue, ($ millions)			
	Approved 2016	**Projected 2016**	**Forecast 2017**
Northwest Natural Gas Co. (NWN)	$ 6.362	$ 6.362	$ 6.421
MCRA	3.600	3.600	3.600
Net Other Mitigation - Spectra / Other	4.995	4.995	4.326
Total SCP Revenue	**$ 14.957**	**$ 14.957**	**$ 14.347**

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.

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

[34] In Section 11, Schedule 4, Line 25, Column 4, the 2017 capital expenditure amount of $1.952 million includes $0.800 million for one new interconnection project and $0.850 million for the City of Surrey interconnection project, where the cost of service is transferred to the BVA, and $0.302 million for the LuLu Island project, where the cost of service is recovered through the delivery margin as per Order G-210-13.

5.3.1 Northwest Natural Gas Co.

The Company 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 2017 Northwest Natural Gas Co. Revenue

Forecast 2017 NWN Revenue, ($ millions)	
NWN Revenue	$ 8.994
Transportation Tolls [(A)]	(2.428)
PG&E Termination Fee	(0.145)
Net NWN Revenue	**$ 6.421**

Notes: (A) Forecast cost of 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. Consistent with Order G-44-12 for 2012 and 2013, in 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 the PBR term.

This treatment 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

For the past number of years, the mitigation revenue associated with the west to east capacity on SCP has been the result of the T-South Enhanced Service agreement between Spectra and FEI. Mitigation revenue associated with the agreement with Spectra is not forecast to continue in 2017 as the agreement expires on October 31, 2016.

In anticipation of the expiry of the agreement with Spectra, the Company has been, and will continue, to seek opportunities to contract the west to east capacity beyond October 31, 2016. To date, FEI has secured a short-term agreement for a portion of the SCP west to east capacity for 2017. Based on the mitigation revenue for the capacity currently contracted and an estimate of the additional mitigation to be achieved for summer 2017, FEI forecasts generating net mitigation revenue in the amount of $4.326 million in 2017.

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 will be 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 to the allocation of a portion the Mt. Hayes LNG facility to gas costs.[35]

The LNG capacity assignment to the gas supply portfolios commenced in 2011 as a result of the Mt. Hayes LNG Facility becoming operational. The costs transferred to gas costs reflect the level of LNG service provided to the gas supply portfolio and is consistent with the level of service provided pre-amalgamation. Generally, this transfer reflects the use of the Mt. Hayes LNG facility for storage services (which is recovered through gas storage and transportation rates) and capacity requirements (which is recovered through delivery rates).

The Mt. Hayes LNG facility includes rate base capital costs and operating costs which are embedded in the delivery margin. The $18.039 million capacity assignment represents a market valuation of avoided storage costs and transport costs on Northwest Pipeline. To properly allocate the capacity assignment value of $18.039 million to the midstream requires an equal offset to the delivery margin which is accomplished by crediting Other Revenue.

The Mt. Hayes cost allocations will be reviewed in the Rate Design Application to be filed by December 31, 2016.

5.5 SUMMARY

FEI has forecast the other revenue components for 2017 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).

[35] The amount is the summation of $12.026 million as set out in the Mt. Hayes Storage and Delivery Agreement approved by the Commission in Order G-161-11 and $6.013 million as approved in Order G-140-09.

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 2017, the formula-O&M is $240.362 million, representing a 0.964 percent increase from the 2016 formula-O&M, entirely due to the formula drivers. O&M expenses forecast outside the formula are $31.135 million, representing a 7.204 percent decrease from the amount approved for 2016. Overall the decrease in Gross O&M Expense from 2016 to 2017 is 0.045 percent.

The components of 2017 O&M expense are shown in Table 6-1 below.

Table 6-1: 2017 O&M Expense

Line No.	Description	$ millions	Reference
1	Formula O&M	240.362	Table 6-2, Line 8
2	Forecast O&M	31.135	Table 6-3, Line 7
3	Total Gross O&M	271.497	
4	Capitalized Overhead (12%)	(32.580)	Section 11, Schedule 20, Line 31
5	Biomethane O&M transferred to BVA	(0.912)	Section 11, Schedule 20, Line 30
6			
7	Net O&M	238.005	

In the subsections below, FEI provides further details on its formula and forecast O&M expenses for 2017.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of Base O&M starts from a base of the 2016 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 2017 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.299 percent and one-half of the prior year's customer growth is 0.675 percent.

For 2017, the annual operating and maintenance expense under the formula is calculated as:

2016 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 2017 Formula O&M.

Table 6-2: Calculation of 2017 Formula O&M

Line No.	Description	Amount ($ millions)	Reference
1	2016 Formula O&M	238.068	FEI 2016 Rates Compliance Filing Schedule 21 Line 31 Column 4
2	Allocation to Fort Nelson	(0.030)	Section 11, Schedule 20, Line 19
3	Adjusted Formula O&M Base	238.038	
4			
5	Net Inflation Factor	0.299%	Section 2 Table 2-4
6	Customer Growth Factor	0.675%	Section 2 Table 2-2
7			
8	2017 Formula O&M	240.362	Line 3 x (1 + Line 5) x (1 + Line 6)

6.2.1 Allocation of O&M to the Fort Nelson Service Area

On June 10, 2015, the Commission issued Order G-97-15 and accompanying decision in FEI's 2015 and 2016 Revenue requirements and Rates Application for the Fort Nelson Service Area (the Fort Nelson Decision).

On page 20 of the Fort Nelson Decision, the Commission Panel discussed FEI's proposal to allocate $24 thousand in communication and line heater fuel costs to the Fort Nelson Service Area that had not been allocated prior to 2013:

> Of concern to the Panel is the movement of communication and line heater fuel costs which were previously centralized in FEI to FEFN. In our view this is very similar to the situation involving intangible plant capital additions which have been denied in Section 4.1.4 of this Decision. These communications and line heater fuel costs already form part of FEI's Base O&M and are being escalated annually in accordance with the PBR Decision. As explained in Section 4.1.4 of this Decision, if the Panel were to accept the transfer of these costs to FEFN as proposed, it would amount to "double dipping." Therefore, the Panel considers moving the communication and line heater fuel costs to FEFN to be inappropriate at this time and denies the inclusion of these costs as part of FEFN's forecast 2015 and 2016 O&M expenses...FEI is directed to identify any other cases where FEI Base Capital or O&M amounts have been allocated to FEFN since approval of the PBR Plan. FEI is further directed to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how the communication and line heater fuel costs can be most appropriately and equitably handled going forward given the current PBR Plan.

FEI acknowledged that its proposal to allocate the communication and line heater fuel costs to the Fort Nelson Service Area should be coordinated with a reduction to FEI's O&M Base.

Given that Fort Nelson Service Area rates had already been set for 2015 and 2016, the earliest year that the transfer of costs could be coordinated was in 2017. FEI therefore proposed that in this Annual Review filing it would adjust its base O&M starting in 2017 for the amount to be allocated to the Fort Nelson Service Area.[36] FEI proposed that this amount would consist of the

[36] In response to Direction 16 in Order G-97-15, FEI described this proposal in its Annual Review for 2016 Delivery Rates Application.

actual 2013 communication and line heater fuel costs of $29 thousand, escalated by the PBR formula. The final calculated amount is a $30 thousand reduction to the FEI 2017 Base O&M (Section 11, Schedule 20, Line 19). These O&M costs have been forecast as part of the Fort Nelson Service Area's revenue requirements starting in 2017.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

After calculating the Formula O&M, the Formula O&M is then adjusted to add in pension and OPEB expense, insurance, O&M supporting Biomethane, NGT and Rate Schedule 46 O&M. These amounts are shown in Table 6-3 below along with a comparison to 2016.

Table 6-3: 2017 Forecast O&M ($ millions)

Line No.	Description	2016 Approved	2016 Projected	2017 Forecast
1	Pension/OPEB (O&M Portion)	24.218	24.218	15.826
2	Insurance	6.275	5.755	5.529
3	Biomethane O&M	1.022	1.071	0.976
4	NGT O&M	1.167	1.168	1.494
5	RS 46 O&M	0.870	1.634	7.310
6				
7	Forecast O&M	33.552	33.845	31.135

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 and Rate Schedule 46 O&M are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expenses for 2017 are based upon recent actuarial estimates using a range of assumptions at December 31, 2015 provided by the Company's actuary, Willis Towers Watson. Pension and OPEB expense is broken out into categories as shown in Table 6-4.

Table 6-4: 2016-2017 Pension and OPEB Expense ($ millions)

Line No.	Description	2016 Approved	2017 Forecast
1	O&M	24.218	15.826
2	Forecast Capital - Growth	1.035	0.676
3	Forecast Capital - Other	3.040	1.987
4	Retirement Costs	1.237	0.809
5	CMAE	0.377	0.246
6			
7	Total Pension & OPEB Expense	29.907	19.544

The table above shows the allocations of pension and OPEB expense to O&M, Capital (Growth and Other), Retirement Costs, and Core Market Administration Expense (CMAE).

Overall, pension and OPEB expense for 2017 is forecast to be $10.363 million lower than what was approved for 2016, of which $8.392 million resides in O&M. This decrease is mainly due to significant actuarial gains on OPEB costs due to a recent actuarial valuation of these plans ($3.9 million), higher membership ($2.3 million) and longer amortization of gains and losses on closed plans ($1.7 million).

The 2016 variance between approved and actual pension and OPEB expense and any 2017 variance between these amounts is captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period as approved 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 2017 insurance expense is forecast at $5.529 million, a decrease of $0.746 million or 12 percent from what was approved for 2016. The 2017 Forecast is calculated by taking the known annual insurance premium of $5.393 million which is applicable to the first six months of 2017 and escalating that amount by five percent for the remaining six months[37]. The five percent escalation is based on a combination of historical increases in premiums, increases in the value of assets year over year and the expectations of Fortis Inc.'s insurance broker on future premiums.

6.3.3 Biomethane O&M

A summary of the 2016 approved and projected and 2017 forecast Biomethane O&M, by project, is provided in Table 6-5 below:

[37] $5.393 million/2 = $2.697 million x 1.05 = $2.832 million. $2.697 million + $2.832 million = $5.529 million.

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

Line No.	Description	2016 Approved	2016 Projected	2017 Forecast
1	Program Overhead	0.453	0.453	0.461
2	City of Surrey Landfill	0.075	0.075	0.011
3	Kelowna upgrader	0.306	0.200	0.312
4	Salmon Arm upgrader	0.125	0.280	0.125
5	New 2017 Project	-	-	0.003
6	**Sub-total - Transferred to BVA**	**0.959**	**1.008**	**0.912**
7	Fraser Valley Biogas	0.011	0.011	0.011
8	Salmon Arm Landfill	0.011	0.016	0.011
9	Kelowna Landfill	0.011	0.011	0.011
10	Seabreeze Farms	0.011	0.016	0.011
11	Lulu Island WWTP	0.011	-	0.011
12	Dicklands Farm	0.011	0.011	0.011
13	**Sub-total - Recovered in delivery rates**	**0.063**	**0.063**	**0.064**
14				
15	**Total Biomethane O&M**	**1.022**	**1.071**	**0.976**

The 2017 forecast of total Biomethane O&M is $0.976 million as shown in the table above. Of this forecast cost, $0.912 million relates to upgrader O&M, interconnection O&M and program overhead[38] which is transferred to the BVA for recovery through the Biomethane Energy Recovery Charge (BERC). The remainder of $0.064 million is the O&M associated with interconnection stations which pre-dated or were approved in Order G-210-13[39], and is recovered through delivery rates.

The 2017 forecast O&M of $0.976 million is $0.046 million lower than the 2016 Approved O&M of $1.022 million due to lower O&M at the City of Surrey landfill as 2016 includes one-time application costs of $75 thousand while 2017 includes the ongoing O&M of $11 thousand. This reduction to O&M is offset mainly by increases for inflation on other projects.

The 2016 Projected O&M of $1.071 million is $0.049 million higher than the 2016 Approved O&M of $1.022 million as a result of higher O&M at Salmon Arm due to higher contaminant levels than projected and the resulting higher material and labour costs to meet pipeline quality specifications. This increase was partially offset by lower O&M due to the shut-down of the

[38] The 2017 forecasted Program Overhead of $461 thousand is comprised of $306 thousand for Customer Education costs, $25 thousand in future development costs and $130 thousand for resourcing. The $306 thousand projection for Customer Education is subject to change depending on the outcome of the proceeding for the FEI Application for Approval of Biomethane Energy Recovery Charge Rate Methodology filed with the Commission August 28, 2015.

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

Kelowna upgrader for the first eight months of 2016 as a result of operational challenges. Production at the Kelowna upgrader is expected to resume in September 2016 with full production later in the year.

6.3.4 NGT O&M

NGT O&M is forecast to increase by $0.327 million from what was approved for 2016. The total NGT O&M of $1.494 million is composed of $1.226 million of NGT station O&M and $0.268 million of LNG tanker and related O&M (Appendix B Sections 5.3 and 6.1.2, and Table B-15). 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 Revenues

The O&M costs to support Rate Schedule 46[40] include all incremental costs associated with the liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers to transport LNG at 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. Specific costs include additional labour, materials, contractors, power, fuel, and fees and administration.

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)

Line No.	Description	2016 Approved	2016 Projected	2017 Forecast
1	Tilbury Plant:			
2	Labour	0.280	0.673	2.160
3	Materials	0.040	0.091	0.170
4	Contractor	0.060	0.320	0.420
5	Power	0.448	0.438	4.060
6	Fuel Gas	0.040	0.040	0.260
7	Fees & Administration	-	0.058	0.120
8	Sub-total	0.868	1.620	7.190
9	Mt Hayes Plant:			
10	Labour	0.001	0.012	0.040
11	Materials	0.001	-	0.005
12	Contractor	-	0.002	0.010
13	Power	-	-	0.060
14	Fuel Gas	-	-	0.005
15	Sub-total	0.002	0.014	0.120
16	Forecast O&M	0.870	1.634	7.310

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

The increase in O&M expenses between the 2016 Approved and 2016 Projected of $0.764 million is the result of increases in projected labour and contractor expenses due to additional resources required for the preparation of operations at the expanded Tilbury LNG facility.[41]

The 2017 Forecast O&M costs to support Rate Schedule 46 are higher than 2016 Approved by $6.440 million, as FEI will be transitioning to using the expanded Tilbury LNG facility to support Rate Schedule 46 once it is complete. As shown in Table 6-6 above, the primary drivers of the increase are labour and power costs. Labour costs are forecast to increase due to additional staff required to support the operations at the new facility and power costs are forecast to increase based on the increase in daily liquefaction.

The $7.310 million forecast for the year 2017 assumes an average LNG supply of approximately 6,100 GJ per day from the Tilbury LNG Facility and an average supply of approximately 205 GJ per day from the Mt. Hayes LNG facility to meet the forecast LNG demand as described in Section 3.5.4, which has more than tripled from the 2016 projection. The majority of the Tilbury LNG supply is projected to be supplied from the expanded Tilbury LNG facility.

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 $0.912 million of Biomethane O&M to the BVA, the net O&M expense is $238.005 million.

6.5 SUMMARY

Overall the decrease in Gross O&M Expense from Approved 2016 to 2017 is 0.045 percent. The formula-driven O&M is increasing at a rate of 0.964 percent with the O&M forecast outside of the formula decreasing at a rate of 7.204 percent. The capitalized overhead rate remains unchanged from 2016.

[41] 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.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

The 2017 Rate Base for FEI is forecast to be $4.141 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 2017 Rate Base of FEI includes the full-year impacts of the 2016 closing projected plant balances as well as the mid-year impact of the following amounts:

- Capital additions, net of Contributions in Aid of Construction (CIAC) additions, resulting from regular capital expenditures, of $189.022 million
- The $443.872 million plant addition of the Tilbury Expansion Project[42]
- Plant depreciation, net of CIAC amortization of $173.210 million
- The capital formula dead band adjustment of $6.118 million[43] 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 $26.465 million.

Details of the 2017 forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 2017 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 2017, the formula-capital is $146.550 million[44], representing a 0.850 percent increase from 2016, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $7.610 million, representing a 30.299 percent decrease from 2016, primarily due to lower pension & OPEB costs and lower spending on NGT assets. Overall, gross regular capital expenditures are forecast to decrease from 2016 to 2017 by 1.235 percent. The components of 2017 regular capital expenditures are shown in Table 7-1 below.

[42] 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.

[43] $6.388 million included as an opening adjustment to Gross Plant in Section 11, Schedule 6.2, Line 38 and ($0.270) million recognized as an opening adjustment to CIAC in Section 11, Schedule 9, Line 7 = $6.118 million.

[44] From Table 7-1 $146.550 million = $33.470 million + 119.658 million - $6.578 million.

Table 7-1: 2017 Regular Capital Expenditures

Line No.	Description	$ millions	Reference
1	Formula Growth Capex	33.470	Table 7-2, Line 6
2	Formula Other Capex (before CIAC)	119.658	Table 7-3, Line 8 - CIAC amount from Line 5 below
3	Forecast Capex	7.610	Table 7-4, Line 5
4	Total Gross Regular Capex	160.738	
5	Less: Formula CIAC	(6.578)	Section 11, Schedule 4, Line 31
6			
7	Net Regular Capex	154.160	

In the subsections below, FEI provides further details on its formula and forecast capital expenditures for 2017.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2016 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 2017 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.299 percent, one-half of the prior year's average customer growth is 0.675 percent and one-half of the prior year's service line additions growth is 0.324 percent. In accordance with Order G-138-14, regular capital expenditure amounts will not be rebased to actual amounts during the 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 2017, the annual capital expenditures under the formula are calculated as:

> 2017 Growth Capital = 2016 Growth capital x [(1 + (I Factor – X Factor)] x [1 + SLA customer growth][45]

> 2017 Other Capital = 2016 Other Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth][46]

Tables 7-2 and 7-3 below show the calculation of the resulting 2017 formula capital expenditures.

[45] SLA customer growth factor as calculated in Section 2, Table 2-2. Formula may also be represented as 2017 Growth Capital = 2016 Growth capital per SLA x [(1 + (I Factor – X Factor)] x 2017 SLA.
[46] This formula is also applied to contributions in aid of construction.

Table 7-2: Calculation of 2017 Formula Growth Capital

Line No.	Description	($ millions)	Reference
1	2016 Formula Growth Capex Base	33.262	FEI 2016 Rates Compliance Filing Schedule 4 Line 16 Column 2
2			
3	Net Inflation Factor	0.299%	Section 2 Table 2-4
4	Customer Growth Factor	0.324%	Section 2 Table 2-3
5			
6	2017 Formula Growth Capex	33.470	Line 1 x (1 + Line 3) x (1 + Line 4)

Table 7-3: Calculation of 2017 Formula Other Capital

Line No.	Description	($ millions)	Reference
1	2016 Formula Other Capex Base	112.053	FEI 2016 Rates Compliance Filing Schedule 4 Line 16 Column 3
2	Allocation to Fort Nelson	(0.066)	Section 11, Schedule 4, Line 17
3	Adjusted Formula Other Capex Base	111.987	
4			
5	Net Inflation Factor	0.299%	Section 2 Table 2-4
6	Customer Growth Factor	0.675%	Section 2 Table 2-2
7			
8	2017 Formula Other Capex	113.080	Line 3 x (1 + Line 5) x (1 + Line 6)

The formula Other Capital amount of $113.080 million is net of CIAC. The amount of CIAC is $6.578 million, which is required to be separated for purposes of the financial schedules and rate calculations. Therefore, the gross formula Other Capital amount is $119.658 million as shown in Table 7-1 above.

7.2.1.1 Allocation of Capital Expenditures to the Fort Nelson Service Area

On June 10, 2015, the Commission issued Order G-97-15 and accompanying decision in FEI's 2015 and 2016 Revenue requirements and Rates Application for the Fort Nelson Service Area (the Fort Nelson Decision).

On page 17 of the Fort Nelson Decision, the Commission Panel discussed FEI's proposal to allocate $62 thousand in Intangible Plant addition to the Fort Nelson Service Area that had not been allocated prior to 2013:

> The Panel is not persuaded that the allocated amounts being charged to FEFN for Intangible Plant additions are appropriate. Moving these costs from FEI to FEFN is based on the premise that a review of fixed asset records indicates that these costs have been inappropriately charged to FEI in the past and moving them to FEFN reflects the correct allocation of costs between FEI and FEFN. The Panel may have been inclined to accept this reasoning were FEI operating under a two-year cost of service regime. However, this is not the case. FEI is operating under a six-year PBR Plan which, among other things, has established a level of base capital under which FEI is to operate. This base capital amount includes the 2013 Intangible Plant additions of $64 thousand and these costs will remain in FEI's Base Capital, escalating based on the PBR formula, for the entire six-year PBR term. Therefore, allowing FEI to allocate these

> costs to FEFN would be effectively facilitating "double dipping." First, by allocating the Intangible Plant expenditures to FEFN, FEI is recovering these costs from the FEFN customer base; and second, since the reallocated costs still remain in the FEI Base Capital amount (i.e. the Base Capital has not been adjusted downwards for the PBR period), the FEI ratepayers are also paying for this same amount in every year of the PBR regime. FEI's shareholders thus benefit through the Earnings Sharing Mechanism despite the fact that no actual "savings" have occurred... FEI is further ordered to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how these costs can be most appropriately and equitably handled going forward given the current PBR Plan in place.

FEI acknowledged that its proposal to allocate the Intangible Plant additions to the Fort Nelson Service Area should have been coordinated with a reduction to FEI's Base Capital.

Given that Fort Nelson Service Area rates had already been set for 2015 and 2016, the earliest year that the allocation of the capital additions could be coordinated was in 2017. In the Annual Review of 2016 Rates, FEI therefore proposed that in its next Annual Review filing it would adjust its Base Capital starting in 2017 for the amounts to be allocated to the Fort Nelson Service Area. FEI proposed that this amount would consist of the actual 2013 Intangible Plant additions of $64 thousand, escalated by the PBR formula. This final calculated amount is a $66 thousand reduction to the FEI 2017 Base Capital (Section 11, Schedule 4, Line 17). These capital additions have been forecast as part of the Fort Nelson Service Area's revenue requirements starting in 2017.

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 which are forecast outside the formula. These amounts are shown in Table 7-4 below along with a comparison to 2016.

Table 7-4: 2017 Forecast Regular Capital Expenditures ($ millions)

Line No.	Description	2016 Approved	2016 Projected	2017 Forecast
1	Pension/OPEB (Capital Portion)	4.075	4.075	2.663
2	Biomethane Interconnect	1.355	0.505	1.952
3	NGT Assets	5.488	5.410	2.995
4				
5	Forecast Regular Capex	10.918	9.990	7.610

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

- The forecast Pension and OPEB capital expenditures of $2.663 million represent the forecast capital portion of the total Pension and OPEB costs for 2017. Pension and OPEB costs are described in Section 6.3.1.
- The forecast Biomethane Interconnect capital expenditures of $1.952 million in 2017 are for three interconnection projects, consisting of the delayed Lulu Island Waste Water Treatment Plant ($0.302 million), the City of Surrey Landfill ($0.850 million), and one other new project ($0.800 million) which is currently at the analysis and early negotiations stage. All three of these projects are expected to be placed into service during 2017. The cost of service for both the City of Surrey Landfill and new 2017 interconnection project will be recovered through the Biomethane Variance Account while the cost of service of the 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 $2.995 million are the forecasts for NGT Fuelling Stations and Tankers (Appendix B, Section 7, Table B-15 amounts of $2.125 million and $0.870 million).

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 2017, FEI is forecasting capital expenditures related to a number of such projects: the Tilbury Expansion Project, the three Coastal Transmission Projects, and the two Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Projects. Only the Tilbury Expansion Project is forecast to be included in rate base and affect delivery rates in 2017. Each project is discussed below.

The cost recovery of expenditures associated with the Tilbury Expansion Project was authorized by Direction No. 5 to the BCUC as amended (Orders in Council Nos. 557 and 749). Under the Order in Council, FEI can spend up to $400 million plus construction carrying costs and feasibility and development costs. Including all of these costs, the Project is forecast at $444 million[47] ($400 million excluding AFUDC and feasibility and development costs). At this time, completion is expected in late 2016, with inclusion in rate base January 1, 2017[48], as reflected in the financial schedules included in Section 11. Should the completion date be delayed until early 2017, FEI will include this in an Evidentiary Update later in 2016. FEI notes that due to the

[47] As shown in the financial schedules in Section 11, Schedule 6.2, Line 38.

[48] OIC 749 states "In setting rates under the Act for FortisBC Energy Inc., the commission must do all of the following:

a) On January 1 of the year immediately following the year in which phase 1A facilities are completed, include in the utility's natural gas class of service rate base the sum of the following:
    - (i.) the lesser of
        - A. the capital costs of the phase 1A facilities, and
        - B. $400 million;
    - (ii.) the construction carrying costs for the phase 1A facilities;
    - (iii.) the feasibility and development costs incurred on or after January 1, 2013;"

existence of the Flow-through deferral account, only the actual amount of depreciation expense, financing costs or tax expense will be recovered from ratepayers.

The Coastal Transmission Projects for which there will be capital expenditures in 2016 and 2017 are the Cape Horn to Coquitlam, Nichol to Port Mann and Nichol to Roebuck projects. These projects involve the installation of 11 kilometers of transmission pressure pipeline in the City of Surrey and the City of Coquitlam and are intended to increase security of supply by reducing the number of single points of failure. Cost recovery in rates for these projects is authorized by Direction No. 5 to the BCUC as amended (Orders in Council Nos. 557 and 749). FEI anticipates spending $19.899 million on these projects in 2016 and a further $130.295 million[49] in 2017, with total forecasted spending of $170.479 million including AFUDC on all three projects, with an expected in-service date of November 2017. Based on current forecasted completion dates, these projects will be added to rate base January 1, 2018 and are therefore not included in 2017 delivery rates.

The LMIPSU CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU includes the Coquitlam Gate IP Project which will address an increasing number of gas leaks on the Coquitlam Gate IP line and restore operational flexibility and resiliency to the Metro Vancouver IP system and the Fraser Gate IP Project which will provide required seismic upgrades to the Fraser Gate IP line. Both the Fraser Gate IP and the Coquitlam Gate IP Projects are expected to be in-service at the end of 2018. The estimated capital cost for the LMIPSU Projects, including AFUDC and abandonment/demolition costs, is $254.780 million. In 2016 and 2017, FEI has forecast expenditures of $10.572 million and $21.309 million[50], respectively.

7.3 *2017 PLANT ADDITIONS*

The 2017 Plant Additions are comprised of FEI's 2017 regular capital expenditures from Section 7.2 above plus the Tilbury Expansion Project, 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, AFUDC, and 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.

[49] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 12.
[50] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 11.

Table 7-5: Reconciliation of Capital Expenditures to Plant Additions

Line No.	Description	$ millions	Source
1	Formula Growth Capex	33.470	Table 7-2
2	Formula Other Capex	113.080	Table 7-3
3	Forecast Capex	7.610	Table 7-4
4	Total Net Regular Capex	154.160	
5	Formula CIAC	6.578	Table 7-1
6	Total Gross Regular Capex	160.738	
7	Capitalized Overheads	32.580	Table 6-1
8	AFUDC	2.282	Section 11, Schedule 5, Line 23
9	Total Regular Additions to Plant	**195.600**	
10			
11	Special Projects and CPCN Capex	164.036	Section 11, Schedule 5, Line 28
12	Special Projects and CPCN AFUDC	6.887	Section 11, Schedule 5, Line 29
13	Change in Special Projects and CPCN Work in Progress	272.949	Section 11, Schedule 5, Line 31
14	Total Special Projects and CPCN Additions to Plant	**443.872**	
15			
16	Total 2017 Plant Additions	**639.472**	

7.4 ACCUMULATED DEPRECIATION

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

The depreciation rates used for 2017 are the same as the depreciation rates that were proposed by FEI in its Annual Review for 2016 Rates, based on the utility's most recent depreciation study. While those rates were not approved for 2016 through Commission Order G-193-15, FEI has received Commission Order G-119-16 approving the proposed depreciation and net salvage rates effective January 1, 2017. 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 2017 depreciation expense is calculated as $171.504 million[51].

7.5 DEFERRED CHARGES

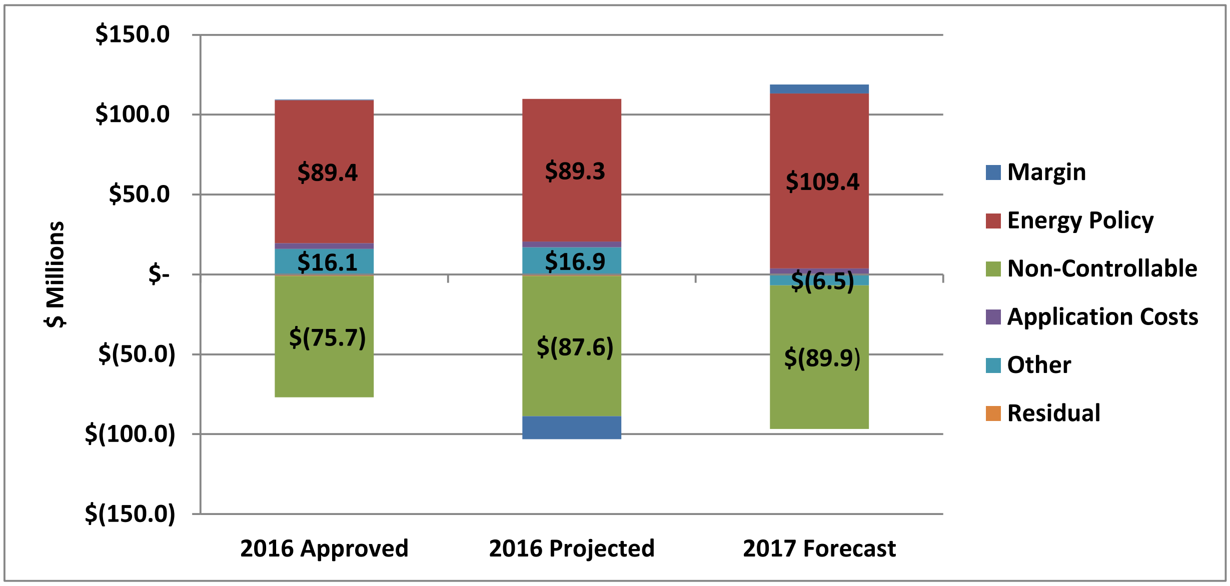
The forecast mid-year balance of unamortized deferred charges in rate base for FEI is $22.249 million in 2017 and this balance is driven largely by the balances in several deferral accounts including the Energy Efficiency and Conservation, Revenue Stabilization Adjustment

[51] $180.466 million depreciation expense as calculated in Section 11 Schedule 21, Line 5 less $8.962 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

Mechanism, Gains and Losses on Asset Disposition, NGT Incentives, 2011 Customer Service O&M and COS deferral and Whistler Pipeline Conversion deferrals, while partially offset by the net variance between the Pension and OPEB Funding accounts, the Negative Salvage Provision account, Midstream Cost Reconciliation Account, Commodity Cost Reconciliation Account, Pension and OPEB Variance Account and Customer Service Variance Account.

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 2017 amortization expense is calculated as $42.592 million[52]. 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 proposing to create the following new deferral account discussed below.

7.5.1.1 All-Inclusive Code of Conduct / Transfer Pricing Policy Application

In accordance with Order G-65-15, FEI has filed an application for approval of an all-inclusive Code of Conduct and Transfer Pricing Policy covering the interactions between FEI and its affiliated natural monopoly utilities, FEI and its affiliated non-regulated businesses, and FEI and

52 Total of Section 11, Schedule 11.1, Line 34, Column 6 and Schedule 12, Line 13, Column 6.

its affiliated regulated businesses operating in a non-natural monopoly environment (the All-Inclusive CoC/TPP). FEI has incurred, and will incur, further costs related to legal fees, consultant costs, costs for miscellaneous facilities, stationery and supplies, Commission costs and Participant Assistance/Cost Award (PACA) reimbursements related to the proceeding, which have been estimated at $155 thousand.

In this Application, FEI is seeking approval for a rate base deferral account to record the costs related to the All-Inclusive CoC/TPP and to amortize these costs over one year in 2017. FEI believes this amortization period is appropriate given the relatively small amount of additions forecasted to the account and the minimal rate impact to customers. Any variances between the forecast additions and the actual incurred costs will be amortized in rates the following year.

7.5.2 Existing Deferral Accounts

FEI is proposing recovery of the two deferral accounts discussed below.

7.5.2.1 2016 Cost of Capital Application

As part of Decision G-75-13 relating to the GCOC Stage 1 Proceeding, FEI was directed to file an application for the review of its common equity component and the ROE. FEI has incurred and will incur further costs related to legal fees, consultant costs, costs for miscellaneous facilities, stationery and supplies, Commission costs and PACA reimbursements related to the proceeding, which have been estimated to be $1.7 million. Commission Order G-86-15 granted approval for FEI to capture the costs related to the 2016 Cost of Capital proceeding in a rate base deferral account.

In this Application, FEI is seeking approval to amortize these costs over three years beginning in 2017. This amortization period is appropriate as it will smooth the rate impact on customers.

7.5.2.2 Emissions Regulations Deferral Account

As part of the 2012-2013 Revenue Requirement Application, FEI requested approval of an Emissions Regulations Deferral Account due to a growing number of regulations around emissions trading that could lead to incremental compliance costs and recoveries. Given the uncertainty around the final form and applicability of emissions trading regulations, FEI requested approval for a rate base Emissions Regulations Deferral Account to capture potential compliance costs and revenues collected from credits.

Commission Order G-44-12 approved the establishment of the Emissions Regulations Deferral Account. Further, the Order stated that in the event that FEI determined that costs and/or revenues have occurred that should accrue to the deferral account, it is to provide to the Commission a detailed description of the accounting methodologies that are being used to track and record such costs and/or revenues.

In 2016, FEI collected pre-tax revenues of $2.4 million ($1.8 million after-tax) from the sale of credits earned under the Renewable Low Carbon Fuel Requirements Regulation

(RLCFRR). The RLCFRR was introduced in order to reduce the carbon intensity of transportation fuels. The carbon intensity of both compressed natural gas (CNG) and liquefied natural gas (LNG) fall below the maximum carbon intensity limit set by the RLCFRR; therefore FEI earns credits from the sale of CNG and LNG for use in transportation applications. FEI issues a request for proposal to potential buyers to ensure it maximizes the value of these credits for the benefit of ratepayers. FEI will continue to generate credits in the future as the sale of CNG and LNG for transportation increases.

These revenues, as well as any future credits received under the RLCFRR, are recorded directly in the deferral account. Any costs related to the administration of these sales, not already embedded in formula O&M, will be tracked by charging the costs to an internal order within the deferral account.

In this Application, FEI is seeking approval to amortize the balance in this deferral account over five years, beginning in 2017. This amortization period is appropriate given that FEI expects to continue to receive revenues which will vary depending on the number of credits FEI earns under the RLCFRR and the price at which FEI is able to sell those credits. The longer recovery period of five years will help smooth the rate impact on customers as these revenues are received from time to time.

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 2016 Q1 gas cost report and historical volumes. Materials and supplies and refundable contributions are forecast based on 2016 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, 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 new and changed 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 interim 2016 benchmark capital structure of 61.5 percent debt and 38.5 percent equity and Return on Equity (ROE) of 8.75 percent as approved by Order G-75-13. FEI is awaiting a decision on its approved capital structure and ROE for 2016 and 2017 and will update its rate calculations once that decision is reached. The 2017 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 2017 (which is equal to its after-tax weighted average cost of capital) is 5.64 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-75-13, 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, 2013 until December 31, 2015, with an Automatic Adjustment Mechanism (AAM) in place.

The AAM was not triggered for 2014 or 2015, such that the ROE percentage remained as approved in Order G-75-13. FEI has therefore prepared this Application using an ROE of 8.75 percent and a common equity percentage of 38.5 percent. As part of Order G-75-13, the Commission directed FEI to file a cost of capital application no later than November 2015, for determination of cost of capital for periods beyond December 31, 2015. That application was filed and a decision is expected to be received before the proceeding relating to this Application is final. Any changes to the ROE or capital structure that result from that proceeding will be reflected in an Evidentiary Update to this proceeding.

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 (unfunded) debt.

8.3.1 Long-Term Debt

FEI is a public issuer of long-term debt. During April 2016, FEI issued long term debt of $150 million[53] at a rate of 2.58 percent for a term of 10 years, and $150 million at a rate of 3.67

[53] Only $118.5 million of which is financing FEI's rate base in 2017 as the remainder finances the non-rate base Lower Mainland Acquisition Premium.

percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Corporation's capital expenditure program. In 2016, FEI plans to issue additional long-term debt of up to $200 million, which will be used to refinance a $200 million PMM with a coupon rate of 10.3 percent maturing on September 30, 2016. This debt issuance is reflected in the financial schedules in November 2016 at a rate of 3.90 percent. No long-term debt issues are planned for 2017. The exact timing, amount and rate of the issuance will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of 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 2021. The credit facility provides FEI with required liquidity should there be constraints issuing debt 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 does not currently expect to issue long term debt in 2017; however, the estimated issue rate for 2017 is approximately 4.10 percent based on a 30 year GOC rate of 2.35 percent and an indicative spread of 1.77 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. CDOR is not forecast by economists either; therefore, 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 0.49 percent in 2016 to approximately 0.59 percent in 2017. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast[54]

FEI Short Term Interest Rate	2016	2017
3 Month T-Bill Rate[1]	0.49%	0.59%
Spread to CDOR	0.35%	0.35%
CDOR Rate	0.84%	0.94%
Spread to CP	-0.18%	-0.18%
CP Dealer Commission	0.10%	0.10%
Standby Fee on Undrawn Credit[2]	0.34%	0.45%
Upfront Fee on Undrawn Credit	0.09%	0.12%
FEI Short Term Rate (Rounded)	1.20%	1.40%

Note 1 - 3 month T-Bill rate for 2016 based on a composite of actual historical rates up to March 31, 2016 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 2017 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 2017 (which is equal to its after-tax weighted average cost of capital) is 5.64 percent. The calculation of the rate is shown in the following table.

[54] The 2016 short term rate is projected and compares to the 2016 approved short term rate of 1.25%.

Table 8-2: Calculation of AFUDC Rate for 2017

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	6.15%	1.40%	1.04%	1.40%
Long Term Debt	55.35%	5.40%	4.00%	5.40%
Common Equity	38.50%	11.82%	8.75%	8.75%
Weighted Average	100.00%	7.63%	5.64%	6.44%

8.4 SUMMARY

FEI's capital structure and ROE have been forecast for 2017 at the same percentages as approved for 2015 and will be updated once a decision is reached on the 2016 capital structure and ROE. 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 remaining relatively stable. With the retirement of the $200 million PMM with a coupon rate of 10.3 percent in September 2016 and the replacement debt forecast to be issued at a significantly lower rate, FEI customers will realize a significant savings in interest costs in 2017 once the full-year impact of the lower interest rate is realized.

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 2017, property taxes are forecast to increase 7.0 percent from 2016 Approved, while income tax is forecast to increase by 0.01 percent compared to 2016 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 2017 of $67.450 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 2016	Projected 2016	Forecast 2017
Distribution Assets	$ 23.667	$ 23.993	$ 24.958
Transmission Assets	17.616	17.666	17.845
Gas Storage Assets	4.422	5.429	7.712
Manufactured Gas Assets	0.029	0.029	0.031
General Assets	3.493	3.735	3.991
In-Lieu	13.522	13.168	12.629
OGC Fees	0.294	0.295	0.295
Total Property Taxes	$ 63.043	$ 64.315	$ 67.461
Less: Property Tax Transferred to BVA	(0.007)	(0.007)	(0.011)
Net Property Tax Expense	$ 63.036	$ 64.308	$ 67.450
Forecast Change from 2016 Approved			7.0%
Forecast Change from 2016 Projected			4.9%

As shown in the table above, in 2017 property taxes are forecast to increase by 7.0 percent from 2016 Approved and increase 4.9 percent compared to 2016 Projected. In general, the increase from 2016 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 based on FEI's average annual change in the tax rate applicable to FEI over the past 3 to 5 years. On average:

   a. Municipal rates are expected to decrease by 1.0 percent;
   b. School rates are expected to decrease by 0.7 percent;
   c. Rural rates are expected to decrease by 0.8 percent; and
   d. Other rates are expected to increase by 3.0 percent.

2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to decrease by 4.10 percent. As grants in-lieu of taxes are based on a fixed percentage of revenues, the overall decrease in revenues reported to municipalities decreases 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 0.5 percent increase in assessed values of distribution lines and services plus additional new construction of approximately $25 million;
   b. A 0.5 percent increase in assessed values of transmission lines;
   c. A 2.0 percent increase in assessed values for LNG assets plus an expected increase of approximately $62 million for new construction at the Tilbury LNG facility; and
   d. Land value changes which are expected to range from a 2.0 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 26 percent for 2017, which is unchanged from 2016. 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 will be updated each year as part of the annual rate setting process.

Income tax for 2017 is forecast to increase by $0.007 million or 0.01 percent compared to 2016 Approved. This increase is primarily due to a higher delivery margin in 2017 offset by an increase in capital cost allowance deductions in 2017.

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 of BC introduced an LNG income tax on net income from LNG facilities in BC. The new LNG income tax will 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. The new legislation is not yet in force.

The new LNG income tax is 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). The new tax will apply to income earned at the existing Tilbury Facility, the Tilbury Expansion and the Mt. Hayes LNG Facility on Vancouver Island.

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

Because the LNG income tax legislation is not yet in force, estimates of the LNG income tax and NGTC have not been included in forecast 2017 rates. If the legislation comes into force before FEI files for its final rates later in 2016, FEI will update the financial schedules to include the forecast impacts of the tax and the difference between the forecast and actual tax will be captured in the Flow-through deferral account. If the LNG income tax does not come into force before then, the entire actual amount of the LNG income tax net of the NGTC will be captured in the Flow-through deferral account when it becomes effective.

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 RIDERS

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 2017, FEI is proposing to distribute a $5.115 million pre-tax credit ($3.785 million after tax) as shown in Table 10-1 below. This amount is composed of:

- 2016 projected sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth;
- The true-up of the 2015 projected earnings sharing to actual; and
- Financing on the deferral account balance.

Table 10-1: Summary of Earnings Sharing to be Returned in 2017 ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2016 Projected Sharing	(3.662)	Table 10-2, Line 50
2	Actual Customer Growth adjustment	0.228	Table 10-3, Line 34
3	2015 Projected vs. Actual ending balance true-up	(0.108)	Table 10-4, Line 3
4	Financing	(0.243)	Table 10-5, Line 5
5			
6	**2017 after-tax amount returned to customers**	**(3.785)**	
7	**2017 pre-tax amount returned to customers**	**(5.115)**	Line 6 / 0.74

Each of these items is discussed in the sections below.

10.1.1 2016 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[55] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[56]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

As discussed in Section 1.4, FEI is projecting 2016 formula-driven O&M savings at $11.1 million, and 2016 capital expenditures in excess of the formula by $13.767 million. The $13.767 million excess 2016 capital expenditures will exceed the dead band by $6.118 million, such that FEI has removed the $6.118 million amount above the dead band in the calculation of 2016 earnings sharing, as shown in Line 31 of Table 10-2 below.

[55] Excluding items that are reforecast outside of the formula.
[56] Ibid.

Table 10-2: Calculation of 2016 Projected Earnings Sharing ($millions)

Line No.	Particulars					Reference
1	Approved Formula O&M	238.068				G-193-15
2						
3	Actual/Projected Gross O&M	260.813				
4	Less: O&M Tracked outside of Formula					
5	Pension/OPEB (O&M portion)	24.218				
6	Insurance	5.755				
7	Biomethane	1.071				
8	NGT O&M	1.168				
9	RS 16/46 O&M	1.634				
10	Total	33.845				Sum of Lines 5 through 9
11						
12	Actual/Projected Base O&M	226.968				Line 3 - Line 10
13						
14	O&M Subject to Sharing	(11.100)				Line 12 - Line 1
15						
16			Annual Capital Expenditures			
17		Cumulative	2014	2015	2016	Note 1
18						
19	Formula CapEx	404.516	119.821	139.380	145.315	
20						
21	Total Regular CapEx	497.508	144.932	174.489	178.087	
22	Less: CapEx tracked outside of formula					
23	Pension and OPEB	12.314	3.915	4.324	4.075	
24	NGT	12.576	5.816	1.350	5.410	
25	Biomethane	9.768	3.656	5.607	0.505	
26	CIAC	17.270	4.419	6.336	6.515	
27	AFUDC	8.520	2.727	3.293	2.500	
28	Total	60.449	20.533	20.911	19.005	Sum of Lines 23 through 27
29						
30	Actual/Projected Base CapEx	437.059	124.399	153.578	159.082	Line 21 - Line 28
31	Dead Band Adjustment	(6.118)		-	(6.118)	Adjustment to stay with deadband
32	Actual/Projected Base CapEx for ESM Calculation	430.941	124.399	153.578	152.964	Line 30 + Line 31
33						
34	Actual/Projected Cumulative Base CapEx Variance	26.425	4.578	14.198	7.649	Line 32 - Line 19
35						
36	Single Year Deadband % Variance (after adjustment)		3.70%	9.88%	5.12%	Line 34 / (Line 19 + Line 23)
37	Two year Cumulative Deadband % Variance (after adjustment)			13.58%	15.00%	Line 36 sum of two years
38						
39	Equity Component of Rate Base	38.50%				
40	Approved Return on Equity	8.75%				
41	After Tax CapEx Subject to Sharing	0.890				Product of Lines 34, 39 & 40
42	Tax Rate	26%				
43						
44	Before Tax CapEx Subject to Sharing	1.203				Line 41 / (1 - Line 42)
45						
46	Total before tax Sharing Amount	(9.897)				Line 14 + Line 44
47	Sharing percentage	50%				G-138-14
48						
49	2016 Projected Earnings Sharing (pre-tax)	(4.949)				Line 46 x Line 47
50	2016 Projected Earnings Sharing (after-tax)	(3.662)				Line 49 x 0.74

Notes

1 2014 & 2015 are actual results from BCUC Annual Report, 2016 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 $0.308 million debit ($0.228 million debit after-tax) for 2015 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 2015	986,765	
2	Average Customers 2014	959,193	
3	Growth in Average Customers	27,572	Line 1 - Line 2
4	Average Customer Growth	2.874%	Line 3 / Line 2
5		50%	G-138-14
6	Average Customer Growth to be recast in Formula	1.437%	Line 4 x Line 5
7	2015 Net Inflation Factor	0.201%	G-193-15 Compliance filing, Section 11, Schedule 3, Line 9, Column 4
8	2014 Reforecast Sustainment/Other Capital	$ 111.862	Note 1
9	2015 Reforecast Formulaic Sustainment/Other Capital	$ 113.698	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2015 Year Formulaic Sustainment/Other Capital	110.901	G-193-15 Compliance filing, Section 11, Schedule 4, Line 13, Column 3
11	Sustainment/Other Capital Increase from actual growth	$ 2.797	Line 9 - Line 10
12			
13			
14	Service Line Additions 2015	12,399	
15	Service Line Additions 2014	11,099	
16	Growth in Average Customers	1,300	Line 14 - Line 15
17	Average Customer Growth	11.71%	Line 16 / Line 15
18		50%	G-138-14
19	Average Customer Growth used in Formula	5.86%	Line 18 x Line 17
20	2014 Reforecast Service Line Additions	10,961	Note 2
21	2015 ReForecast Service Line Additions	11,603	Line 20 x (1 + Line 19)
22	Service Line Addition Cost per Customer ($)	2,971	2015 Annual Review of Rates, Section 11, Schedule 18, Column 6, Line 21
23	2015 Reforecast Formulaic Growth Capital	$ 34.472	Line 21 x Line 22 / 1000000
24	2015 Formulaic Growth Capital	28.479	G-193-15 Compliance filing, Section 11, Schedule 4, Line 13, Column 2
25	Growth Capital Increase from actual growth	$ 5.993	Line 23 - Line 24
26			
27			
28	Increase in Capital Requirements from Actual Growth	$ 8.790	Line 11 + Line 25
29	Mid Year	$ 4.395	Line 28 / 2
30			
31	Equity Cost Component	3.37%	G-193-15
32	Debt Cost Component	3.64%	G-193-15
33	Earned Return on incremental Capital Requirements (pre-tax)	$ 0.308	Line 29 x (Line 31 + Line 32)
34	Earned Return on incremental Capital Requirements (after-tax)	$ 0.228	Line 33 x 0.74

Notes

1. 2016 Annual Review of Rates Table 10-1, Line 9 plus FEVI & FEW additions to base from 2015 Annual Review of Rates, Section 11, Schedule 18, Column 5, Lines 29 & 30
2. 2016 Annual Review of Rates Table 10-1, Line 21 plus FEVI & FEW additions to base from 2015 Annual Review of Rates, Section 11, Schedule 18, Column 5, Lines 17 & 18

10.1.3 True-Up for 2015 Actual Earnings Sharing

In FEI's 2015 Annual Report to the Commission, FEI calculated the final 2015 earnings sharing based on the final 2015 results. The final amount of earnings sharing for 2015 was $4.194 million, which was $0.108 million higher than the $4.086 million projected for 2015 as shown in Table 10-4 below. As a result, FEI is increasing its 2017 earning sharing by the after-tax amount of $0.108 million as shown in Table 10-1 above.

Table 10-4: Calculation of 2015 Actual Earnings Sharing true-up ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2015 Actual Earnings Sharing account ending balance	(4.194)	2015 FEI BCUC Annual Report
2	2015 Projected Earnings Sharing account ending balance	(4.086)	Annual Review of 2016 Rates Compliance Filing financial schedules, Schedule 12, Line 11, Column 2
3	**2015 Earnings Sharing account true-up**	**(0.108)**	

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 $0.142 million credit to true-up for 2016 projected financing and a forecast $0.101 million credit for 2017 financing. This results in a total after-tax financing adjustment of $0.243 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	2016 Projected Earnings Sharing financing	(0.264)	
2	Less: 2016 Forecasted Earnings Sharing financing	(0.122)	Annual Review of 2016 Rates Compliance Filing financial schedules, Schedule 12, Line 11, Column 4
3	2016 Earnings Sharing financing true-up	(0.142)	
4	Add: 2017 Forecasted Earnings Sharing financing	(0.101)	Section 11, Schedule 12, Line 8, Column 4
5	**2016/2017 Financing Adjustments**	**(0.243)**	

10.1.5 Summary of Earnings Sharing

After calculating the 2016 projected earnings sharing and including the adjustments described above, FEI proposes to distribute $5.115 million to customers in 2017 as a reduction in 2017 revenue requirements through amortization of the projected 2017 opening after-tax balance of $3.785 million in the Earnings Sharing deferral account.

As part of the Annual Review for 2018 Rates, the earnings sharing for 2016 will be subject to similar true-ups as described above which account for the actual O&M and capital expenditure amounts for 2016, as well as impacts, if any, associated with non-performance of Service Quality Metrics, based on final 2016 results.

10.2 *RATE RIDERS*

There are three delivery rate riders that are set each year through the annual review process. These are the RSDA Rate Riders, the Phase-In Rate Riders, and the RSAM Rate Riders. Each of these is discussed separately below.

10.2.1 RSDA Rate Riders

The RSDA Rate Riders were designed to distribute the ending 2014 Vancouver Island RSDA balance to Mainland customers by the end of 2017.

In the Annual Review for 2016 Rates, FEI calculated the 2016 rate riders based on the forecast demand for the Mainland service area of 164,023.4 TJs[57]. The current projection for 2016 demand for the Mainland service area is 168,534.3 TJs. Because of the differences in the original forecast and projected 2016 demand, the 2016 projected ending balance in the RSDA is higher than it was in FEI's 2016 Annual Review. Based on this updated demand forecast, FEI projects the 2016 ending balance in the RSDA to be $20.555 million. Table 10-6 below shows the projected and forecast continuity of the RSDA and its disposition through 2016 and 2017.

Table 10-6: 2016 and 2017 RSDA Balances ($000s)

RSDA Continuity	2016	2017	Notes/ Reference
Opening Balance	$ (64,322)	$ (20,555)	
Projected Disposition through Rider (before interest is added)	44,273	20,555	1, 2
Net	$ (20,049)	$ -	
Interest	(506)	(144)	3
Closing Balance	$ (20,555)	$ (144)	
Total Amount to be disbursed through Rider		$ 20,699	4

Table Notes:

1. $44,273 is based on 2016 Approved Riders by Rate Schedule multiplied by the latest 2016 Projected Volume by Rate Schedule
2. This is the last year of the phase in so 100% of the RSDA balance is to be distributed to Mainland customers
3. Interest Rate for 2016 and 2017 equals 1.20% and 1.40% respectively
4. $20,699 = $20,555 + $144

As approved by the Commission, the 2017 RSDA Rate Riders are applicable to Mainland customers only. Based on the current projected 2016 ending balance of the RSDA, the 2017 forecast demand for the Mainland service area, and returning the remaining forecasted 2017 opening balance amount plus forecasted 2017 financing to customers, the 2017 RSDA Rate

[57] FEI Annual Review for 2016 Rates, Order G-193-15 Compliance Filing.

Riders by rate schedule are shown in Table 10-7 below. The calculation of the rate riders is designed to fully distribute the RSDA to Mainland customers in 2017. Any variances between the actual and forecast volumes for 2016 or 2017 will result in a balance remaining at the end of 2017.

Table 10-7: 2017 RSDA Riders

	2017 RSDA ($000s)	2017 RSDA Interest ($000s)	Total ($000s)	2017 Volume	2017 RSDA Rider ($/GJ)
Rate 1/1B/1U/1X	$ (12,397)	$ (87)	$ (12,484)	68,608	$ (0.182)
Rate 2/2B/2U/2X	(3,220)	(23)	(3,243)	25,165	$ (0.129)
Rate 3/3B/3U/23/3X	(2,647)	(19)	(2,665)	24,710	$ (0.108)
Rate 4 (off-peak)	(11)	(0)	(11)	148	$ (0.072)
Rate 4 (extension)	-	-	-		$ (0.072)
Rate 5/5B/25	(1,094)	(8)	(1,102)	14,765	$ (0.075)
Rate 6/26	(9)	(0)	(9)	54	$ (0.161)
Rate 6A	-	-	-		$ (0.161)
Rate 6P	-	-	-		$ (0.161)
Rate 7/27	(302)	(2)	(304)	6,408	$ (0.047)
Rate 22	(456)	(3)	(459)	13,435	$ (0.034)
Rate 22A: Firm MTQ	(315)	(2)	(317)	9,702	$ (0.033)
Rate 22A: Interruptible MTQ	-	-	-		$ (0.033)
Rate 22B: Elkview Coal - Firm MTQ	(14)	(0)	(14)	1,698	$ (0.008)
Rate 22B: Elkview Coal - Interruptible MTQ - Apr. 1 to Nov. 1	-	-	-		$ (0.008)
Rate 22B: Elkview Coal - Interruptible MTQ - Nov. 1 to Apr.1	-	-	-		$ (0.008)
Rate 22B: Columbia except Elkview - Firm MTQ	(92)	(1)	(92)	4,846	$ (0.019)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Apr. 1 to Nov. 1	-	-	-		$ (0.019)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Nov. 1 to Apr.1	-	-	-		$ (0.019)
Total of Rate 22	(876)	(6)	(882)	29,680.7	
Grand Total	**$ (20,555)**	**$ (144)**	**$ (20,699)**	**169,539.6**	

As 2017 is the last year that the RSDA Rate Riders are applicable, FEI will seek approval for disposition of any 2017 closing balance in the RSDA deferral account in its Annual Review for 2018 Rates.

10.2.2 Phase-In Rate Riders

The Phase-in Rate Riders are designed to phase-in the rate decrease to Vancouver Island and Whistler customers, and the offsetting rate increase for Mainland customers, due to amalgamation of the utilities, allowing all customers to have the same underlying delivery rate. The amount of the riders decreases over the three years 2015 through 2017; the riders were designed to be eliminated by 2018.

The 2017 Phase-in Rate Riders collected from Vancouver Island and Whistler customers are calculated to offset the rate reduction due to the implementation of common rates by 20 percent for Rate Schedule 1 and Rate Schedule 2 customers, 10 percent for Rate Schedule 3 customers, 25 percent for Vancouver Island Rate Schedule 5 and 25 customers and 10 percent for Whistler Rate Schedule 5 and 25 customers.[58] The Phase-in Rate Rider for Mainland customers is then designed to distribute to Mainland customers the amount forecast to be collected from Vancouver Island and Whistler customers. Two adjustments must be made to the Phase-in Rate Riders, as explained below.

[58] These are the percentages for 2017 approved through Commission Order G-131-14.

First, the 2016 projected volume variance (or imbalance) in the Phase-in Rider Balancing Account must be accounted for when setting the 2017 Mainland Phase-in Riders. The variance in this account is the difference between the projected amount collected from Vancouver Island and Whistler customers less the projected disbursement to Mainland customers. The difference, or imbalance, is then added to the Mainland disbursement rider (and not the Vancouver Island and Whistler collection rider) because the intention is to phase-in Vancouver Island and Whistler customers with the resulting amount collected being distributed to Mainland customers.

The amount of the rate rider for 2017 collected from Vancouver Island and Whistler customers, including the 2016 imbalance in the Phase-in Rider Balancing Account, is shown in Table 10-8 below.

Table 10-8: 2017 Rate Rider Collected from Vancouver Island and Whistler Customers Excluding Amalgamation Costs

			2017		
	Difference ($/GJ)	Phase-In %	($/GJ)	(TJ)	thousand)
FEVI RS1/1B	$ 4.12	20%	$ 0.824	5,414.2	$ 4,461
FEW RS1/1B	$ 7.86	20%	$ 1.573	257.3	$ 405
FEVI RS2/2B	$ 4.69	20%	$ 0.938	3,114.4	$ 2,921
FEW RS2/2B	$ 8.67	20%	$ 1.734	243.1	$ 422
FEVI RS3/3B/23	$ 3.48	10%	$ 0.348	2,764.9	$ 962
FEW RS3/3B/23	$ 9.23	10%	$ 0.923	321.8	$ 297
FEVI RS4 (off-peak)*			$ 0.348	-	$ -
FEVI RS4 (extension)*			$ 0.348	-	$ -
FEW RS4 (off-peak)*			$ 0.923	-	$ -
FEW RS4 (extension)*			$ 0.923	-	$ -
FEVI RS5/5B/25	$ 5.03	25%	$ 1.259	1,029.8	$ 1,297
FEW RS5/5B/25	$ 9.23	10%	$ 0.923	44.6	$ 41
FEVI RS6/26*			$ 0.348	-	$ -
FEW RS6/26*			$ 0.923	-	$ -
FEVI RS7/27	$ 3.48	10%	$ 0.348	154.9	$ 54
FEW RS7/27*			$ 0.923		$ -
FEVI R22*			$ 0.348	-	$ -
FEW R22*			$ 0.923	-	$ -
Total				13,345.0	$ 10,860

Phase-In Rider Imbalance	2016	
Opening Phase-In Rider Balancing Account	$ 500	
Projected collections from Vancouver Island & Whistler	21,813	
Projected disbursements to Mainland	(17,794)	
Projected imbalance as adjustment to Mainland disbursement		$ 4,519
2017 Disbursement to Mainland Customers		$ 15,378

**There are no 2017 forecasted volumes for these rate classes, therefore rate riders from FEVI and FEW Rate Schedule 3 have been assigned.*

These 2017 collections and 2016 imbalance result in the following Phase-in Rate Riders for Mainland customers in 2017.

Table 10-9: Phase-in Rate Rider Calculation for Mainland Customers

	Allocation		2017	
	%	$ thousands	Volume (TJ)	Rider ($/GJ)
Rate 1/1B/1U/1X	60.3%	$ (9,275)	68,607.9	$ (0.135)
Rate 2/2B/2U/2X	15.7%	$ (2,409)	25,165.4	$ (0.096)
Rate 3/3B/3U/23/3X	12.9%	$ (1,980)	24,709.7	$ (0.080)
Rate 4 (off-peak)	0.1%	$ (8)	148.2	$ (0.054)
Rate 4 (extension)	0.0%			$ (0.054)
Rate 5/5B/25	5.3%	$ (819)	14,765.1	$ (0.055)
Rate 6/26	0.0%	$ (6)	54.2	$ (0.120)
Rate 6A	0.0%			$ (0.120)
Rate 6P	0.0%			$ (0.120)
Rate 7/27	1.5%	$ (226)	6,408.4	$ (0.035)
Rate 22	2.2%	$ (341)	13,435.3	$ (0.025)
Rate 22A: Firm MTQ	1.5%	$ (235)	9,701.6	$ (0.024)
Rate 22A: Interruptible MTQ	0.0%			$ (0.024)
Rate 22B: Elkview Coal - Firm MTQ	0.1%	$ (10)	1,698.2	$ (0.006)
Rate 22B: Elkview Coal - Interruptible MTQ - Apr. 1 to Nov. 1	0.0%			$ (0.006)
Rate 22B: Elkview Coal - Interruptible MTQ - Nov. 1 to Apr.1	0.0%			$ (0.006)
Rate 22B: Columbia except Elkview - Firm MTQ	0.4%	$ (69)	4,845.6	$ (0.014)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Apr. 1 to Nov. 1	0.0%			$ (0.014)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Nov. 1 to Apr.1	0.0%			$ (0.014)
Total of Rate 22	4.3%	$ (655)	29,680.7	
Grand Total	100.0%	$ (15,378)	169,539.6	

Second, the Phase-In Rate Rider must be adjusted to recover the costs of amalgamation and the balance in the Amalgamation Regulatory account, which is approved for recovery over three years. The Amalgamation Regulatory Account includes a revised forecast amount of approximately $1.8 million of amalgamation costs plus interest, with a projected 2017 after-tax opening balance in this account of $0.578 million. The difference between the actual and projected 2016 and 2017 recoveries will be returned to or recovered from customers in a future application.

Table 10-10 below shows the 2017 opening balance grossed up to a pre-tax amount plus 2017 interest for a total 2017 required recovery of $0.792 million. Dividing the $0.792 million by 2017 forecast volume for Vancouver Island and Whistler of 13,345.0 TJ produces an Amalgamation Cost Component of the Vancouver Island and Whistler Phase-In Riders of $0.059 per GJ.

Table 10-10: Amalgamation Cost Component of Phase-In Rider ($000s)

Amalgamation Cost Component of Phase-In Rider ($000 unless otherwise stated)		
2016 Opening Balance Amalgamation Regulatory Account after-tax	$	1,109.0
2016 Projected Interest Costs		10.0
2016 Projected Recovery		(730.7)
Less: Taxes		190.0
2017 Opening Balance Amalgamation Regulatory Account after-tax	$	578.3
2017 Projected Interest Costs		8.1
2017 Amalgamation Regulatory Account after-tax amount to be recovered	$	586.3
Tax Rate		26%
2017 Amalgamation Regulatory Account pre-tax amount to be recovered	$	792.3
2016 Forecast Volume for Vancouver Island and Whistler (TJ)		13,345.0
2016 Amalgamation Cost Component of Phase-In Rider ($/GJ)	$	0.059

Finally, to determine the 2017 Phase-in rider for Vancouver Island and Whistler customers, the amounts from Table 10-8 above need to be increased by the revised Amalgamation Cost Component calculated in Table 10-10. The table below shows the Phase-in Riders including this amount.

Table 10-11: Phase-in Rate Rider Calculation for Vancouver Island and Whistler Customers including Amalgamation Costs

	Phase In Rate Rider ($/GJ)	Amalgamation Cost Component of Phase-In Rider ($/GJ)	Total Rider ($/GJ)	Volume (TJ)	Total ($ thousand)
FEVI RS1/1B	$ 0.824	$ 0.059	$ 0.883	5,414.2	$ 4,783
FEW RS1/1B	$ 1.573	$ 0.059	$ 1.632	257.3	$ 420
FEVI RS2/2B	$ 0.938	$ 0.059	$ 0.997	3,114.4	$ 3,106
FEW RS2/2B	$ 1.734	$ 0.059	$ 1.793	243.1	$ 436
FEVI RS3/3B/23	$ 0.348	$ 0.059	$ 0.407	2,764.9	$ 1,126
FEW RS3/3B/23	$ 0.923	$ 0.059	$ 0.982	321.8	$ 316
FEVI RS4 (off-peak)*	$ 0.348	$ 0.059	$ 0.407		
FEVI RS4 (extension)*	$ 0.348	$ 0.059	$ 0.407		
FEW RS4 (off-peak)*	$ 0.923	$ 0.059	$ 0.982		
FEW RS4 (extension)*	$ 0.923	$ 0.059	$ 0.982		
FEVI RS5/5B/25	$ 1.259	$ 0.059	$ 1.318	1,029.8	$ 1,358
FEW RS5/5B/25	$ 0.923	$ 0.059	$ 0.982	44.6	$ 44
FEVI RS6/26*	$ 0.348	$ 0.059	$ 0.407		
FEW RS6/26*	$ 0.923	$ 0.059	$ 0.982		
FEVI RS7/27	$ 0.348	$ 0.059	$ 0.407	154.9	$ 63
FEW RS7/27*	$ 0.923	$ 0.059	$ 0.982		
FEVI R22*	$ 0.348	$ 0.059	$ 0.407		
FEW R22*	$ 0.923	$ 0.059	$ 0.982		
Total				13,345.0	$ 11,652

**There are no 2017 forecasted volumes for these rate classes, therefore rate riders from FEVI and FEW Rate Schedule 3 have been assigned.*

The difference between the actual and projected 2016 or 2017 forecasted amounts are captured in the phase-in rider deferral account will be returned to or recovered from customers in a future application.

10.2.3 RSAM Rate Riders

The RSAM Rate Riders collect one-half of the previous year's projected RSAM balance from Rate Schedule 1, 2, 3, and 23 customers. The projected balance in the RSAM account at the end of 2016 is a debit of $47.6 million. The calculation of the 2017 RSAM riders is shown in Table 10-12.

Table 10-12: 2017 RSAM Riders

2016 RSAM + Interest Closing Balance ($000)	47,588
Amortization Period (years)	2
2017 Amortization post-tax ($000)	23,794
Tax Rate	26%
2017 Amortization pre-tax ($000)	32,154

RSAM (Rider 5) Calculation			
Rate Class	RSAM Amortization ($000)	2017 Volume (TJ)	Rider ($/GJ)
Rate 1/1B/1U/1X		74,279.4	0.246
Rate 2/2B/2U/2X		28,522.9	0.246
Rate 3/3B/3U/3X		18,620.8	0.246
Rate 23		9,175.6	0.246
	32,154	130,598.7	0.246

The differences that result from the actual 2016 ending RSAM balance varying from the projection, and the actual 2017 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2018 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 2017 in compliance with the approved mechanism, including an estimate for 2016 which includes an adjustment for capital exceeding the dead band, a true-up for 2015, and an adjustment for the impact of actual customer additions on growth capital. In addition, FEI has updated all of the 2017 delivery rate riders for 2016 projected ending balances and 2017 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 Schedule 1

FOR THE YEAR ENDING DECEMBER 31, 2017

($millions)

Line No.	Particulars	2017 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (20.376)		
3	Change in Other Revenue	(1.104)	(21.480)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	(0.076)		
7	Capitalized Overhead Change	0.014	(0.062)	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation Rate Change (Depr Study)	(7.566)		
11	Depreciation from Net Additions	17.684	10.118	
12				
13	**AMORTIZATION EXPENSE**			
14	CIAC Rate Change (Depr Study)	1.859		
15	CIAC from Net Additions	0.127		
16	Net Salvage Rate Change (Depr Study)	11.170		
17	Deferrals	(8.668)	4.488	
18				
19	**FINANCING AND RETURN ON EQUITY**			
20	Financing Rate Changes	(13.597)		
21	Financing Ratio Changes	(4.909)		
22	Rate Base Growth	30.340	11.834	
23				
24	**TAX EXPENSE**			
25	Property and Other Taxes	4.414		
26	Other Income Taxes Changes	0.007	4.421	
27				
28				
29	Revenue Deficiency (Surplus)		$ 9.319	Schedule 16, Line 11, Column 4
30				
31	Margin @ Existing Rates		780.199	Schedule 16, Line 15, Column 3
32	Rate Change		1.19%	

UTILITY RATE BASE Schedule 2
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 5,517,286	$ 5,666,380	$ 149,094	Schedule 6.2, Line 38, Column 3
2	Opening Balance Adjustment	-	6,388	6,388	
3	Net Additions	152,567	592,158	439,591	Schedule 6.2, Line 38, Column 5+6+7
4	Plant in Service, Ending	5,669,853	6,264,926	595,073	
5					
6	Accumulated Depreciation Beginning	$ (1,691,556)	$ (1,808,620)	$ (117,064)	Schedule 7.2, Line 38, Column 5
7	Net Additions	(119,574)	(134,885)	(15,311)	Schedule 7.2, Line 38, Column 7+8
8	Accumulated Depreciation Ending	(1,811,130)	(1,943,505)	(132,375)	
9					
10	CIAC, Beginning	$ (425,250)	$ (424,231)	$ 1,019	Schedule 9, Line 7, Column 2
11	Opening Balance Adjustment	-	(270)	(270)	
12	Net Additions	1,022	(3,660)	(4,682)	Schedule 9, Line 7, Column 5+6
13	CIAC, Ending	(424,228)	(428,161)	(3,933)	
14					
15	Accumulated Amortization Beginning - CIAC	$ 139,013	$ 147,462	$ 8,449	Schedule 9, Line 15, Column 2
16	Net Additions	8,447	6,071	(2,376)	Schedule 9, Line 15, Column 5+6
17	Accumulated Amortization Ending - CIAC	147,460	153,533	6,073	
18					
19	Net Plant in Service, Mid-Year	$ 3,560,724	$ 3,816,951	$ 256,227	
20					
21	Adjustment for timing of Capital additions	$ 3,685	$ 221,936	$ 218,251	
22	Capital Work in Progress, No AFUDC	35,156	30,435	(4,721)	
23	Unamortized Deferred Charges	32,735	22,249	(10,486)	Schedule 11.1, Line 32, Column 10
24	Working Capital	61,048	49,624	(11,424)	Schedule 13, Line 14, Column 3
25	Deferred Income Taxes Regulatory Asset	388,446	407,048	18,602	Schedule 15, Line 6, Column 3
26	Deferred Income Taxes Regulatory Liability	(388,446)	(407,048)	(18,602)	Schedule 15, Line 6, Column 3
27	LILO Benefit	(651)	(485)	166	
28					
29	Mid-Year Utility Rate Base	$ 3,692,697	$ 4,140,710	$ 448,013	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Reference	2014	2015	2016	2017	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Formula Cost Drivers**						
2	CPI		0.473%	0.879%	0.980%	1.627%	
3	AWE		2.277%	1.646%	2.050%	1.212%	
4	Labour Split						
5	Non Labour		45.000%	45.000%	45.000%	45.000%	
6	Labour		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%	1.399%	
8	Productivity Factor		-1.100%	-1.100%	-1.100%	-1.100%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.360%	0.201%	0.469%	0.299%	
10							
11	Average Customer Growth		0.260%	0.614%	0.567%	0.675%	
12	Inflation Factor for Base Capital	(1 + Line 9) x (1 + Line 11)	100.621%	100.816%	101.039%	100.976%	
13							
14	Customer Growth Factor		-0.688%	-5.615%	16.249%	0.324%	
15	Inflation Factor for Growth Capital	(1 + Line 9) x (1 + Line 14)	99.669%	94.575%	116.794%	100.624%	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2017
($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	100.624%	100.976%			Schedule 3, Line 12 & 15, Column 6
21	Formula Capex	$ 33,470	$ 113,080		$ 146,550	
22						
23	**Capital Tracked Outside of Formula**					
24	Pension & OPEB (Capital Portion)			$ 2,663		
25	Biomethane Interconnect			1,952		
26	NGT Assets			2,995		
27	Total			$ 7,610	7,610	
28						
29	**Total Capital Expenditures Net of CIAC**				$ 154,160	
30						
31	Contributions in Aid of Construction				6,578	
32	**Total Additions to Plant**				$ 160,738	
33						
34	Notes					
35	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 Schedule 5
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars (1)	2017 Formula (2)	Cross Reference (3)
1	**CAPEX**		
2			
3	Growth Capital Expenditures	$ 33,470	Schedule 4, Line 21, Column 2
4	Sustainment Capital Expenditures	113,080	Schedule 4, Line 21, Column 3
5	Forecast Capital Expenditures	7,610	Schedule 4, Line 27, Column 4
6	CIAC	6,578	Schedule 4, Line 31, Column 5
7	Total Capital Expenditures	$ 160,738	
8			
9	**Special Projects and CPCN's**		
10			
11	LMIPSU	$ 21,309	
12	CTS	130,295	
13	Tilbury Expansion	12,432	
14	Total Capital Expenditures	$ 164,036	
15			
16	**Total Capital Expenditures**	$ 324,774	
17			
18			
19	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**		
20			
21	Regular Capital Expenditures	$ 160,738	
22	Add - Capitalized Overheads	32,580	Schedule 20, Line 35, Column 4
23	Add - AFUDC	2,282	
24	Gross Capital Expenditures	195,600	
25	Change in Work in Progress	-	
26	**Total Regular Additions to Plant**	$ 195,600	
27			
28	Special Projects and CPCN's Capital Expenditures	$ 164,036	
29	Add - AFUDC	6,887	
30	Gross Capital Expenditures	170,923	
31	Change in Work in Progress	272,949	
32	**Total Special Projects and CPCN Additions to Plant**	$ 443,872	
33			
34	**Grand Total Additions to Plant**	$ 639,472	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	12/31/2016	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2017	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	117-00	Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	
3	175-10	Unamortized Conversion Expense	109	-	-	-	-	109	
4	175-00	Unamortized Conversion Expense - Squamish	777	-	-	-	-	777	
5	178-00	Organization Expense	728	-	-	-	-	728	
6	179-01	Other Deferred Charges	-	-	-	-	-	-	
7	401-01	Franchise and Consents	297	-	-	-	-	297	
8	402-11	Utility Plant Acquisition Adjustment	62	-	-	-	-	62	
9	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
10	431-01	Mfg'd Gas Land Rights	-	-	-	-	-	-	
11	461-01	Transmission Land Rights	53,992	19	-	494	-	54,505	
12	461-02	Transmission Land Rights - Mt. Hayes	610	-	-	-	-	610	
13	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
14	461-13	IP Land Rights Whistler	87	-	-	-	-	87	
15	471-01	Distribution Land Rights	3,079	-	-	-	-	3,079	
16	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
17	402-01	Application Software - 12.5%	104,490	285	-	7,154	(2,134)	109,795	
18	402-02	Application Software - 20%	28,160	251	-	6,166	(6,161)	28,416	
19			$ 194,315	$ 555	$ -	$ 13,814	$ (8,295)	$ 200,389	
20									
21		**MANUFACTURED GAS / LOCAL STORAGE**							
22	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
23	431-00	Manufact'd Gas - Land Rights	-	-	-	-	-	-	
24	432-00	Manufact'd Gas - Struct. & Improvements	998	-	-	-	-	998	
25	433-00	Manufact'd Gas - Equipment	1,449	10	-	354	-	1,813	
26	434-00	Manufact'd Gas - Gas Holders	2,940	-	-	-	-	2,940	
27	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
28	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	-	-	-	-	875	
29	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
30	442-00	Structures & Improvements (Tilbury)	4,959	-	90,602	-	-	95,561	
31	443-00	Gas Holders - Storage (Tilbury)	16,499	-	64,716	-	-	81,215	
32	448-11	Piping (Tilbury)	-	-	56,087	-	-	56,087	
33	448-21	Pre-treatment (Tilbury)	-	-	43,144	-	-	43,144	
34	448-31	Liquefaction Equipment (Tilbury)	-	-	116,490	-	-	116,490	
35	449-00	Local Storage Equipment (Tilbury)	32,270	76	12,432	2,517	(20)	47,275	
36	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
37	442-01	Structures & Improvements (Mount Hayes)	17,310	-	-	-	-	17,310	
38	443-05	Gas Holders - Storage (Mount Hayes)	60,112	-	-	-	-	60,112	
39	448-41	Send out Equipment(Tilbury)	-	-	4,314	-	-	4,314	
40	448-51	Sub-station and Electric (Tilbury)	-	-	38,830	-	-	38,830	
41	448-61	Control Room (Tilbury)	-	-	12,943	-	-	12,943	
42	448-10	Piping (Mount Hayes)	11,488	-	-	-	-	11,488	
43	448-20	Pre-treatment (Mount Hayes)	28,714	-	-	-	-	28,714	
44	448-30	Liquefaction Equipment (Mount Hayes)	28,714	-	-	-	-	28,714	
45	448-40	Send out Equipment (Mount Hayes)	22,960	-	-	-	-	22,960	
46	448-50	Sub-station and Electric (Mount Hayes)	21,644	-	-	-	-	21,644	
47	448-60	Control Room (Mount Hayes)	5,900	-	-	-	-	5,900	
48	449-01	Local Storage Equipment (Mount Hayes)	6,363	-	-	-	-	6,363	
49			$ 279,840	$ 86	$ 439,558	$ 2,871	$ (20)	$ 722,335	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2016	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2017	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	14,019	-	-	-	-	14,019	
6	464-00	Other Structures & Improvements	6,485	-	-	-	-	6,485	
7	465-00	Mains	1,182,225	452	-	15,091	(1,343)	1,196,425	
8	465-20	Mains - INSPECTION	17,811	78	-	2,660	(1,026)	19,523	
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	181,052	86	-	2,921	(722)	183,337	
13	466-10	Compressor Equipment - OVERHAUL	3,856	-	-	-	-	3,856	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,342	-	-	-	-	5,342	
15	467-10	Measuring & Regulating Equipment	54,759	-	4,314	-	-	59,073	
16	467-20	Telemetering	14,222	11	-	351	(7)	14,577	
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	4,245	-	-	-	-	4,245	
20			$ 1,574,041	$ 627	$ 4,314	$ 21,023	$ (3,098)	$ 1,596,907	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 4,207	$ -	$ -	$ -	$ -	$ 4,207	
24	471-00	Distribution Land Rights	-	-	-	-	-	-	
25	472-00	Structures & Improvements	21,577	-	-	-	-	21,577	
26	472-10	Structures & Improvements - Byron Creek	107	-	-	-	-	107	
27	473-00	Services	1,105,786	1,404	-	45,137	(4,333)	1,147,994	
28	474-00	House Regulators & Meter Installations	195,662	-	-	-	(7,436)	188,226	
29	474-02	Meters/Regulators Installations	126,634	845	-	27,193	-	154,672	
30	475-00	Mains	1,366,144	928	-	29,996	(1,775)	1,395,293	
31	476-00	Compressor Equipment	1,110	-	-	-	-	1,110	
32	477-10	Measuring & Regulating Equipment	130,708	283	-	9,612	(547)	140,056	
33	477-20	Telemetering	11,511	32	-	1,064	(61)	12,546	
34	477-30	Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	163	
35	478-10	Meters	243,817	568	-	13,865	(7,134)	251,116	
36	478-20	Instruments	11,944	-	-	-	-	11,944	
37	479-00	Other Distribution Equipment	-	-	-	-	-	-	
38			$ 3,219,370	$ 4,060	$ -	$ 126,867	$ (21,286)	$ 3,329,011	
39									
40		**BIO GAS**							
41	472-00	Bio Gas Struct. & Improvements	$ 688	$ -	$ -	$ 216	$ -	$ 904	
42	475-10	Bio Gas Mains – Municipal Land	1,721	-	-	377	-	2,098	
43	475-20	Bio Gas Mains – Private Land	55	-	-	-	-	55	
44	418-10	Bio Gas Purification Overhaul	20	-	-	-	-	20	
45	418-20	Bio Gas Purification Upgrader	8,075	-	-	-	-	8,075	
46	477-40	Bio Gas Reg & Meter Equipment	2,214	-	-	1,393	-	3,607	
47	478-30	Bio Gas Meters	38	-	-	22	-	60	
48	474-10	Bio Gas Reg & Meter Installations	245	-	-	-	-	245	
49			$ 13,056	$ -	$ -	$ 2,008	$ -	$ 15,064	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	12/31/2016	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2017	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 10,315	$ -	$ -	$ 2,062	$ -	$ 12,377	
3	476-20	NG Transportation LNG Dispensing Equipment	4,578	-	-	-	-	4,578	
4	476-30	NG Transportation CNG Foundations	1,402	-	-	100	-	1,502	
5	476-40	NG Transportation LNG Foundations	1,334	-	-	-	-	1,334	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,591	-	-	-	-	1,591	
7	476-60	NG Transportation CNG Dehydrator	335	-	-	-	-	335	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 19,555	$ -	$ -	$ 2,162	$ -	$ 21,717	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 30,467	$ 16	$ -	$ 385	$ -	$ 30,868	
13	481-00	Land Rights	-	-	-	-	-	-	
14	482-10	Frame Buildings	16,822	-	-	-	-	16,822	
15	482-20	Masonry Buildings	124,576	245	-	5,987	(153)	130,655	
16	482-30	Leasehold Improvement	4,779	8	-	198	(28)	4,957	
17	483-30	GP Office Equipment	4,740	24	-	578	(285)	5,057	
18	483-40	GP Furniture	22,029	79	-	1,937	(1,273)	22,772	
19	483-10	GP Computer Hardware	47,377	387	-	9,531	(8,229)	49,066	
20	483-20	GP Computer Software	3,788	-	-	-	-	3,788	
21	483-21	GP Computer Software	-	-	-	-	-	-	
22	483-22	GP Computer Software	-	-	-	-	-	-	
23	484-00	Vehicles	14,643	110	-	2,684	-	17,437	
24	484-10	Vehicles - Leased	26,123	-	-	-	(1,410)	24,713	
25	485-10	Heavy Work Equipment	858	-	-	-	-	858	
26	485-20	Heavy Mobile Equipment	5,857	-	-	870	-	6,727	
27	486-00	Small Tools & Equipment	50,696	141	-	3,428	(2,599)	51,666	
28	487-20	Equipment on Customer's Premises	24	-	-	-	-	24	
29	488-10	Telephone	3,898	-	-	-	(542)	3,356	
30	488-20	Radio	9,526	50	-	1,257	(96)	10,737	
31	489-00	Other General Equipment	-	-	-	-	-	-	
32			$ 366,203	$ 1,060	$ -	$ 26,855	$ (14,615)	$ 379,503	
33									
34		**UNCLASSIFIED PLANT**							
35	499-00	Plant Suspense	-	-	-	-	-	-	
36			$ -	$ -	$ -	$ -	$ -	$ -	
37									
38		**Total Plant in Service**	$ 5,666,380	$ 6,388	$ 443,872	$ 195,600	$ (47,314)	$ 6,264,926	
39									
40		Cross Reference			Schedule 5, Line 32, Column 2	Schedule 5, Line 26, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2016	1/1/2017 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2017	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	117-00	Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	175-10	Unamortized Conversion Expense	109	1.00%	59	-	1	-	-	-	60	
4	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	735	-	42	-	-	-	777	
5	178-00	Organization Expense	728	1.00%	421	-	7	-	-	-	428	
6	179-01	Other Deferred Charges	-	0.00%	-	-	-	-	-	-	-	
7	401-01	Franchise and Consents	297	5.39%	194	-	11	-	-	-	205	
8	402-11	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	-	62	
9	402-03	Other Intangible Plant	1,907	2.01%	1,031	-	38	-	-	-	1,069	
10	431-01	Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-	-	-	
11	461-01	Transmission Land Rights	54,011	0.00%	1,766	-	-	-	-	-	1,766	
12	461-02	Transmission Land Rights - Mt. Hayes	610	0.00%	-	-	-	-	-	-	-	
13	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
14	461-13	IP Land Rights Whistler	87	0.00%	10	-	-	-	-	-	10	
15	471-01	Distribution Land Rights	3,079	0.00%	238	-	-	-	-	-	238	
16	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
17	402-01	Application Software - 12.5%	104,775	12.50%	54,838	-	13,097	(2,134)	-	-	65,801	
18	402-02	Application Software - 20%	28,411	20.00%	12,258	-	5,682	(6,161)	-	-	11,779	
19			$ 194,870		$ 71,632	$ -	$ 18,878	$ (8,295)	$ -	$ -	$ 82,215	
20												
21		**MANUFACTURED GAS / LOCAL STORAGE**										
22	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
23	431-00	Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-	-	-	
24	432-00	Manufact'd Gas - Struct. & Improvements	998	2.82%	288	-	28	-	-	-	316	
25	433-00	Manufact'd Gas - Equipment	1,459	4.66%	270	-	68	-	-	-	338	
26	434-00	Manufact'd Gas - Gas Holders	2,940	2.45%	512	-	72	-	-	-	584	
27	436-00	Manufact'd Gas - Compressor Equipment	367	3.68%	113	-	13	-	-	-	126	
28	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	2.34%	907	-	20	-	-	-	927	
29	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
30	442-00	Structures & Improvements (Tilbury)	95,561	3.03%	3,497	-	2,896	-	-	-	6,393	
31	443-00	Gas Holders - Storage (Tilbury)	81,215	1.88%	11,995	-	1,527	-	-	-	13,522	
32	448-11	Piping (Tilbury)	56,087	2.46%	-	-	1,380	-	-	-	1,380	
33	448-21	Pre-treatment (Tilbury)	43,144	3.88%	-	-	1,674	-	-	-	1,674	
34	448-31	Liquefaction Equipment (Tilbury)	116,490	2.46%	-	-	2,866	-	-	-	2,866	
35	449-00	Local Storage Equipment (Tilbury)	44,778	3.83%	15,423	-	1,712	(20)	-	-	17,115	
36	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
37	442-01	Structures & Improvements (Mount Hayes)	17,310	3.88%	3,859	-	672	-	-	-	4,531	
38	443-05	Gas Holders - Storage (Mount Hayes)	60,112	1.65%	5,603	-	992	-	-	-	6,595	
39	448-41	Send out Equipment(Tilbury)	4,314	2.44%	-	-	105	-	-	-	105	
40	448-51	Sub-station and Electric (Tilbury)	38,830	2.44%	-	-	947	-	-	-	947	
41	448-61	Control Room (Tilbury)	12,943	6.30%	-	-	815	-	-	-	815	
42	448-10	Piping (Mount Hayes)	11,488	2.46%	1,603	-	283	-	-	-	1,886	
43	448-20	Pre-treatment (Mount Hayes)	28,714	3.88%	6,411	-	1,114	-	-	-	7,525	
44	448-30	Liquefaction Equipment (Mount Hayes)	28,714	2.46%	4,007	-	706	-	-	-	4,713	
45	448-40	Send out Equipment (Mount Hayes)	22,960	2.44%	3,204	-	560	-	-	-	3,764	
46	448-50	Sub-station and Electric (Mount Hayes)	21,644	2.44%	3,020	-	528	-	-	-	3,548	
47	448-60	Control Room (Mount Hayes)	5,900	6.30%	2,198	-	372	-	-	-	2,570	
48	449-01	Local Storage Equipment (Mount Hayes)	6,363	2.86%	199	-	182	-	-	-	381	
49			$ 719,484		$ 63,110	$ -	$ 19,532	$ (20)	$ -	$ -	$ 82,622	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2016	1/1/2017 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2017	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%	15,611	-	1,035	-	-	-	16,646	
5	463-00	Measuring Structures	14,019	2.29%	6,770	-	321	-	-	-	7,091	
6	464-00	Other Structures & Improvements	6,485	3.66%	2,646	-	237	-	-	-	2,883	
7	465-00	Mains	1,182,677	1.47%	377,566	-	17,379	(1,343)	-	-	393,602	
8	465-20	Mains - INSPECTION	17,889	15.20%	8,039	-	2,707	(1,026)	-	-	9,720	
9	465-11	IP Transmission Pipeline - Whistler	42,288	1.53%	4,488	-	647	-	-	-	5,135	
10	465-30	Mt Hayes - Mains	6,299	1.51%	598	-	95	-	-	-	693	
11	465-10	Mains - Byron Creek	974	5.03%	1,182	-	49	-	-	-	1,231	
12	466-00	Compressor Equipment	181,138	2.89%	82,716	-	5,232	(722)	-	-	87,226	
13	466-10	Compressor Equipment - OVERHAUL	3,856	10.19%	2,663	-	393	-	-	-	3,056	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,342	2.58%	1,176	-	138	-	-	-	1,314	
15	467-10	Measuring & Regulating Equipment	59,073	2.41%	23,718	-	1,424	-	-	-	25,142	
16	467-20	Telemetering	14,233	9.75%	6,633	-	1,387	(7)	-	-	8,013	
17	467-31	IP Intermediate Pressure Whistler	313	2.55%	89	-	8	-	-	-	97	
18	467-30	Measuring & Regulating Equipment - Byron Creek	39	2.41%	10	-	1	-	-	-	11	
19	468-00	Communication Structures & Equipment	4,245	0.56%	4,807	-	24	-	-	-	4,831	
20			$ 1,578,982		$ 539,215	$ -	$ 31,077	$ (3,098)	$ -	$ -	$ 567,194	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 4,207	0.00%	$ (9)	$ -	$ -	$ -	$ -	$ -	$ (9)	
24	471-00	Distribution Land Rights	-	0.00%	-	-	-	-	-	-	-	
25	472-00	Structures & Improvements	21,577	2.41%	8,686	-	520	-	-	-	9,206	
26	472-10	Structures & Improvements - Byron Creek	107	4.67%	53	-	5	-	-	-	58	
27	473-00	Services	1,107,190	2.45%	266,905	-	27,091	(4,333)	-	-	289,663	
28	474-00	House Regulators & Meter Installations	195,662	5.99%	78,041	-	11,721	(7,436)	-	-	82,326	
29	474-02	Meters/Regulators Installations	127,479	4.55%	11,474	-	5,759	-	-	-	17,233	
30	475-00	Mains	1,367,072	1.54%	455,212	-	21,038	(1,775)	-	-	474,475	
31	476-00	Compressor Equipment	1,110	0.00%	1,269	-	-	-	-	-	1,269	
32	477-10	Measuring & Regulating Equipment	130,991	3.05%	48,267	-	3,987	(547)	-	-	51,707	
33	477-20	Telemetering	11,543	2.82%	6,069	-	325	(61)	-	-	6,333	
34	477-30	Measuring & Regulating Equipment - Byron Creek	163	0.00%	216	-	-	-	-	-	216	
35	478-10	Meters	244,385	7.09%	124,538	-	17,287	(7,134)	-	-	134,691	
36	478-20	Instruments	11,944	2.99%	2,803	-	357	-	-	-	3,160	
37	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
38			$ 3,223,430		$ 1,003,524	$ -	$ 88,090	$ (21,286)	$ -	$ -	$ 1,070,328	
39												
40		**BIO GAS**										
41	472-00	Bio Gas Struct. & Improvements	$ 688	2.72%	$ 55	$ -	$ 19	$ -	$ -	$ -	$ 74	
42	475-10	Bio Gas Mains – Municipal Land	1,721	1.55%	44	-	27	-	-	-	71	
43	475-20	Bio Gas Mains – Private Land	55	1.55%	4	-	1	-	-	-	5	
44	418-10	Bio Gas Purification Overhaul	20	5.00%	3	-	1	-	-	-	4	
45	418-20	Bio Gas Purification Upgrader	8,075	4.89%	973	-	395	-	-	-	1,368	
46	477-40	Bio Gas Reg & Meter Equipment	2,214	3.24%	222	-	72	-	-	-	294	
47	478-30	Bio Gas Meters	38	5.02%	7	-	2	-	-	-	9	
48	474-10	Bio Gas Reg & Meter Installations	245	5.24%	17	-	13	-	-	-	30	
49			$ 13,056		$ 1,325	$ -	$ 530	$ -	$ -	$ -	$ 1,855	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.2
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2016	1/1/2017 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2017	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	10,315	5.00%	$ 1,329	-	516	-	-	-	$ 1,845	
3	476-20	NG Transportation LNG Dispensing Equipment	4,578	5.00%	643	-	229	-	-	-	872	
4	476-30	NG Transportation CNG Foundations	1,402	5.00%	188	-	70	-	-	-	258	
5	476-40	NG Transportation LNG Foundations	1,334	5.00%	165	-	67	-	-	-	232	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,591	10.00%	169	-	159	-	-	-	328	
7	476-60	NG Transportation CNG Dehydrator	335	5.00%	53	-	17	-	-	-	70	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 19,555		$ 2,547	$ -	$ 1,058	$ -	$ -	$ -	$ 3,605	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 30,483	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	481-00	Land Rights	-	0.00%	-	-	-	-	-	-	-	
14	482-10	Frame Buildings	16,822	6.04%	7,749	-	1,016	-	-	-	8,765	
15	482-20	Masonry Buildings	124,821	1.95%	25,648	-	2,434	(153)	-	-	27,929	
16	482-30	Leasehold Improvement	4,787	9.49%	2,039	-	454	(28)	-	-	2,465	
17	483-30	GP Office Equipment	4,764	6.67%	3,686	-	318	(285)	-	-	3,719	
18	483-40	GP Furniture	22,108	5.00%	8,111	-	1,105	(1,273)	-	-	7,943	
19	483-10	GP Computer Hardware	47,764	20.00%	20,918	-	9,553	(8,229)	-	-	22,242	
20	483-20	GP Computer Software	3,788	12.50%	2,235	-	473	-	-	-	2,708	
21	483-21	GP Computer Software	-	0.00%	-	-	-	-	-	-	-	
22	483-22	GP Computer Software	-	0.00%	-	-	-	-	-	-	-	
23	484-00	Vehicles	14,753	10.55%	6,720	-	1,556	-	-	-	8,276	
24	484-10	Vehicles - Leased	26,123	9.44%	20,802	-	2,050	(1,410)	-	-	21,442	
25	485-10	Heavy Work Equipment	858	6.38%	508	-	55	-	-	-	563	
26	485-20	Heavy Mobile Equipment	5,857	9.85%	2,465	-	577	-	-	-	3,042	
27	486-00	Small Tools & Equipment	50,837	5.00%	21,563	-	2,542	(2,599)	-	-	21,506	
28	487-20	Equipment on Customer's Premises	24	6.67%	19	-	2	-	-	-	21	
29	488-10	Telephone	3,898	6.67%	2,294	-	260	(542)	-	-	2,012	
30	488-20	Radio	9,576	6.67%	2,493	-	639	(96)	-	-	3,036	
31	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
32			$ 367,263		$ 127,267	$ -	$ 23,034	$ (14,615)	$ -	$ -	$ 135,686	
33												
34		**UNCLASSIFIED PLANT**										
35	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
36			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
37												
38		**Total**	$ 6,116,640		$ 1,808,620	$ -	$ 182,199	$ (47,314)	$ -	$ -	$ 1,943,505	
39		Less: Depreciation & Amortization Transferred to Biomethane BVA					(399)					
40		Less: Vehicle Depreciation Allocated To Capital Projects					(1,334)					
41		**Net Depreciation Expense**					$ 180,466					
42												
43		Cross Reference	Schedule 6.2, Line 38, Column 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars			12/31/2016	1/1/2017 Opening Adjt	CPCN's	Additions	Retirements	12/31/2017	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	Mobile Refueling Station			1,357	(70)	-	-	-	1,287	
5									-	
6	**Total**			$ 179,005	$ (70)	$ -	$ -	$ -	$ 178,935	
7										
8										
9										

10 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
11 **FOR THE YEAR ENDING DECEMBER 31, 2017**
12 **($000s)**
13
14

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2016	1/1/2017 Opening Adjt	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2017	Cross Reference
17	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
18										
19	**Non-Regulated Plant Depreciation**									
20	NRB Depreciation @ 0%	$ 1,054	0.00%	$ 582	$ -	$ -	$ -	$ -	$ 582	
21	NRB Depreciation @ 2.4%	176,594	2.40%	117,223	-	4,238	-	-	121,461	
22	Mobile Refueling Station	1,357	5.00%	132	-	50	-	-	182	
23									-	
24	**Total**	$ 179,005		$ 117,937	$ -	$ 4,288	$ -	$ -	$ 122,225	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 9

Line No.	Particulars	12/31/2016	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2017	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 274,845	$ 251	$ -	$ 6,115	$ -	$ 281,211	
3	Transmission Contributions	145,585	19	-	463	-	146,067	
4	Others	722	-	-	-	-	722	
5	Software Tax Savings - Infrastructure/Custom	2,533	-	-	-	(2,918)	(385)	
6	Biomethane	546	-	-	-	-	546	
7	**Total**	$ 424,231	$ 270	$ -	$ 6,578	$ (2,918)	$ 428,161	
8								
9	**Amortization**							
10	Distribution Contributions	$ (96,372)	$ -	$ -	$ (6,382)	$ -	$ (102,754)	
11	Transmission Contributions	(48,033)	-	-	(2,155)	-	(50,188)	
12	Others	(608)	-	-	(108)	-	(716)	
13	Software Tax Savings - Infrastructure/Custom	(2,319)	-	-	(317)	2,918	282	
14	Biomethane	(130)	-	-	(27)	-	(157)	
15	**Total**	$ (147,462)	$ -	$ -	$ (8,989)	$ 2,918	$ (153,533)	
16								
17	**Net CIAC**	$ 276,769	$ 270	$ -	$ (2,411)	$ -	$ 274,628	
18								
19								
20	Total CIAC Amortization Expense per Line 15				$ (8,989)			
21	Less: CIAC Amortization Transferred to Biomethane BVA				27			
22	**Net CIAC Amortization Expense**				$ (8,962)			

FORTISBC ENERGY INC. August 2, 2016 Section 11

NET SALVAGE CONTINUITY SCHEDULE Schedule 10
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2016	Net Salv Provision	Retirement Costs / 12/31/2017	12/31/2017	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)	95,561	0.36%	89	344	-	433	
4	443-00	Gas Holders - Storage (Tilbury)	81,215	0.45%	330	365	-	695	
5	448-11	Piping (Tilbury)	56,087	0.27%	-	151	-	151	
6	448-21	Pre-treatment (Tilbury)	43,144	0.46%	-	198	-	198	
7	448-31	Liquefaction Equipment (Tilbury)	116,490	0.54%	-	629	-	629	
8	449-00	Local Storage Equipment (Tilbury)	44,778	0.39%	484	174	-	658	
9	442-01	Structures & Improvements (Mount Hayes)	17,310	0.45%	-	78	-	78	
10	443-05	Gas Holders - Storage (Mount Hayes)	60,112	0.35%	-	210	-	210	
11	448-41	Send out Equipment(Tilbury)	4,314	0.27%	-	12	-	12	
12	448-51	Sub-station and Electric (Tilbury)	38,830	0.54%	-	210	-	210	
13	448-10	Piping (Mount Hayes)	11,488	0.27%	-	31	-	31	
14	448-20	Pre-treatment (Mount Hayes)	28,714	0.46%	-	132	-	132	
15	448-30	Liquefaction Equipment (Mount Hayes)	28,714	0.54%	-	155	-	155	
16	448-40	Send out Equipment (Mount Hayes)	22,960	0.27%	-	62	-	62	
17	448-50	Sub-station and Electric (Mount Hayes)	21,644	0.54%	-	117	-	117	
18	449-01	Local Storage Equipment (Mount Hayes)	6,363	0.28%	-	18	-	18	
19			$ 678,599		$ 903	$ 2,886	$ -	$ 3,789	
20									
21		**TRANSMISSION PLANT**							
22	462-00	Compressor Structures	$ 29,484	-0.02%	$ 466	$ (6)	$ -	$ 460	
23	463-00	Measuring Structures	14,019	0.57%	140	80	-	220	
24	464-00	Other Structures & Improvements	6,485	0.22%	30	14	-	44	
25	465-00	Mains	1,182,677	0.37%	9,306	4,374	-	13,680	
26	465-11	IP Transmission Pipeline - Whistler	42,288	0.34%	-	144	-	144	
27	465-30	Mt Hayes - Mains	6,299	0.32%	-	20	-	20	
28	466-00	Compressor Equipment	181,138	-0.12%	2,915	(217)	-	2,698	
29	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,342	0.21%	185	11	-	196	
30	467-10	Measuring & Regulating Equipment	59,073	0.22%	213	130	-	343	
31	467-31	IP Intermediate Pressure Whistler	313	0.22%	-	1	-	1	
32	468-00	Communication Structures & Equipment	4,245	-0.38%	446	(16)	-	430	
33			$ 1,531,363		$ 13,701	$ 4,535	$ -	$ 18,236	
34									
35		**DISTRIBUTION PLANT**							
36	472-00	Structures & Improvements	$ 21,577	0.32%	$ 187	$ 69	$ -	$ 256	
37	473-00	Services	1,107,190	1.61%	9,403	17,804	(9,119)	18,088	
38	474-00	House Regulators & Meter Installations	195,662	1.77%	(5,091)	3,463	(3,565)	(5,193)	
39	474-02	Meters/Regulators Installations	127,479	0.00%	1,595	-	-	1,595	
40	475-00	Mains	1,367,072	0.43%	19,106	5,875	(549)	24,432	
41	476-00	Compressor Equipment	1,110	0.00%	711	-	-	711	
42	477-10	Measuring & Regulating Equipment	130,991	0.46%	2,427	603	-	3,030	
43	477-20	Telemetering	11,543	0.42%	(12)	48	-	36	
44	478-10	Meters	244,385	-0.26%	4,442	(634)	-	3,808	
45			$ 3,207,009		$ 32,768	$ 27,228	$ (13,233)	$ 46,763	
46									
47		**BIO GAS**							
48	472-00	Bio Gas Struct. & Improvements	$ 688	0.29%	$ -	$ 2	$ -	$ 2	
49	475-10	Bio Gas Mains – Municipal Land	1,721	0.39%	11	7	-	18	
50	475-20	Bio Gas Mains – Private Land	55	0.39%	1	-	-	1	
51	418-20	Bio Gas Purification Upgrader	8,075	0.26%	-	21	-	21	
52	478-30	Bio Gas Meters	38	-0.21%	-	-	-	-	
53	474-10	Bio Gas Reg & Meter Installations	245	1.35%	-	3	-	3	
54			$ 10,822		$ 12	$ 33	$ -	$ 45	
55									
56		**GENERAL PLANT & EQUIPMENT**							
57	482-10	Frame Buildings	$ 16,822	0.00%	$ (12)	$ -	$ -	$ (12)	
58	482-20	Masonry Buildings	124,821	0.25%	(1)	312	-	311	
59	484-00	Vehicles	14,753	-1.00%	-	(148)	-	(148)	
60	485-10	Heavy Work Equipment	858	-0.68%	-	(6)	-	(6)	
61	485-20	Heavy Mobile Equipment	5,857	-2.89%	-	(169)	-	(169)	
62			$ 163,111		$ (13)	$ (11)	$ -	$ (24)	
63									
64		**Total**	$ 5,590,904		$ 47,371	$ 34,671	$ (13,233)	$ 68,809	
65		Less: Depreciation & Amortization Transferred to Biomethane BVA				(22)			
66		**Net Salvage Depreciation Expense**				$ 34,649			
67		Cross Reference	Schedule 6-6.2, Column 3+4+5						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	12/31/2016	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2017	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (25,572)	$ -	$ 34,556	$ (8,984)	$ -	$ -	$ -	$ -	$ (12,786)	
3	Midstream Cost Reconciliation Account (MCRA)	(17,267)	-	-	-	-	11,667	(3,033)	(8,633)	(12,950)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	47,205	-	-	-	-	(31,895)	8,293	23,603	35,404	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,322)	-	1,933	(503)	177	(259)	68	(2,906)	(3,614)	
6	Revelstoke Propane Cost Deferral Account	(115)	-	155	(40)	-	-	-	-	(58)	
7	SCP Mitigation Revenues Variance Account	(420)	-	-	-	355	-	-	(65)	(243)	
8		$ (491)	$ -	$ 36,644	$ (9,527)	$ 532	$ (20,487)	$ 5,328	$ 11,999	$ 5,753	
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	$ 74,154	$ 13,127	$ 15,000	$ (3,900)	$ (9,838)	$ -	$ -	$ 88,543	$ 87,912	
11	NGV Conversion Grants	62	-	10	(3)	(20)	-	-	49	56	
12	Emissions Regulations	(1,802)	-	-	-	360	-	-	(1,442)	(1,622)	
13	On-Bill Financing Pilot Program	13	-	(2)	-	-	-	-	11	12	
14	NGT Incentives	19,497	-	13,548	(3,522)	(2,558)	-	-	26,965	23,231	
15	CNG and LNG Recoveries	(415)	-	-	-	415	-	-	-	(208)	
16		$ 91,509	$ 13,127	$ 28,556	$ (7,425)	$ (11,641)	$ -	$ -	$ 114,126	$ 109,381	
17	Non-Controllable Items Deferral Accounts										
18	Pension & OPEB Variance	$ (6,939)	$ -	$ -	$ -	$ 2,919	$ -	$ -	$ (4,020)	$ (5,480)	
19	BCUC Levies Variance	517	-	-	-	(517)	-	-	-	259	
20	Customer Service Variance Account	(6,915)	-	-	-	3,457	-	-	(3,458)	(5,187)	
21	Pension & OPEB Funding	(186,204)	-	-	-	-	-	-	(186,204)	(186,204)	
22	US GAAP Pension & OPEB Funded Status	106,676	-	-	-	-	-	-	106,676	106,676	
23		$ (92,865)	$ -	$ -	$ -	$ 5,859	$ -	$ -	$ (87,006)	$ (89,936)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	12/31/2016	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2017	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2019 PBR Requirements	$ 735	$ -	$ -	$ -	$ (245)	$ -	$ -	$ 490	$ 613	
3	AES Inquiry Cost	122	-	-	-	(76)	-	-	46	84	
4	2016 Cost of Capital Application	1,258	-	-	-	(419)	-	-	839	1,049	
5	Amalgamation and Rate Design Application Costs	32	-	-	-	(32)	-	-	-	16	
6	2015-2019 Annual Review Costs	178	-	140	(36)	(178)	-	-	104	141	
7	2017 Rate Design Application	696	-	940	(244)	-	-	-	1,392	1,044	
8	2017 Long Term Resource Plan Application	374	-	545	(142)	-	-	-	777	576	
9	LMIPSU Application Costs	240	-	-	-	(120)	-	-	120	180	
10	2015 System Extension Application	135	-	-	-	(135)	-	-	-	68	
11	BERC Rate Methodology Application	23	-	-	-	(23)	-	-	-	12	
12	All-Inclusive Code of Conduct/Transfer Pricing Policy Application	115	-	-	-	(115)	-	-	-	58	
13		$ 3,908	$ -	$ 1,625	$ (422)	$ (1,343)	$ -	$ -	$ 3,768	$ 3,841	
14	Other Deferral Accounts										
15	Whistler Pipeline Conversion	$ 9,406	$ -	$ -	$ -	$ (739)	$ -	$ -	$ 8,667	$ 9,037	
16	2010-2011 Customer Service O&M and COS	11,309	-	-	-	(3,251)	-	-	8,058	9,684	
17	Gas Asset Records Project	2,006	-	1,680	(437)	(502)	-	-	2,747	2,377	
18	BC OneCall Project	720	-	128	(33)	(237)	-	-	578	649	
19	Gains and Losses on Asset Disposition	28,416	-	-	-	(3,987)	-	-	24,429	26,423	
20	Net Salvage Provision/Cost	(46,462)	-	13,233	-	(34,671)	-	-	(67,900)	(57,181)	
21	TESDA Overhead Allocation Variance	639	-	-	-	(639)	-	-	-	320	
22	PCEC Start Up Costs	832	-	-	-	(44)	-	-	788	810	
23	Huntingdon CPCN Pre-Feasibility Costs	244	-	-	-	(122)	-	-	122	183	
24	LMIPSU Development Costs	1,561	-	-	-	(780)	-	-	781	1,171	
25		$ 8,671	$ -	$ 15,041	$ (470)	$ (44,972)	$ -	$ -	$ (21,730)	$ (6,527)	
26	Residual Deferred Accounts										
27	BFI Costs and Recoveries	$ (260)	$ -	$ -	$ -	$ -	$ -	$ -	$ (260)	$ (260)	
28	Residual Delivery Rate Riders	2	-	-	-	(2)	-	-	-	1	
29	Property Tax Deferral	(8)	-	-	-	8	-	-	-	(4)	
30		$ (266)	$ -	$ -	$ -	$ 6	$ -	$ -	$ (260)	$ (263)	
31											
32	**Total**	$ 10,466	$ 13,127	$ 81,866	$ (17,844)	$ (51,559)	$ (20,487)	$ 5,328	$ 20,897	$ 22,249	
33	Less: Net Salvage Amortization Transferred to Biomethane BVA					22					
34	**Net Rate Base Deferred Amortization Expense**					$ (51,537)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	12/31/2016	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2017	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Rate Base**										
2	Biomethane Variance Account	$ 1,320	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,320	$ 1,320	
3	KORP Feasibility Costs	-	-	-	-	-	-	-	-	-	
4	EEC-Incentives	13,127	(13,127)	-	-	-	-	-	-	-	
5	US GAAP Uncertain Tax Positions	277	-	-	-	-	-	-	277	277	
6	Mark to Market - Hedging Transactions	17,307	-	-	-	-	-	-	17,307	17,307	
7	Amalgamation Regulatory Account	578	-	8	-	-	(792)	206	-	289	
8	2014-2019 Earning Sharing Account	(3,684)	-	(101)	-	3,785	-	-	-	(1,842)	
9	Flow-Through Account	(5,022)	-	(138)	-	5,160	-	-	-	(2,511)	
10	Phase-In-Rider Balancing Account	(3,344)	-	-	-	-	4,519	(1,175)	-	(1,672)	
11	PEC Pipeline Development Costs and Commitment Fees	8,853	-	-	-	-	-	-	8,853	8,853	
12	Rate Stabilization Deferral Account (RSDA)	(15,211)	-	(143)	37	-	20,699	(5,382)	-	(7,606)	
13	**Total Non Rate Base Deferral Accounts**	$ 14,201	$ (13,127)	$ (374)	$ 37	$ 8,945	$ 24,426	$ (6,351)	$ 27,757	$ 14,415	

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 13,263	$ 15,072	$ 1,809	Schedule 14, Line 29, Column 5
3					
4	Less: Funds Available				
5	Reserve for bad debts	(5,597)	(4,947)	650	
6	Employee Withholdings	(5,537)	(5,326)	211	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	2,332	1,537	(795)	
10	Gas In Storage	55,331	42,032	(13,299)	
11	Inventory - Materials and Supplied	1,567	1,567	-	
12	Refundable Contributions	(311)	(311)	-	
13					
14	Total	$ 61,048	$ 49,624	$ (11,424)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2017 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	$ 967,778	38.3	$ 37,093,698		
4	Industrial Tariff Revenue	80,371	45.1	3,626,373		
5	Bypass and Special Rates	40,663	43.6	1,771,933		
6						
7	**Other Revenue**					
8	Late Payment Charges	2,178	38.3	83,417		
9	Connection Charges	3,118	38.3	119,419		
10	Other Utility Income	37,660	38.3	1,442,378		
11						
12	Total	$ 1,131,768		$ 44,137,218	39.0	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 299,294	(40.2)	$ (12,031,619)		
16	Operating and Maintenance	238,005	(25.5)	(6,069,138)		
17	Property Taxes	67,450	(2.0)	(134,900)		
18	Franchise Fees	7,330	(420.3)	(3,080,918)		
19	Carbon Tax	188,110	(29.1)	(5,474,001)		
20	GST	9,464	(38.8)	(367,203)		
21	PST	3,741	(37.1)	(138,791)		
22	Income Tax	46,180	(15.2)	(701,936)		
23						
24	Total	$ 859,575		$ (27,998,506)	(32.6)	
25						
26	Net Lag (Lead) Days				6.4	
27	Total Expenses				$ 859,575	
28						
29	Cash Working Capital				$ 15,072	

Schedule 15

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 APPROVED	2017 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (285,802)	$ (305,906)	$ (20,104)	
2	Tax Gross Up	(100,417)	(107,481)	(7,064)	
3	DIT Liability/Asset - End of Year	$ (386,219)	$ (413,387)	$ (27,168)	
4	DIT Liability/Asset - Opening Balance	(390,672)	(400,709)	(10,037)	
5					
6	DIT Liability/Asset - Mid Year	$ (388,446)	$ (407,048)	$ (18,602)	

UTILITY INCOME AND EARNED RETURN Schedule 16
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 FORECAST at Existing Rates	Revised Revenue	at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	121,772	126,266		126,266	4,494	
3	Transportation Volume (TJ)	86,003	89,522		89,522	3,519	
4		207,775	215,787	-	215,787	8,012	Schedule 17, Line 25, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,114,526	$ 958,461	$ -	$ 958,461	$ (156,065)	
8	Deficiency (Surplus)	-	-	8,093	8,093	8,093	
9	Transportation	123,011	121,032	-	121,032	(1,979)	
10	Deficiency (Surplus)	-		1,226	1,226	1,226	
11	Total	1,237,537	1,079,493	9,319	1,088,812	(148,725)	Schedule 19, Line 31, Column 8
12				-			
13	**COST OF ENERGY**	477,714	299,294	-	299,294	(178,420)	Schedule 18, Line 25, Column 3
14							
15	**MARGIN**	759,823	780,199	9,319	789,518	29,695	
16							
17	**EXPENSES**						
18	O&M Expense (net)	238,067	238,005	-	238,005	(62)	Schedule 20, Line 36, Column 4
19	Depreciation & Amortization	199,490	214,096	-	214,096	14,606	Schedule 21, Line 15, Column 3
20	Property Taxes	63,036	67,450	-	67,450	4,414	Schedule 22, Line 8, Column 3
21	Other Revenue	(41,852)	(42,956)	-	(42,956)	(1,104)	Schedule 23, Line 12, Column 3
22	Utility Income Before Income Taxes	301,082	303,604	9,319	312,923	11,841	
23							
24	Income Taxes	46,173	43,641	2,539	46,180	7	Schedule 24, Line 13, Column 3
25							
26	**EARNED RETURN**	$ 254,909	$ 259,963	$ 6,780	$ 266,743	$ 11,834	Schedule 26, Line 5, Column 7
27							
28	**UTILITY RATE BASE**	$ 3,692,697	$ 4,140,662		$ 4,140,710	$ 448,013	Schedule 2, Line 29, Column 3
29	**RATE OF RETURN ON UTILITY RATE BASE**	6.90%	6.28%		6.44%	-0.46%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	72,466.1	74,279.4	1,813.3	
4	Commercial				
5	Rate Schedule 2	28,012.1	28,522.9	510.8	
6	Rate Schedule 3	18,121.3	18,620.8	499.5	
7	Rate Schedule 23	8,968.8	9,175.6	206.8	
8	Industrial				
9	Rate Schedule 4	129.9	148.2	18.3	
10	Rate Schedule 5	2,172.7	2,189.0	16.3	
11	Rate Schedule 6	46.8	54.2	7.4	
12	Rate Schedule 7	154.6	148.8	(5.8)	
13	Rate Schedule 22 - Firm Service	9,878.9	11,193.8	1,314.9	
14	Rate Schedule 22 - Interruptible Service	17,616.4	18,486.9	870.5	
15	Rate Schedule 25	13,490.2	13,650.5	160.3	
16	Rate Schedule 27	6,536.7	6,414.5	(122.2)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	8,395.8	8,298.0	(97.8)	
19	Rate Schedule 25	850.9	884.8	33.9	
20	Rate Schedule 46	668.7	2,302.3	1,633.6	
21	Byron Creek	375.4	247.6	(127.8)	
22	Burrard Thermal	186.4	-	(186.4)	
23	BC Hydro ICP	14,945.0	16,425.0	1,480.0	
24	VIGJV	4,758.0	4,745.0	(13.0)	
25	Total	207,774.7	215,787.3	8,012.6	
26					
27	**REVENUE AT EXISTING RATES**				
28	Residential				
29	Rate Schedule 1	$ 730,278	$ 629,134	$ (101,144)	
30	Commercial				
31	Rate Schedule 2	$ 235,076	194,560	(40,516)	
32	Rate Schedule 3	$ 129,052	104,284	(24,768)	
33	Rate Schedule 23	$ 30,574	31,404	830	
34	Industrial				
35	Rate Schedule 4	$ 694	558	(136)	
36	Rate Schedule 5	$ 13,551	10,202	(3,349)	
37	Rate Schedule 6	$ 358	331	(27)	
38	Rate Schedule 7	$ 778	525	(253)	
39	Rate Schedule 22 - Firm Service	$ 6,259	6,834	575	
40	Rate Schedule 22 - Interruptible Service	$ 18,184	19,666	1,482	
41	Rate Schedule 25	$ 30,605	31,423	818	
42	Rate Schedule 27	$ 10,082	9,909	(173)	
43	Bypass and Special Rates				
44	Rate Schedule 22 - Firm Service	$ 846	1,038	192	
45	Rate Schedule 25	$ 435	315	(120)	
46	Rate Schedule 46	$ 4,739	18,867	14,128	
47	Byron Creek	$ 44	122	78	
48	Burrard Thermal	$ 8,314	-	(8,314)	
49	BC Hydro ICP	$ 13,097	15,735	2,638	
50	VIGJV	$ 4,572	4,586	14	
51	Total	$ 1,237,537	$ 1,079,493	$ (158,045)	

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 287,645	$ 176,322	$ (111,323)	
4	Commercial				
5	Rate Schedule 2	111,133	68,253	(42,880)	
6	Rate Schedule 3	67,784	41,047	(26,737)	
7	Rate Schedule 23	182	136	(46)	
8	Industrial				
9	Rate Schedule 4	432	270	(162)	
10	Rate Schedule 5	7,219	3,988	(3,231)	
11	Rate Schedule 6	136	80	(56)	
12	Rate Schedule 7	514	271	(243)	
13	Rate Schedule 22 - Firm Service	225	241	16	
14	Rate Schedule 22 - Interruptible Service	268	199	(69)	
15	Rate Schedule 25	241	191	(50)	
16	Rate Schedule 27	131	95	(36)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	125	123	(2)	
19	Rate Schedule 25	13	13	-	
20	Rate Schedule 46	1,662	8,065	6,403	
21	Byron Creek	-	-	-	
22	Burrard Thermal	4	-	(4)	
23	BC Hydro ICP	-	-	-	
24	VIGJV	-	-	-	
25	Total	$ 477,714	$ 299,294	$ (178,420)	

FORTISBC ENERGY INC.

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved Margin	2017 FORECAST Margin at Existing Rates	Effective Increase	Margin at Revised Rates	2017 FORECAST Revenue at Existing Rates	Effective Increase	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	$ 442,632	$ 452,812	$ 5,644	$ 458,456	$ 629,134	$ 5,644	$ 634,778	902,984	74,279.4	
4	Commercial										
5	Rate Schedule 2	123,943	126,307	1,574	127,881	194,560	1,574	196,134	86,684	28,522.9	
6	Rate Schedule 3	61,268	63,237	788	64,025	104,284	788	105,072	5,356	18,620.8	
7	Rate Schedule 23	30,392	31,268	390	31,658	31,404	390	31,794	1,756	9,175.6	
8	Industrial										
9	Rate Schedule 4	261	288	4	292	558	4	562	19	148.2	
10	Rate Schedule 5	6,333	6,214	77	6,291	10,202	77	10,279	233	2,189.0	
11	Rate Schedule 6	223	251	3	254	331	3	334	8	54.2	
12	Rate Schedule 7	263	254	3	257	525	3	528	5	148.8	
13	Rate Schedule 22 - Firm Service	6,035	6,593	82	6,675	6,834	82	6,916	14	11,193.8	
14	Rate Schedule 22 - Interruptible Service	17,916	19,467	243	19,710	19,666	243	19,909	28	18,486.9	
15	Rate Schedule 25	30,365	31,232	389	31,621	31,423	389	31,812	556	13,650.5	
16	Rate Schedule 27	9,951	9,814	122	9,936	9,909	122	10,031	107	6,414.5	
17	Total Non-Bypass	$ 729,581	$ 747,737	$ 9,319	$ 757,056	$ 1,038,830	$ 9,319	$ 1,048,149	997,750	182,884.6	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 721	$ 915		$ 915	$ 1,038		$ 1,038	7	8,298.0	
22	Rate Schedule 25	422	302		302	315		315	4	884.8	
23	Rate Schedule 46	3,076	10,802		10,802	18,867		18,867	11	2,302.3	
24	Byron Creek	44	122		122	122		122	1	247.6	
25	Burrard Thermal	8,310	-		-	-		-	-	-	
26	BC Hydro ICP	13,097	15,735		15,735	15,735		15,735	1	16,425.0	
27	VIGJV	4,572	4,586		4,586	4,586		4,586	1	4,745.0	
28	Total Bypass & Special	$ 30,242	$ 32,462	$ -	$ 32,462	$ 40,663	$ -	$ 40,663	25	32,902.7	
29											
30											
31	Total	$ 759,823	$ 780,199	$ 9,319	$ 789,518	$ 1,079,493	$ 9,319	$ 1,088,812	997,775	215,787.3	
32											
33	**Effective Increase**			1.19%			0.86%				

OPERATING AND MAINTENANCE EXPENSE Schedule 20
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars (1)	Formula O&M (2)	Forecast O&M (3)	Total O&M (4)	Cross Reference (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	100.976%			Schedule 3, Line 12, Column 6
23	Formula O&M	$ 240,362		$ 240,362	
24					
25	**O&M Tracked Outside of Formula**				
26	Pension & OPEB (O&M Portion)		$ 15,826		
27	Insurance		5,529		
28	Biomethane O&M		976		
29	NGT Stations O&M		1,494		
30	LNG O&M		7,310		
31	Total		$ 31,135	31,135	
32					
33	**Total Gross O&M**			$ 271,497	
34	O&M Transferred to Biomethane BVA			(912)	
35	Capitalized Overhead			(32,580)	
36	**Net O&M Expense**			$ 238,005	

Schedule 21

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 172,477	$ 182,199	$ 9,722	Schedule 7.2, Line 38, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(547)	(399)	148	Schedule 7.2, Line 39, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,582)	(1,334)	248	Schedule 7.2, Line 40, Column 7
5		170,348	180,466	10,118	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 45,033	$ 51,559	$ 6,526	Schedule 11.1, Line 32, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA		(22)	(22)	Schedule 11.1, Line 33, Column 6
10	Non-Rate Base Deferrals	(4,943)	(8,945)	(4,002)	Schedule 12, Line 13, Column 6
11	CIAC	(10,984)	(8,989)	1,995	Schedule 9, Line 15, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	36	27	(9)	Schedule 9, Line 21, Column 5
13		29,142	33,630	4,488	
14					
15	Total	$ 199,490	$ 214,096	$ 14,606	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 APPROVED	2017 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 49,521	$ 54,832	$ 5,311	
2	1% In-Lieu of Municipal Taxes	13,522	12,629	(893)	
3					
4	Total	$ 63,043	$ 67,461	$ 4,418	
5					
6	Total Property Tax Expense per Line 4	$ 63,043	$ 67,461		
7	Less: Property Tax Transferred to Biomethane BVA	(7)	(11)		
8	**Net Property Tax Expense**	$ 63,036	$ 67,450		

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,314	$ 2,178	$ (136)	
2	Connection Charge	3,060	3,118	58	
3	NSF Returned Cheque Charges	88	76	(12)	
4	Other Recoveries	202	243	41	
5	SCP Third Party Revenue	14,957	14,347	(610)	
6	NGT Tanker Rental Revenue	209	448	239	
7	NGT Overhead and Marketing Recovery	263	332	69	
8	Biomethane Other Revenue	294	448	154	
9	LNG Mitigation Revenue from FEI	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,426	3,727	1,301	
11					
12	Total	$ 41,852	$ 42,956	$ 1,104	

INCOME TAXES Schedule 24
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 254,909	$ 266,743	$ 11,834	Schedule 16, Line 26, Column 5
2	Deduct: Interest on Debt	(130,511)	(127,253)	3,258	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	7,017	(8,054)	(15,071)	Schedule 24, Line 38
4	Accounting Income After Tax	$ 131,415	$ 131,436	$ 21	
5					
6	1 - Current Income Tax Rate	74.00%	74.00%	0.00%	
7	Taxable Income	$ 177,588	$ 177,616	$ 28	
8					
9	Current Income Tax Rate	26.00%	26.00%	0.00%	
10	Income Tax - Current	$ 46,173	$ 46,180	$ 7	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 46,173	$ 46,180	$ 7	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,000	$ 1,000	$ -	
19	Depreciation	170,348	180,466	10,118	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	40,090	42,592	2,502	Schedule 21, Line 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	879	832	(47)	
22	Vehicles: Interest & Capitalized Depreciation	1,791	1,543	(248)	
23	Pension Expense	18,969	12,044	(6,925)	
24	OPEB Expense	10,938	7,500	(3,438)	
25					
26	Deductions:				
27	Capital Cost Allowance	(174,396)	(195,513)	(21,117)	Schedule 25, Line 21, Column 6
28	CIAC Amortization	(10,948)	(8,962)	1,986	Schedule 21, Line 11+12, Column 3
29	Cumulative Eligible Capital Allowance	(1,736)	(1,572)	164	
30	Debt Issue Costs	(1,233)	(902)	331	
31	Vehicle Lease Payment	(2,567)	(2,259)	308	
32	Pension Contributions	(15,903)	(15,496)	407	
33	OPEB Contributions	(3,487)	(3,324)	163	
34	Overheads Capitalized Expensed for Tax Purposes	(10,865)	(10,861)	4	
35	Removal Costs	(13,661)	(13,233)	428	Schedule 11.1, Line 20, Column 4
36	Major Inspection Costs	(1,908)	(1,909)	(1)	
37	Biomethane Other Revenue	(294)	-	294	
38	Total	$ 7,017	$ (8,054)	$ (15,071)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Class	CCA Rate	12/31/2016 UCC Balance	Adjustments	2017 Additions	2017 CCA	12/31/2017 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 1,133,534	$ -	$ 2,815	$ (45,397)	$ 1,090,952
2	1(b)	6%	67,657	-	7,316	(4,279)	70,694
3	2	6%	111,268	-	-	(6,676)	104,592
4	3	5%	2,074	-	-	(104)	1,970
5	6	10%	102	-	-	(10)	92
6	7	15%	16,747	-	2,482	(2,698)	16,531
7	8	20%	26,407	-	7,163	(5,998)	27,572
8	10	30%	7,152	-	2,684	(2,548)	7,288
9	12	100%	6,533	-	13,069	(13,068)	6,534
10	13	manual	3,823	-	196	(470)	3,549
11	14	manual	150	-	-	(25)	125
12	17	8%	1,460	-	-	(117)	1,343
13	38	30%	5,184	-	870	(1,686)	4,368
14	43.2	50%	2,446	-	-	(1,223)	1,223
15	45	45%	20	-	-	(9)	11
16	47	8%	471,893	-	2,204	(37,839)	436,258
17	49	8%	147,772	-	169,674	(18,609)	298,837
18	50	55%	10,952	-	9,441	(8,620)	11,773
19	51	6%	709,567	-	118,761	(46,137)	782,191
20							
21	Total		$ 2,724,741	$ -	$ 336,675	$ (195,513)	$ 2,865,903

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 APPROVED Earned Return	Amount	Ratio	2017 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 128,940	$ 2,291,713	55.35%	5.40%	2.99%	$ 123,685	$ (5,255)	Schedule 27, Line 27&29, Column 5&6&7
2	Short Term Debt	1,571	254,824	6.15%	1.40%	0.09%	3,568	1,997	
3	Common Equity	124,398	1,594,173	38.50%	8.75%	3.37%	139,490	15,092	
4									
5	Total	$ 254,909	$ 4,140,710	100.00%		6.44%	$ 266,743	$ 11,834	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	$ 147,710	$ 150,000	7.073%	$ 10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	117,349	118,534	2.695%	3,194	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,500	150,000	3.726%	5,589	
12	2016 Medium Term Debt Issue - Series 29	November 1, 2016	November 1, 2046	198,000	200,000	3.957%	7,914	
13								
14	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
15	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
16								
17	LILO Obligations - Kelowna				18,177	6.536%	1,188	
18	LILO Obligations - Nelson				2,971	8.381%	249	
19	LILO Obligations - Vernon				8,752	9.735%	852	
20	LILO Obligations - Prince George				22,971	8.589%	1,973	
21	LILO Obligations - Creston				2,200	7.682%	169	
22								
23	Vehicle Lease Obligation				4,295	4.866%	209	
24								
25	Sub-Total				$ 2,297,900		$ 124,019	
26	Less: Fort Nelson Division Portion of Long Term Debt				(6,187)		(334)	
27	Total				$ 2,291,713		$ 123,685	
28								
29	Average Embedded Cost					5.40%		
30								
31	* 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 (none of which are identified for 2017), emerging accounting guidance, its conclusions on the relationship between the code of accounts and future benchmarking studies, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI reports on the Kingsvale-Oliver Reinforcement Project Feasibility Costs and Flow-through deferral accounts in this section.

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.

For 2017, FEI has not identified any items that merit exogenous factor treatment.

12.3 *ACCOUNTING MATTERS*

In the following two sections, FEI provides information on emerging accounting guidance and on its code of accounts.

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 three US GAAP accounting standards below, none of which impact the accounting policies or rate forecasts for 2017.

12.3.1.1 Revenue Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* and the amendments in this update created Accounting Standard Codification (ASC) Topic 606. This standard completes a joint effort by FASB and the International Accounting Standards Board (IASB) to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards (IFRS) that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016. In August 2015, FASB issued ASU No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU No. 2015-14 defers the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017, which is January 1, 2018 for FEI.

Three ASU's were issued in 2016 to clarify implementation guidance in ASC Topic 606. ASU No. 2016-08, *Principal versus Agent Considerations*, was issued in March 2016; ASU No. 2016-10, *Identifying Performance Obligations and Licensing*, was issued in April 2016; and ASU No. 2016-12, *Narrow-Scope Improvements and Practical Expedients,* was issued in May 2016. The effective date of these updates is the same as the effective date and transition requirements of ASU No. 2014-09.

ASU No. 2014-09 is not expected to significantly change current practice for rate-regulated operations that use published tariff rates to recognize revenue upon delivery of natural gas to a customer meter. FEI is revisiting its revenue contracts associated with take-or-pay arrangements and any bundled arrangements. FEI is also revisiting the accounting treatment of contributions in aid of construction under ASU No. 2014-09. Any long-term sale arrangements will need to be aggregated and documented to determine whether the terms result in changes to how revenue is recognized under ASU No. 2014-09. There are various situations that could arise which could change the timing of when revenue is recognized, resulting in revenue being deferred on the balance sheet. FEI has not yet selected a transition method and is assessing the impact that the adoption of this standard, and all related ASUs, will have on its consolidated financial statements and related disclosures. FEI plans to have this assessment substantially complete by the end of 2016 and will provide an update in the Annual Review for 2018 Rates.

12.3.1.2 Leases

In February 2016, FASB issued ASU No. 2016-02, *Leases (Topic 842*) which supersedes lease requirements in ASC Topic 840, *Leases*. This standard increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This standard is effective for FEI for annual and interim periods beginning on January 1, 2019 and early adoption is permitted. The main provision of 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. 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 expenses and cash flows arising from a lease by a lessee have not significantly changed from current US GAAP.

The new guidance will result in operating leases being recognized as assets and liabilities on the balance sheet. FEI has building operating leases which could potentially be recorded as assets and liabilities on the balance sheet. The new standard either classifies lease costs as interest and depreciation or as a rent expense, depending on the type of classification under this new lease standard. FEI is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures and will provide an update in the Annual Review for 2018 Rates.

12.3.1.3 Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In January 2016, FASB issued a proposed ASU, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (net benefit cost). Currently, it is not known when a final standard will be issued and FASB has not set an effective date for the standard.

As approved by the BCUC, FEI capitalizes net benefit costs related to pension and other post-retirement benefits (OPEB) to property, plant and equipment with the balance expensed as operating costs in the income statement. The proposed ASU would allow only the service cost component of net benefit costs to be eligible for capitalization, while the other components would not be eligible to be capitalized. This proposed standard could result in a decrease in the amount of pension and OPEB costs currently allocated to capital and an increase in the net benefit costs currently recognized in the income statement. Rate-regulated entities have commented on the proposed ASU and are proposing that rate-regulated entities be allowed to continue to capitalize all components of net benefit costs related to pension and OPEB to property, plant and equipment. FEI will monitor the progress of this standard and provide an update in the Annual Review for 2018 Rates.

12.3.2 Code of Accounts

In Order G-15-15 that approved the continued use of the New Code of Accounts for O&M expenses by FEI, the Commission directed FEI to file a proposal to deal with any benchmarking difficulties that may arise from the use of its New Code of Accounts by (NCoA) no later than the third annual PBR Review. Since this annual review is the third annual review under FEI's PBR Plan, FEI provides below its response to that directive. FEI's conclusion is that the NCoA can continue to be used without impairing the ability to benchmark FEI's efficiency relative to other utilities when determining any stretch factor.

12.3.2.1 Background

The NCoA was approved for use in O&M reporting in 2008, and has been used since that time. In the PBR proceeding, FEI submitted that the NCoA should continue to be utilized. The existing NCoA approach provides more meaningful and comparable information than the BCUC Uniform System of Accounts (USoA), which has not been substantially updated since 1961, and at no additional cost to customers[59].

The Commission did not approve the continued use of the NCoA initially, stating that the USoA would provide more consistent and comparable information at an account level over time and assist in benchmarking by increasing the comparability of reporting with other jurisdictions that use the USoA[60].

Regarding benchmarking, the Commission stated:

> The Commission Panel agrees with ICG that there is a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.[61]

FEI understood this directive to be addressing benchmarking that could inform any "stretch factor" to be added to the results of the industry-based Total Factor Productivity growth, or TFP, studies when deriving the X Factor.

FEI sought reconsideration of (among other things) the Commission's requirement that FEI revert back to the USoA for O&M reporting. FEI explained that adoption of the USoA would not result in the benefits anticipated by the Commission but would incur material work effort and expenditures[62]. FEI also submitted that adopting the USoA may not assist with benchmarking for the following reason:

> Although the USoA is similar to those in place in Ontario and Alberta, having the same accounts will not assist in benchmarking if the items captured in each account differ. This will occur due to different programs in place in different jurisdictions (for example the existence of natural gas for transportation in the FEU), utilities being vertically integrated in BC as compared to separation of the functions in Alberta, utilities following different accounting standards, and different approved capitalization policies.[63]

59 FEI Submission on non-PBR Issues in PBR Proceeding, p. 65.
60 PBR Decision, p. 248.
61 PBR Decision, p. 82.
62 Reconsideration Proceeding, Exhibit B-1, p. 11 and Exhibit B-3, p. 22.
63 Reconsideration Proceeding, Exhibit B-3, p. 21.

In Order G-15-15 in the Reconsideration Proceeding, the Commission approved FEI to continue utilizing its NCoA for O&M reporting rather than the USoA, but directed that FEI address any benchmarking difficulties that may arise from continued use of the New Code of Accounts in this Annual Review[64].

FEI provides below its response to the Commission's directive regarding benchmarking and the NCoA.

12.3.2.2 Summary of New Code of Accounts

FEI provides below its summary of the comparison of the USoA and NCoA from its BCUC Uniform System of Accounts Report filed October 10, 2012, section 4.2.1. The comparison emphasizes that there is general consistency in the information provided in both systems of account. The general comparability helps to explain why the NCoA is also compatible with benchmarking:

> In Attachment 3, the FEU have provided a line by line comparison of the BCUC USoA for O&M accounts to the New Code of Accounts. Based on this analysis, the FEU are able to conclude that there are no significant differences between the two in terms of the information provided. At a high level, the detailed comparison provided in Attachment 3 is summarized below in terms of any differences that were found.
>
> There are accounts where the New Codes of Accounts provides less information, and these accounts are primarily those where the FEU do not separately manage activities at the BCUC USoA level of detail, so that meaningful information cannot be provided. The main areas where this occurs are:
>
> - Transmission Supervision and Distribution Supervision accounts – The FEU do not have individuals that separately manage the Maintenance vs. Operations of these two areas as this would not be an efficient way to operate the utility. Accordingly, any allocation of FEU supervision between maintenance and operations would be arbitrary and unexplainable.
> - Communication, and Measuring and Regulating accounts – With an integrated system and current technology, it is no longer possible to draw a clear line in these areas between transmission and distribution and the monitoring of those systems. Accordingly, any allocation of these accounts between transmission and distribution would be arbitrary and unexplainable.
> - Engineering accounts – The FEU do not separate engineering activities between transmission and distribution. Accordingly, any allocation of these costs between transmission and distribution would be arbitrary and unexplainable.
>
> There are accounts where the New Code of Accounts provides more information, reflecting how the FEU manage these activities at a more granular level and are

[64] Appendix A to Order G-15-15, page 11.

therefore able to provide this information in a meaningful way. The main areas where this occurs are:

- Right of Way and TPIP accounts provide additional detail not provided elsewhere.
- Much greater granularity provided compared to the BCUC "Other General Operations" account where the FEU provide six separate accounts instead of one.
- Much greater granularity provided compared to the BCUC "Administration Expense" account where the FEU provide 12 separate accounts instead of one.
- The FEU provide 12 separate accounts in the Resource View that provide information over and above the requirements of the BCUC USoA; the BCUC USoA is more similar to an activity view of operations.

For all of the accounts in the New Code of Accounts, whether the Activity View or the Resource View, the FEU are able to provide a lower level of analysis than shown (cost centre level for the Activity View and cost element level for the Resource View), although as stated above, the comparability over time decreases as more granularity is provided. For example, if an entire cost centre is moved to report to a different account to align with a reorganization or a change in business activities, the SAP system can restate the historical comparatives for the requested reporting period. Managers remain assigned as responsible for that cost centre and are able to provide analysis of the changes in the activities and costs of that cost centre over time. At any level of reporting below the cost centre level, there is no data readily available from the SAP system, and there is no individual manager responsible to explain those costs. Historical information cannot be reconciled at a lower level of detail.

12.3.2.3 Benchmarking and the Code of Accounts

There are different types of benchmarking techniques that can be used to compare the operational efficiency of a company with its peers,[65] and in some cases they can also be used to compare the efficiency of a company with itself over time[66]. These techniques can be generally classified into two broad categories; parametric (econometric) and non-parametric approaches. The consultant will ultimately provide advice on which approach is used, but the key point is that the use of the NCoA is compatible with all benchmarking approaches and may have advantages over the USoA due to the factors discussed in Section 12.3.2.2.

At a high level, parametric techniques are based on statistical analysis of factors that affect the costs of a company in order to determine the cost efficiency of companies. Under the econometric benchmarking approach, a company's costs are estimated as a function of business conditions that the company faces. In comparison, non-parametric techniques

[65] PEG, July 2001, "External Benchmarks, Benchmarking Methods, and Electricity Distribution Network Regulation, A Critical Evaluation", Chapter 3 discusses approaches for generating benchmarks for utility performance.
[66] PEG, September 2011, "Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulations Plans."

generally refer to cost indexing techniques ranging from unit cost benchmarking to productivity indexes (such as the TFP method that was used in 2014 PBR Proceeding to estimate industry total factor productivity growth). Productivity indexes allow for comparison of costs for two sets of business conditions that differ between companies; the amount of work performed and the price of inputs. For efficiency benchmarking purposes and in order to determine if a stretch factor is required or not, these methods can also be calculated as a relative difference compared to a benchmark at a point in time.

The NCoA is compatible with all approaches and is as compatible as the USoA because the comparison to other utilities or to the industry is not undertaken at such a granular level that the use of specific O&M line items is required. Instead, any analysis must focus on total O&M costs. For instance, under the productivity indexing approach, the total O&M productivity factor is the ratio of an output quantity index to an input quantity index. The decomposition of O&M expenses is required to construct input quantity indexes; however, this is done at a level that can be accommodated under FEI's NCoA. In fact, for O&M benchmarking the use of NCoA should be preferred since, as explained above, the break-down of O&M expenses to labour and non-labour in the resource view is readily apparent.

As an example, Enbridge Gas Distribution (EGD) retained a consultant to conduct a series of benchmarking analyses to compare its total OM&A expenses with its peers[67]. The benchmarking involved the decomposition of O&M expenses into two input categories: labour services (defined as the sum of O&M salaries and wages and pensions and other employee benefits) and non-labour O&M inputs (defined to be the total applicable O&M expenses net of these labour costs. A similar kind of cost break-down can be performed using FEI's NCoA, and splitting out the labour component is more transparent since the information is already presented in that manner.

As stated by the Alberta Utilities Commission (AUC) in its 2012 PBR Decision, items other than Code of Account differences may impose greater constraints on the use of efficiency benchmarking:

> In the Commission's view, the efficiency benchmarking analysis is prone to two major criticisms. First, as NERA and Dr. Carpenter explained, the efficiency levels are hard to estimate as this type of analysis requires a multitude of historical company-specific data, which exhibit a great deal of year to year volatility and are prone to errors …. More importantly, Dr. Makholm and Dr. Carpenter pointed out that in practice it is virtually impossible to determine whether a firm is or is not efficient by looking at benchmark data alone, since relative efficiency depends on a boundless number of variables, both observable and unobservable. Factors such as age of plant, soil type, weather and geography, customer density, etc., are to be taken into account when considering efficiency levels. In these circumstances, inadvertently leaving out an important productivity driver may invalidate the results of the study.

[67] PEG, February 2004; "The O&M Cost Performance of Enbridge Gas Distribution: Update".

These factors must be accounted for in the analysis. In EGD's benchmarking study for instance, the consultant considered the specific characteristics of EGD's operating and business conditions in its cost indexing and sought to improve the benchmarks by comparing EGD's performance with the sample norms for gas only distributors, large gas only distributors, large gas only distributors with at least normal urban core activities, in addition to a comparison to the full sample norm. The econometric method was also used to validate the results of the cost indexing approach.

In conclusion, continuing the use of the NCoA that has been in place since 2008 provides distinct benefits to the Company and customer, including:

- a structure that reflects how FEI operates, avoiding judgement-based cost allocations;
- greater granularity for the majority of the cost items;
- a resource view in addition to the activity view, which readily provides information on total labour and other resources; and
- the ability to drill down into further detail for the line items presented.

The NCoA is compatible with benchmarking, and FEI does not foresee issues with benchmarking against other utilities. This is because benchmarking would be undertaken at a higher level than the individual O&M line items that are affected by the use of any particular O&M code of accounts. In light of all of the considerations, FEI submits that it is appropriate to continue to use the NCoA.

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 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).

In the following sections, FEI is proposing to discontinue one deferral account. FEI also provides additional information for one of its recently-approved deferral accounts. Information on FEI's non-rate base Earnings Sharing, Phase-in Rider, and Rate Stabilization deferral accounts is included in Section 10.

12.4.1 Kingsvale-Oliver Reinforcement Project Feasibility Costs

The Commission approved the creation of the Kingsvale-Oliver Reinforcement Project (KORP) Feasibility Costs deferral account through Commission Order G-101-12. In the Decision, the

Commission directed FEI to establish a new non-rate base deferral account to record the Stage 2a feasibility expenses, to a maximum of $850 thousand, with treatment of interest rate and deferral period to be determined in the next revenue requirement. In the KORP status report filed with the Commission April 30, 2013, FEI amended the timeline for the completion of the KORP Project until November 2018 and provided justification for this revised timeline. Given the change in timing of the project, FEI delayed its proposal for disposition until a future Annual Review.

As of December 31, 2015, approximately $109 thousand in costs had been accumulated in the deferral account. Given the current status of the KORP project and the age of the costs in the deferral account, FEI does not believe these costs can provide any benefit for future development work on this project or any derivation of it. Therefore, FEI is proposing to expense these costs and to discontinue use of the account.

12.4.2 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.

Table 12-1: 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 2016 projected Flow-through amount of $1.137 million credit is shown in Table 12-2 below. To calculate the amount distributed to customers, FEI has also included the following adjustments:

- The difference between the projected ending 2015 deferral account balance embedded in 2016 delivery rates of a $0.713 million[68] credit and the actual ending 2015 deferral

[68] Annual Review of 2016 Rates Compliance Filing financial schedules, Schedule 12, Line 12, Column 2.

account balance of a $4.347 million credit, for a difference of a $3.634 million credit, and the associated financing adjustment of a $0.251 million credit for 2016.

- 2017 forecast financing of a $0.138 million credit[69]

Therefore, the total amount to return to customers through amortization in 2017 is a $5.160 million credit as shown in the non-rate base deferral section of the financial schedules in Section 11, Schedule 12.

Table 12-2: 2016 Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	Reference	2016 Approved	2016 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)	(5)
1	Delivery Margin				
2	Residential (Rate 1)		$ (442.632)	$ (443.150)	$ (0.518)
3	Commercial (Rate 2, 3, 23)		(215.603)	(217.567)	(1.964)
4	Industrial (All Others)		(101.588)	(104.974)	(3.386)
5	Total Delivery Margin		(759.823)	(765.691)	(5.868)
6					
7	O&M Tracked outside of Formula				
8	Insurance		6.275	5.755	(0.520)
9	Bio-Methane		1.022	1.071	0.049
10	Bio-Methane O&M transferred to BVA		(0.959)	(1.008)	(0.049)
11	NGT O&M		1.167	1.168	0.001
12	LNG Production O&M		0.870	1.634	0.764
13					
14	Property and Sundry Taxes		63.036	64.308	1.272
15					
16	Depreciation and Amortization		199.490	199.814	0.324
17					
18	Other Operating Revenue		(41.852)	(41.848)	0.004
19					
20	Interest Expense		130.511	129.123	(1.388)
21					
22	Income Taxes		46.173	50.447	4.274
23					
24	2016 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)				(1.137)
25					
26	2015 Ending Deferral Account Balance True-up				(3.634)
27	2016 Financing True-up				(0.251)
28	2017 Financing Addition to Deferral Account				(0.138)
29					
30	2017 After-Tax Amortization				(5.160)

The variances in delivery margin are due to favourable residential and commercial margin as a result of higher average customers than forecast while the favourable industrial margin is due to higher volumes than forecast and interruptible volumes for the Vancouver Island Joint Venture. Variances in O&M Tracked Outside the Formula is shown in Section 6 and Property Taxes are shown in Section 9. The variance in depreciation and amortization is primarily due to the timing of leased vehicle depreciation and higher depreciation of NGT assets. Variances in other

69 Section 11, Schedule 12, Line 9, Column 4.

Revenue are shown in Section 5. The variance in interest expense is due to both lower short-term debt (due to higher long-term debt than forecast) and a lower long-term debt average interest rate. 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 2016 subject to flow-through will be recorded in the deferral account in 2017 and amortized in 2018 rates.

12.5 *SUMMARY*

FEI does not have any exogenous factors that are affecting delivery rates in 2017 but has provided an update on certain accounting related matters, and has provided information to support its conclusion that the NCoA can continue to be used without impairing the ability to benchmark FEI's efficiency. In this section, FEI has also requested disposition of one of its non-rate base deferrals, and included information on the amounts recorded in another of its non-rate base deferrals.

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 2015 service quality to this section.

In the subsections below, FEI reports on its 2015 and June 2016 year-to-date performance as measured against the SQI benchmarks and thresholds. Both 2015 and June 2016 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2015, for the nine SQIs with benchmarks, seven performed at or better than the approved benchmarks with two, Emergency Response Time and All Injury Frequency Rate (AIFR), 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.

June 2016 year-to-date performance is similar to 2015 with eight SQIs with benchmarks now 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 2015 and June year-to-date performance for 2016 to the Commission-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation and that was approved by the Commission. Actual 2015 and June year-to-date results for 2016 are also provided for the four informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2015 Results	2016 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	97.3%	97.4%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	97.6%	98.7%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	2.95	2.42	1.88
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	9	9
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	81%	81%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	1.06	0.59
Meter Reading Accuracy	Number of scheduled meters that were read	95%	92%	97.5%	97.5%
Telephone Service Factor (Non- Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	93.8%	96.6%	96.9%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.6	8.7
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.0%	2.4%
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	2	1
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0045	0.0025

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2015 and 2016. 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 2015 result was 97.3 percent which was within the performance range with the benchmark at 97.7 percent and the threshold at 96.2 percent. The June 2016 year-to-date performance is 97.4 percent which is also between the threshold and the benchmark.

The Company's 2009 to 2015 annual and 2016 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 a decrease in the number emergency events and 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	June 2016 YTD
Results	97.7%	97.7%	97.9%	97.4%	97.4%	96.7%	97.3%	97.4%
Benchmark	n/a	n/a	n/a	n/a	n/a	97.7%	97.7%	97.7%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 result was 97.6 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2016 year-to-date performance is 98.7 percent which is also better than the benchmark.

The Company's TSF (Emergency) results for 2009 to 2015 annual and 2016 year-to-date are provided below:

Table 13-3: Historical TSF (Emergency) Results

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Results	98.3%	99.2%	96.5%	96.5%	95.6%	95.8%	97.6%	98.7%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 (three-year rolling average) result was 2.42 which was within the performance range with the benchmark at 2.08 and the threshold at 2.95. The 2015 annual AIFR was 2.52 as a result of 17 Medical Treatment and 18 Lost Time Injuries.

The three-year rolling average of the annual results including 2016 June year-to-date results is 1.88 which is better than the benchmark. The 2016 June year-to-date annual AIFR is 1.39 as a result of 6 Medical Treatment and 4 Lost Time injuries.

In 2015 and 2016, safety continues to be a core value for FEI and prevention of injury remains a key focus. FEI continues to focus and reinforce fundamentals of safe work planning, hazard identification and proper body positioning with all employees. As a part of the Company's focus on continual improvement, FEI launched the Target Zero safety program in January 2016. This program provides a structured format for employees at all levels to provide input into corporate safety, enabling the Company to better understand the current state of the safety culture and prioritize and implement initiatives that are relevant to employees. Aspects of the program include:

- Targeted and relevant safety communications to increase safety awareness with employees;
- Annual safety performance analysis developed for all departments;
- Safety action plans created by each department on an annual basis that form the blueprint for each department's continual safety improvement. The results are reviewed on a quarterly basis;
- An employee safety perception survey that allows the Company to better understand the current state of its safety culture and prioritize and implement initiatives that are relevant to employees; and
- An employee based safety program that brings together employees from all areas of the company to develop and implement safety initiatives that enables direct employee input to drive continual improvement.

Based on results to date in 2016, the Target Zero safety program appears to be having a positive impact on improving corporate safety.

The Company's 2009 to 2015 and 2016 year-to-date AIFR results are provided below. FEI notes that the 2013 and 2015 annual AIFR were impacted by ergonomic-related injuries.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Annual Results	2.49	2.66	1.66	1.91	3.02	1.73	2.52	1.39
Three year rolling average	2.55	2.26	2.27	2.08	2.20	2.22	2.42	1.88
Benchmark	n/a	n/a	n/a	n/a	n/a	2.08	2.08	2.08
Threshold	n/a	n/a	n/a	n/a	n/a	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 and reflects the trend and improvement in recent years.

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 2015 (three-year rolling average) result was 9, which is better than the benchmark of 16. The three-year rolling average of the June 2016 year-to-date results is also 9, 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 2015 annual and 2016 year-to-date results 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) as well as the declining historical trend in line damages.

Table 13-5: Historical Public Contact with Pipelines Results

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Annual Results	20	19	16	13	10	9	8	7
Three year rolling average	26	22	18	16	13	11	9	9
Benchmark	n/a	n/a	n/a	n/a	n/a	16	16	16
Threshold	n/a	n/a	n/a	n/a	n/a	16	16	16
Calls to BC One Call	72,691	78,734	82,396	86,828	92,002	107,509	122,627	68,286
Line Damages	1,435	1,457	1,329	1,094	955	954	1,035	511

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

First Contact Resolution

First Call 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 2015 result was 81 percent which was better than the benchmark of 78 percent approved by the Commission. The June 2016 year-to-date performance is also 81 percent and better than the benchmark.

The Company's 2009 to 2015 annual and 2016 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	June 2016 YTD
Annual Results	72%	77%	75%	78%	81%	80%	81%	81%
Benchmark	n/a	n/a	n/a	n/a	n/a	78%	78%	78%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 result was 1.06 which was better than the benchmark of 5.0. The June 2016 year-to-date performance is 0.59 which is also better than the benchmark. No significant billing issues have arisen in 2016.

The 2015 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2015 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%	99.98%	If (PA≥99.9%,5000*(1 - PA),1.05-PA))	0	0
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	99.15%	(100%-PA)*100	0.85	0.85
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	97.62%	(100%-PA)*100	2.38	2.38
Billing Service Quality Indicator; Target < 5.0		(Accuracy PA+Timeliness PA+Completion PA)/3	1.06	**1.06**

The Company's 2009 to 2015 annual and 2016 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.

Table 13-8: Historical Billing Index Results

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Annual Results	3.75	2.4	0.24	3.01	1.43	0.89	1.06	0.59
Benchmark	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 result was 97.5 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2016 year-to-date performance is 97.5 percent which is also better than the benchmark.

The Company's 2009 to 2015 annual and 2016 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	June 2016 YTD
Annual Results	n/a	n/a	n/a	n/a	92.5%	97.0%	97.5%	97.5%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 result was 71 percent which was better than the benchmark of 70 percent. The June 2016 year-to-date performance is 70 percent which is equal to the benchmark.

The Company's 2009 to 2015 annual and 2016 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	June 2016 YTD
	77%	77%	75%	76%	73%	75%		71%	70%
						Jan-Aug	Sept-Dec		
Benchmark	>=75%	>=75%	>=75%	>=75%	>=75%	>=75%	>=70%	70%	70%
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	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 2015 result was 96.6 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2016 year-to-date performance is 96.9 percent and also better than the benchmark. The June 2016 year-to-date result continues to improve on the performance observed in recent years.

The Company's 2009 to 2015 annual and 2016 year-to-date results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Annual Results	94.7%	94.2%	96.5%	96.5%	97.0%	95.5%	96.6%	96.9%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 result was 8.6, higher than the 8.5 score in 2014. The June 2016 year-to-date average index score is 8.7, higher than the 8.5 score for the same period last year. FEI believes the overall strong result is likely associated with a continued focus on call quality, improvements to the online experience and relatively small bill increases over the last few quarters due to commodity price and delivery margin levels. To date in 2016, FEI has seen continued strong and stable results attained for contact centre service (8.9), field services (9.4), and overall satisfaction (8.5).

The Company's 2009 to 2015 annual and 2016 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	June 2016 YTD
Annual Results – current format	n/a	n/a	8.3	8.3	8.3	8.5	8.6	8.7
Annual Results – prior format	80.1%	80.0%	79.3%	78.9%	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
Threshold	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 78.9percent and 8.3 in 2012.

Telephone Abandon Rate

The Telephone Abandon Rate is an informational, 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 2015 result was 2.0 percent and consistent with prior years' results. The June 2016 year-to-date result is 2.4 percent which is slightly higher than the Company's prior and full 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	June 2016 YTD
Annual Results	n/a	n/a	n/a	2.2%	2.1%	1.8%	2.0%	2.4%
Benchmark	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

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.

In the past, the practice has been to report only on the higher pressure transmission events designated as serious. However, the OGC has new reporting criteria effective October 1, 2014, which require 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 will likely increase the number of events reported going forward and will limit 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 and for June 2016 year-to-date by severity level.

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents in 2015	Reportable Incidents to June 30, 2016
Level 1 (moderate)	3	1
Level 2 (major)	0	0
Level 3 (serious)	0	0

As indicated in the above table, the 2015 result was three Level 1 reported incidents.

- The first Level 1 incident occurred in May 2015 at a residence in Surrey when a third party's excavator pulled and damaged a high pressure gas service impacting 20 customers. An FEI crew subsequently reinstated the service.
- The second Level 1 incident occurred in June 2015 at the compressor station in Warfield when an equipment failure (faulty diaphragm in pilot regulator) resulted in a leak at the valve station. The regulator was replaced.
- The third Level 1 incident occurred when a leak was detected on a section of the pipeline approved to be replaced in Burnaby as part of the LMIPSU Project, on November 3, 2015. The repair was completed and the pipeline re-gasified on November 9, 2015.

As also indicated in the table above, from January 1, 2016 to June 30, 2016, there has been one Level 1 reportable incident. The Level 1 incident was on March 21, 2016 and involved a leak detected during leak survey on a section of the pipeline approved to be replaced in Burnaby as part of the LMIPSU Project. The repair was completed and the pipeline was re-gasified on March 24, 2016.

The Company's 2009 to 2015 historical annual and 2016 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	June 2016 YTD
Annual Results – Level 1	n/a	n/a	n/a	n/a	n/a	1	3	1
Annual Results – Level 2	n/a	n/a	n/a	n/a	n/a	1	0	0
Annual Results – Level 3	n/a	n/a	n/a	n/a	n/a	0	0	0
Benchmark	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

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 2016 year-to-date five-year rolling average result of 0.0073 calculated using data from July 2011 to June 2016.

Table 13-16: June 2016 Year-to-Date Five Year Rolling Average

Period	Metric
July – December 2011 (6 months)	0.0039
January – December 2012	0.0089
January – December 2013	0.0075
January – December 2014	0.0059
January – December 2015	0.0045
January – June 2016 (6 months)	0.0025
Five Year Rolling Average	0.0073

The Company's 2009 to 2015 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 2015 five-year average is calculated using 2011 to 2015 annual data). The 2015 result was 0.0045 which is based on 102 leaks as compared to 114 in 2014 and 143 in 2013. The June 2016 year-to-date result is 0.0025 which is based on 56 leaks detected year to date as compared to 59 in 2015 and 74 in 2014 for the same 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
Leaks	122	140	166	169	143	114	102
Total km	18,760	18,895	18,974	19,040	19,098	19,172	22,602
Leaks per km	0.0065	0.0074	0.0087	0.0089	0.0075	0.0059	0.0045
5 year average	0.0062	0.0064	0.0067	0.0075	0.0078	0.0077	0.0071

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.

On March 31, 2016 FEI reported to the BC Ministry of Environment its 2015 GHG emissions of 120,997 tCO2e. The 2014 reported value was 140,507 tCO2e.

13.4 SUMMARY

In summary, FEI's 2015 results and June 2016 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2015, for those SQIs with benchmarks, seven performed at or better than the approved benchmarks with the remaining two 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.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: CANSIM Table 326-0020

Government of Canada / Gouvernement du Canada
Canada

Statistics Canada

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Table 326-0020[1, 2]
Consumer Price Index
monthly (2002=100)

Data table | Add/Remove data | Manipulate | Download | Related information | Help

The data below is a part of CANSIM table 326-0020. Use the Add/Remove data tab to customize your table.

Selected items [Add/Remove data]

Geography = British Columbia

Products and product groups[18]	All-items	Food[17]	Shelter[18]	Household operations, furnishings and equipment	Clothing and footwear	Transportation	Gasoline	Health and personal care	Recreation, education and reading	Alcoholic beverages and tobacco products	All-i excl food ener
2014 July	119.6	130.2	114.5	112.5	101.0	129.0	197.3	112.4	116.2	135.6	113.
2014 August	119.6	129.9	114.4	113.4	99.5	128.5	192.7	112.8	117.0	135.6	113.
2014 September	119.5	129.7	114.5	113.6	102.9	127.8	190.7	112.8	115.6	136.3	113.
2014 October	119.0	129.8	114.1	113.2	103.9	126.9	178.8	112.3	113.7	135.8	113.
2014 November	118.8	130.6	114.2	113.5	102.2	126.0	171.6	113.9	112.2	136.3	113.
2014 December	118.1	131.1	114.1	113.0	98.4	123.6	155.6	113.1	111.8	135.4	112.
2015 January	118.0	132.2	114.0	113.3	99.6	121.8	140.5	113.6	111.2	137.0	112.
2015 February	118.9	133.1	114.0	113.9	101.6	123.7	154.9	113.7	113.1	136.8	113.
2015 March	119.8	133.5	114.0	114.5	105.6	126.2	168.2	113.0	114.0	136.9	113.
2015 April	119.6	132.7	113.7	114.8	106.5	126.1	165.8	113.0	113.3	137.1	113.
2015 May	120.6	134.4	114.0	114.7	104.3	128.1	176.6	114.0	116.6	137.2	114.
2015 June	120.7	134.7	113.9	114.9	101.0	128.7	180.8	113.9	118.4	137.4	114.
2015 July	120.8	134.8	113.9	115.3	99.6	128.4	182.1	113.7	119.9	137.3	114.
2015 August	121.0	134.6	114.1	115.1	102.2	127.8	178.9	113.8	120.6	137.9	114.
2015 September	121.0	135.6	114.0	115.4	108.0	125.2	162.1	114.4	119.6	139.5	115.
2015 October	120.6	135.2	114.4	114.9	108.2	125.6	160.0	114.0	116.4	137.6	114.
2015 November	120.8	136.2	114.5	113.7	106.5	127.2	167.4	114.7	115.3	139.0	114.
2015 December	120.4	137.0	114.6	114.1	101.8	126.6	162.5	113.9	115.1	137.8	114.
2016 January	120.7	139.5	114.4	114.7	101.4	125.9	148.0	114.6	114.6	140.1	114.
2016 February	120.8	137.9	114.4	115.8	103.4	125.0	140.3	115.1	116.0	140.2	115.
2016 March	121.8	138.1	114.7	117.1	106.0	126.9	150.8	114.9	117.8	141.1	116.
2016 April	121.8	137.3	115.0	117.2	105.3	127.7	153.8	115.9	116.7	141.2	116.
2016 May	122.7	137.7	115.3	117.3	105.3	130.3	161.4	115.5	119.6	140.9	117.
2016 June	123.1	137.0	115.8	117.3	103.6	131.7	166.9	116.4	120.9	141.1	117.

Table A1-2: CANSIM Table 281-0063

Government of Canada / Gouvernement du Canada
Canada

Statistics Canada

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Table 281-0063[1, 11, 12, 13, 14]

Survey of Employment, Payrolls and Hours (SEPH), employment and average weekly earnings (including overtime) for all employees by North American Industry Classification System (NAICS), seasonally adjusted

monthly

Data table | Add/Remove data | Manipulate | Download | Related information | Help

The data below is a part of CANSIM table 281-0063. Use the Add/Remove data tab to customize your table.

Selected items [Add/Remove data]

Geography = British Columbia
Estimate = Average weekly earnings including overtime for all employees (dollars)[3]

North American Industry Classification System (NAICS)[14]	Industrial aggregate excluding unclassified businesses [11-91N][1, 2]	Goods producing industries [11-33N][4]	Forestry, logging and support [11N][5]	Mining, quarrying, and oil and gas extraction [21]	Utilities [22]	Construction [23]	Manufacturing [31-33]	Service producing industries [41-91N][6]	
2014 July	892.69[A]	1,147.91[A]	1,244.97[A]	1,760.15[B]	1,691.20[A]	1,118.17[A]	999.93[A]	843.26[A]	68
2014 August	902.67[A]	1,155.15[A]	1,144.61[A]	1,954.02[B]	1,876.24[A]	1,135.32[A]	1,022.57[A]	853.28[A]	69
2014 September	898.29[A]	1,162.28[A]	1,103.10[A]	1,998.27[A]	1,745.52[A]	1,136.66[A]	1,026.63[A]	846.29[A]	68
2014 October	904.76[A]	1,161.32[A]	1,152.62[A]	2,005.71[A]	1,726.06[A]	1,146.65[A]	1,010.79[A]	855.08[A]	67
2014 November	906.17[A]	1,150.20[A]	1,111.75[A]	1,939.69[A]	1,729.29[A]	1,140.03[A]	1,009.81[A]	857.64[A]	67
2014 December	895.32[A]	1,144.46[A]	1,153.41[A]	1,942.84[B]	1,646.87[A]	1,144.81[A]	986.96[A]	848.10[A]	68
2015 January	911.03[A]	1,168.95[A]	1,209.82[A]	1,890.75[B]	1,690.57[A]	1,169.65[A]	1,016.90[A]	863.65[A]	68
2015 February	909.02[A]	1,148.89[A]	1,197.83[A]	1,888.41[A]	1,700.44[A]	1,123.40[A]	1,044.74[A]	863.40[A]	68
2015 March	905.21[A]	1,147.75[A]	1,204.89[A]	1,984.66[A]	1,668.65[A]	1,124.51[A]	1,035.26[A]	859.68[A]	69
2015 April	903.26[A]	1,154.70[A]	1,213.84[A]	1,799.08[A]	1,630.94[A]	1,134.35[A]	1,046.13[A]	853.98[A]	68
2015 May	905.28[A]	1,145.30[A]	1,185.21[A]	1,755.97[A]	1,572.08[A]	1,127.07[A]	1,061.40[A]	858.86[A]	69
2015 June	909.59[A]	1,154.75[A]	1,223.83[A]	1,764.35[A]	1,806.19[A]	1,138.82[A]	1,043.36[A]	860.48[A]	69
2015 July	913.87[A]	1,151.50[A]	1,174.14[A]	1,707.48[A]	1,653.21[A]	1,141.88[A]	1,032.94[A]	868.09[A]	70
2015 August	906.46[A]	1,130.18[A]	1,205.83[A]	1,725.26[A]	1,700.13[A]	1,130.15[A]	1,014.75[A]	863.57[A]	70
2015 September	911.95[A]	1,144.29[A]	1,247.21[A]	1,708.33[A]	1,577.58[A]	1,129.23[A]	1,041.00[A]	866.01[A]	68
2015 October	913.09[A]	1,152.73[A]	1,269.45[A]	1,739.84[A]	1,614.48[A]	1,109.45[A]	1,077.46[A]	867.28[A]	68
2015 November	910.40[A]	1,154.79[A]	1,273.15[A]	1,799.40[A]	1,605.43[A]	1,117.30[A]	1,057.17[A]	862.79[A]	69
2015 December	925.59[A]	1,163.74[A]	1,331.62[A]	1,776.77[A]	1,567.11[A]	1,116.86[A]	1,055.00[A]	880.23[A]	71
2016 January	905.14[A]	1,152.15[A]	1,289.79[A]	1,900.85[A]	1,694.18[A]	1,120.10[A]	1,050.69[A]	858.73[A]	69
2016 February	913.43[A]	1,146.10[A]	1,321.72[A]	1,845.96[A]	1,645.40[A]	1,112.78[A]	1,046.51[A]	870.74[A]	71
2016 March	915.72[A]	1,152.94[A]	1,256.44[A]	1,881.80[A]	1,822.15[A]	1,116.38[A]	1,044.59[A]	870.51[A]	70
2016 April	920.79[A]	1,157.19[A]	1,280.93[A]	1,758.81[A]	1,860.00[A]	1,123.83[A]	1,093.66[A]	875.07[A]	71
2016 May	919.11[A]	1,149.32[A]	1,220.80[A]	1,734.56[A]	1,790.02[A]	1,116.13[A]	1,060.70[A]	875.66[A]	72

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

November 3, 2015
Provincial Medium Term
Forecast: 20153 Run: 16
Table 156 and 157

BRITISH COLUMBIA	2010	2011	2012	2013	2014	2015	2016	2017
Forecasted Single-Family Housing Starts (Units)	11,462	8,867	8,333	8,522	9,569	10,499	9,808	9,188
Forecast Percent Change	45.2	(22.6)	(6.0)	2.3	12.3	9.7	(6.6)	(6.3)
Forecasted Mult-Family Housing Starts (Units)	15,017	17,533	19,132	18,532	18,787	22,565	23,102	23,064
Forecast Percent Change	83.5	16.8	9.1	(3.1)	1.4	20.1	2.4	(0.2)
Forecast Housing Starts Total	26,479	26,400	27,465	27,054	28,356	33,064	32,910	32,252

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. 2006-2015 actual data
    b. 2016 seed year data
    c. 2017 forecast data
2. Percent Error
    a. 2006-2015 forecast, actual and percent error

2. HISTORIC AND FORECAST DATA TABLES

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

FEI Customer Counts

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Rate 1	809,468	825,262	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169	898,214	909,702
Rate 2	82,091	83,289	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076	86,396	87,714
Rate 3	5,360	5,290	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301	5,327	5,353
Rate 23	1,206	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724	1,742	1,760
Industrial	1,324	1,197	1,145	1,113	1,017	951	954	981	977	976	967	967
NGT	0	0	0	0	0	2	5	10	18	31	38	41
Total	899,450	916,341	929,114	937,261	946,574	953,943	942,872	953,295	964,971	979,277	992,684	1,005,537

FEI Customer Additions

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Rate 1	12,744	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	12,045	11,488
Rate 2	877	1,198	1,330	446	128	511	577	1,329	1,173	1,450	1,320	1,318
Rate 3	-122	-71	171	-31	37	-16	-104	-86	35	132	26	26
Rate 23	168	97	3	42	58	27	88	9	-7	202	18	18
Total	13,667	17,018	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	13,409	12,850

FEI Normalized Use Per Customer (Gjs)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Rate 1	95.2	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	83.3	82.2
Rate 2	319.3	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	330.5	328.4
Rate 3	3,449	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,532	3,477
Rate 23	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,209	5,227

FEI Energy (Pjs)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Rate 1	74.8	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	74.3	74.3
Rate 2	26.0	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0	28.3	28.5
Rate 3	18.3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2	18.8	18.6
Rate 23	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6	9.0	9.2
Industrial	81.4	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	80.3	82.1
Sub-Total	206.0	208.7	202.1	199.2	201.9	206.6	209.7	206.3	205.7	209.5	210.7	212.7
NGT	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	1.1	1.3	3.1
Total	206.0	208.7	202.1	199.2	201.9	206.7	209.9	206.6	206.5	210.6	212.1	215.8

[1]

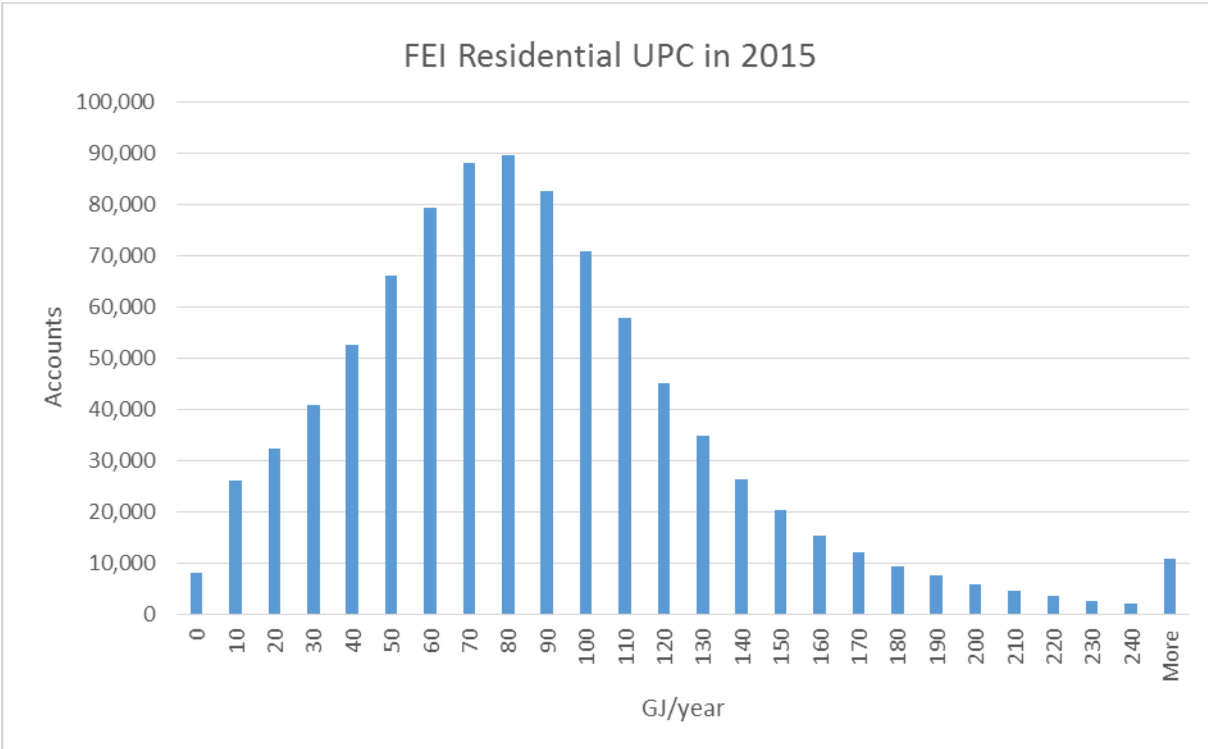
Table A2-2: FEI 2017 Industrial Forecast Demand by Region

Industrial	**2017 Forecast Demand By Region**
Mainland	59.7
Vancouver Island	22.4
Whistler	0.0
Total	**82.1**

[2]

[1] Historical industrial tables do not include Burrard Thermal demand.

1 **Figure A2-1: FEI Residential Customers UPC in 2015**



2

[2] Does not include NGT forecast demand.

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 SUMMARY OF RESULTS

Based on research completed for the Forecasting Directives (Appendix A4) FEI believes a reasonable performance target for the residential and commercial components of the demand forecast is a mean average percent error (MAPE) of 4%. The following data is summarized from data found in section 3.5 of this appendix

As shown in the following table, the 10 year MAPE of the consolidated FEI residential forecast is 2.1%, slightly more than half of the 4% residential target. The 2015 performance was significantly better than the 10 year MAPE at just 1.3%.

Table A2-3: Residential Demand Forecast Performance

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. MAPE
FEI Rate Schedule 1											
Forecast	77.7	78.4	77.2	73.8	74.3	73.8	74.7	74.6	74.2	73.1	
Actual	74.8	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	
Error = (ACT-FCST)	(2.9)	(3.0)	(3.5)	1.0	0.7	0.1	(0.2)	(1.9)	(1.0)	1.0	
Percent Error = (Error/ACT)	-3.9%	-4.0%	-4.7%	1.3%	0.9%	0.1%	-0.3%	-2.6%	-1.4%	1.3%	
Abs. Precent Error	3.9%	4.0%	4.7%	1.3%	0.9%	0.1%	0.3%	2.6%	1.4%	1.3%	2.1%

As shown in the following table the 10 year MAPE of the consolidated FEI commercial demand forecast is 2.0%, exactly half of the 4% commercial target. The 2015 performance of the commercial demand forecast was the second best in the last decade, at just 0.3%.

Table A2-4: Commercial Demand Forecast Performance

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. MAPE
FEI Commercial											
Forecast	49.4	50.2	51.9	49.0	53.2	53.8	53.2	53.5	56.3	55.6	
Actual	49.8	51.4	51.7	53.0	52.5	54.0	54.7	53.6	54.0	55.8	
Error = (ACT-FCST)	0.4	1.2	(0.2)	4.0	(0.7)	0.2	1.5	0.1	(2.3)	0.2	
Percent Error = (Error/ACT)	0.8%	2.3%	-0.4%	7.5%	-1.3%	0.4%	2.7%	0.2%	-4.3%	0.3%	
Abs. Precent Error	0.8%	2.3%	0.4%	7.5%	1.3%	0.4%	2.7%	0.2%	4.3%	0.3%	2.0%

FEI believes these two tables are critical in evaluating the performance of the demand forecast because these results can be compared to industry averages. Consistent with past filings the following pages contain the remainder of the detailed data.

3.2 *AMALGAMATED NET CUSTOMERS*

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	814,441	828,303	842,919	846,375	849,539	857,592	870,980	880,331	866,852	883,371
Actual	809,468	825,262	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169
Error = (ACT-FCST)	(4,973)	(3,041)	(6,336)	(2,069)	3,953	2,811	(16,930)	(17,142)	6,809	2,798
Percent Error = (Error/ACT)	-0.6%	-0.4%	-0.8%	-0.2%	0.5%	0.3%	-2.0%	-2.0%	0.8%	0.3%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	81,855	82,591	83,957	84,667	86,383	87,262	85,482	85,627	81,923	84,651
Actual	82,091	83,289	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076
Error = (ACT-FCST)	236	698	662	398	(1,190)	(1,558)	(4,359)	(3,175)	1,702	425
Percent Error = (Error/ACT)	0.3%	0.8%	0.8%	0.5%	-1.4%	-1.8%	-5.4%	-3.9%	2.0%	0.5%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	5,345	4,942	5,116	5,316	5,671	5,785	5,553	5,597	5,147	5,117
Actual	5,360	5,290	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301
Error = (ACT-FCST)	15	348	344	113	(205)	(334)	(333)	(463)	22	184
Percent Error = (Error/ACT)	0%	6.6%	6.3%	2.1%	-3.8%	-6.1%	-6.4%	-9.0%	0.4%	3.5%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	1,047	1,313	1,423	1,426	1,319	1,328	1,526	1,586	1,634	1,552
Actual	1,206	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724
Error = (ACT-FCST)	159	(10)	(117)	(78)	87	105	(6)	(57)	(112)	172
Percent Error = (Error/ACT)	13.2%	-0.8%	-9.0%	-5.8%	6.2%	7.3%	-0.4%	-3.7%	-7.4%	10.0%

3.3 AMALGAMATED NET CUSTOMER ADDITIONS

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	15,829	16,267	14,603	9,827	7,012	7,724	8,984	9,352	6,647	9,710
Actual	12,744	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508
Error = (ACT-FCST)	(3,085)	(473)	(3,282)	(2,104)	2,174	(813)	(2,613)	(213)	3,825	2,798
Percent Error = (Error/ACT)	-24.2%	-3.0%	-29.0%	-27.2%	23.7%	-11.8%	-41.0%	-2.3%	36.5%	22.4%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	675	588	796	618	830	877	145	145	411	1,026
Actual	877	1,198	1,330	446	128	511	577	1,329	1,173	1,450
Error = (ACT-FCST)	202	610	534	(172)	(702)	(366)	432	1,184	762	424
Percent Error = (Error/ACT)	23.0%	50.9%	40.2%	-38.6%	-548.4%	-71.6%	74.9%	89.1%	65.0%	29.2%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	(4)	(284)	14	14	105	114	44	44	4	(52)
Actual	(122)	(71)	171	(31)	37	(16)	(104)	(86)	35	132
Error = (ACT-FCST)	(118)	213	157	(45)	(68)	(130)	(148)	(130)	31	184
Percent Error = (Error/ACT)	96.7%	-300.0%	91.8%	145.2%	-183.8%	812.5%	142.3%	151.2%	88.6%	139.4%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	9	147	70	53	9	9	60	60	57	30
Actual	168	97	3	42	58	27	88	9	(7)	202
Error = (ACT-FCST)	159	(50)	(67)	(11)	49	18	28	(51)	(64)	172
Percent Error = (Error/ACT)	94.6%	-51.5%	-2233.3%	-26.2%	84.5%	66.7%	31.8%	-566.7%	914.3%	85.1%

3.4 AMALGAMATED USE PER CUSTOMER

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	96.5	95.7	92.4	87.7	87.9	86.5	86.3	85.2	86.0	83.1
Actual	95.2	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4
Error = (ACT-FCST)	(1.3)	(3.5)	(3.6)	1.4	0.5	(0.2)	1.3	(0.5)	(1.8)	1.3
Percent Error = (Error/ACT)	-1.4%	-3.8%	-4.1%	1.6%	0.6%	-0.2%	1.5%	-0.6%	-2.1%	1.5%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	311.1	318.7	325.4	309.0	320.5	320.2	315.0	314.5	340.0	333.7
Actual	319.3	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6
Error = (ACT-FCST)	8.2	3.4	(7.2)	16.1	(4.3)	(2.5)	26.2	17.1	(9.4)	(1.1)
Percent Error = (Error/ACT)	2.6%	1.1%	-2.3%	5.0%	-1.4%	-0.8%	7.7%	5.2%	-2.8%	-0.3%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	3,507	3,527	3,573	3,164	3,496	3,487	3,450	3,435	3,872	3,754
Actual	3,449	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587
Error = (ACT-FCST)	(58)	38	(34)	316	(11)	101	234	175	(299)	(167)
Percent Error = (Error/ACT)	-1.7%	1.1%	-1.0%	9.1%	-0.3%	2.8%	6.4%	4.8%	-8.4%	-4.7%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	4,979	4,796	4,850	4,391	4,680	4,680	4,901	4,927	5,546	5,309
Actual	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174
Error = (ACT-FCST)	(293)	(18)	(152)	495	170	458	337	222	(286)	(135)
Percent Error = (Error/ACT)	-6.3%	-0.4%	-3.2%	10.1%	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.6%

3.5 *AMALGAMATED DEMAND*

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	77.7	78.4	77.2	73.8	74.3	73.8	74.7	74.6	74.2	73.1
Actual	74.8	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1
Error = (ACT-FCST)	(2.9)	(3.0)	(3.5)	1.0	0.7	0.1	(0.2)	(1.9)	(1.0)	1.0
Percent Error = (Error/ACT)	-3.9%	-4.0%	-4.7%	1.3%	0.9%	0.1%	-0.3%	-2.6%	-1.4%	1.3%

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	25.3	26.2	27.1	26.1	27.5	27.7	26.9	26.9	27.7	28.1
Actual	26.0	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0
Error = (ACT-FCST)	0.7	0.5	(0.5)	1.4	(0.6)	(0.6)	0.7	0.1	(0.2)	(0.1)
Percent Error = (Error/ACT)	2.7%	1.9%	-1.9%	5.1%	-2.2%	-2.2%	2.5%	0.4%	-0.7%	-0.4%

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	18.9	18.3	18.2	16.8	19.6	19.9	19.1	19.1	19.9	19.2
Actual	18.3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2
Error = (ACT-FCST)	(0.6)	0.5	0.7	2.2	(0.6)	(0.4)	0.2	(0.4)	(1.4)	(0.0)
Percent Error = (Error/ACT)	-3.3%	2.7%	3.7%	11.6%	-3.2%	-2.1%	1.0%	-2.1%	-7.6%	-0.2%

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	5.2	5.7	6.6	6.1	6.1	6.2	7.2	7.5	8.7	8.3
Actual	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6
Error = (ACT-FCST)	0.3	0.2	(0.4)	0.4	0.5	1.2	0.6	0.4	(0.7)	0.3
Percent Error = (Error/ACT)	5.5%	3.4%	-6.5%	6.2%	7.6%	16.2%	7.7%	5.1%	-8.7%	3.5%

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Commercial										
Forecast	49.4	50.2	51.9	49.0	53.2	53.8	53.2	53.5	56.3	55.6
Actual	49.8	51.4	51.7	53.0	52.5	54.0	54.7	53.6	54.0	55.8
Error = (ACT-FCST)	0.4	1.2	(0.2)	4.0	(0.7)	0.2	1.5	0.1	(2.3)	0.2
Percent Error = (Error/ACT)	0.8%	2.3%	-0.4%	7.5%	-1.3%	0.4%	2.7%	0.2%	-4.3%	0.3%

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Industrial*										
Forecast	85.0	82.3	75.1	71.9	73.2	71.3	72.1	72.1	86.2	76.4
Actual	81.4	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6
Error = (ACT-FCST)	(3.6)	(0.5)	1.5	(0.5)	1.2	7.5	8.5	8.0	(7.6)	3.2
Percent Error = (Error/ACT)	-4.4%	-0.6%	2.0%	-0.7%	1.6%	9.5%	10.5%	10.0%	-9.7%	4.0%

Demand,PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
FEI *										
Forecast	212.1	210.9	204.2	194.7	200.7	198.9	200.0	200.2	216.7	205.2
Actual	206.0	208.6	202.0	199.2	201.9	206.7	209.8	206.4	205.8	209.5
Error = (ACT-FCST)	-6.1	-2.3	-2.2	4.5	1.2	7.8	9.8	6.2	-10.9	4.3
Percent Error = (Error/ACT)	-3.0%	-1.1%	-1.1%	2.3%	0.6%	3.8%	4.7%	3.0%	-5.3%	2.1%

* Does not include NGT and Burrard Thermal

3.6 *MAINLAND NET CUSTOMERS*

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	732,228	744,400	755,539	755,803	757,161	762,460	773,231	780,005	768,622	780,972
Actual	728,951	740,954	748,913	753,735	760,559	765,553	759,712	766,668	774,083	782,914
Error = (ACT-FCST)	(3,277)	(3,446)	(6,626)	(2,068)	3,398	3,093	(13,519)	(13,337)	5,461	1,942
Percent Error = (Error/ACT)	-0.4%	-0.5%	-0.9%	-0.3%	0.4%	0.4%	-1.8%	-1.7%	0.7%	0.2%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	73,200	74,019	75,037	75,685	77,204	77,954	76,126	76,175	72,922	75,315
Actual	73,515	74,579	75,701	75,986	76,028	76,437	72,235	73,480	74,464	75,451
Error = (ACT-FCST)	315	560	664	301	(1,176)	(1,517)	(3,891)	(2,695)	1,542	136
Percent Error = (Error/ACT)	0.4%	0.8%	0.9%	0.4%	-1.5%	-2.0%	-5.4%	-3.7%	2.1%	0.2%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	4,742	4,332	4,514	4,715	5,083	5,191	4,962	5,002	4,577	4,560
Actual	4,769	4,700	4,869	4,841	4,882	4,863	4,675	4,598	4,625	4,671
Error = (ACT-FCST)	27	368	355	126	(201)	(328)	(287)	(404)	48	111
Percent Error = (Error/ACT)	0.6%	7.8%	7.3%	2.6%	-4.1%	-6.7%	-6.1%	-8.8%	1.0%	2.4%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	1,047	1,313	1,423	1,426	1,319	1,328	1,526	1,586	1,634	1,552
Actual	1,206	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,573
Error = (ACT-FCST)	159	(10)	(117)	(78)	87	105	(6)	(57)	(112)	21
Percent Error = (Error/ACT)	13.2%	-0.8%	-9.0%	-5.8%	6.2%	7.3%	-0.4%	-3.7%	-7.4%	1.3%

3.7 *MAINLAND NET CUSTOMER ADDITIONS*

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	12,048	12,764	11,094	6,410	4,777	4,983	6,507	6,774	4,594	6,889
Actual	8,927	12,003	7,959	4,822	6,824	4,994	4,475	6,956	7,415	8,831
Error = (ACT-FCST)	(3,121)	(761)	(3,135)	(1,588)	2,047	11	(2,032)	182	2,821	1,942
Percent Error = (Error/ACT)	-35.0%	-6.3%	-39.4%	-32.9%	30.0%	0.2%	-45.4%	2.6%	38.0%	22.0%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	622	523	626	480	713	750	49	49	331	851
Actual	937	1,064	1,122	285	42	409	325	1,245	984	987
Error = (ACT-FCST)	315	541	496	(195)	(671)	(341)	276	1,196	653	136
Percent Error = (Error/ACT)	33.6%	50.8%	44.2%	-68.4%	-1597.6%	-83.4%	84.9%	96.1%	66.4%	13.7%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	(7)	(288)	8	7	101	108	40	40	-	(65)
Actual	(115)	(69)	169	(28)	41	(19)	(144)	(77)	27	46
Error = (ACT-FCST)	(108)	219	161	(35)	(60)	(127)	(184)	(117)	27	111
Percent Error = (Error/ACT)	93.9%	-317.4%	95.3%	125.0%	-146.3%	668.4%	127.8%	151.9%	100.0%	241.3%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	9	147	70	53	9	9	60	60	57	30
Actual	168	97	3	42	58	27	88	9	(7)	51
Error = (ACT-FCST)	159	(50)	(67)	(11)	49	18	28	(51)	(64)	21
Percent Error = (Error/ACT)	94.6%	-51.5%	-2233.3%	-26.2%	84.5%	66.7%	31.8%	-566.7%	914.3%	41.2%

3.8 *MAINLAND USE PER CUSTOMER*

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	101	100	96	91	92	90	91	90	91	88
Actual	97	96	93	93	93	90	92	89	89	89
Error = (ACT-FCST)	(4)	(4)	(4)	2	1	0	1	(1)	(2)	1
Percent Error = (Error/ACT)	-3.9%	-4.0%	-3.9%	2.4%	1.0%	0.1%	1.5%	-0.7%	-2.1%	0.7%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	307	314	322	303	318	318	308	306	334	329
Actual	314	317	312	321	311	314	338	330	330	330
Error = (ACT-FCST)	7	2	(10)	17	(7)	(4)	30	23	(3)	1
Percent Error = (Error/ACT)	2.3%	0.7%	-3.1%	5.4%	-2.1%	-1.3%	8.8%	7.0%	-1.0%	0.2%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	3,391	3,394	3,429	2,976	3,346	3,347	3,334	3,316	3,769	3,599
Actual	3,314	3,426	3,420	3,372	3,370	3,484	3,566	3,517	3,529	3,524
Error = (ACT-FCST)	(77)	32	(9)	396	24	137	232	201	(240)	(75)
Percent Error = (Error/ACT)	-2.3%	0.9%	-0.3%	11.7%	0.7%	3.9%	6.5%	5.7%	-6.8%	-2.1%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	4,979	4,796	4,850	4,391	4,680	4,680	4,901	4,927	5,546	5,309
Actual	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,157
Error = (ACT-FCST)	(293)	(18)	(152)	495	170	458	337	222	(286)	(152)
Percent Error = (Error/ACT)	-6.3%	-0.4%	-3.2%	10.1%	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.9%

3.9 *MAINLAND DEMAND*

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	72.9	73.6	72.0	68.5	69.2	68.6	69.9	69.8	69.5	68.5
Actual	70.0	70.6	68.8	70.0	70.0	68.9	69.8	68.1	68.5	68.9
Error = (ACT-FCST)	2.9	2.9	3.2	(1.5)	(0.9)	(0.4)	0.1	1.7	1.0	(0.4)
Percent Error = (Error/ACT)	4.0%	4.0%	4.4%	-2.2%	-1.3%	-0.5%	0.2%	2.5%	1.5%	-0.6%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	22.3	23.1	24.0	22.9	24.4	24.6	23.4	23.3	24.2	24.7
Actual	22.9	23.5	23.4	24.3	23.6	23.9	24.3	23.9	24.5	24.6
Error = (ACT-FCST)	0.6	0.4	(0.6)	1.4	(0.8)	(0.7)	0.9	0.6	0.2	(0.0)
Percent Error = (Error/ACT)	2.7%	1.6%	-2.7%	5.7%	-3.2%	-3.0%	3.6%	2.5%	0.9%	-0.2%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	16.3	15.5	15.5	14.0	16.8	17.2	16.5	16.5	17.3	16.4
Actual	15.6	16.1	16.3	16.5	16.4	16.9	16.7	16.3	16.3	16.5
Error = (ACT-FCST)	(0.7)	0.6	0.8	2.5	(0.4)	(0.3)	0.2	(0.2)	(1.0)	0.0
Percent Error = (Error/ACT)	-4%	4%	5%	15%	-2%	-2%	1%	-1%	-6%	0%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast	5.2	5.7	6.6	6.1	6.1	6.2	7.2	7.5	8.7	8.3
Actual	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.0
Error = (ACT-FCST)	0.3	0.2	(0.4)	0.4	0.5	1.2	0.6	0.4	(0.7)	(0.3)
Percent Error = (Error/ACT)	5%	3%	-6%	6%	8%	16%	8%	5%	-9%	-3%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Commercial										
Forecast	43.8	44.3	46.1	43.0	47.3	48.0	47.1	47.3	50.2	49.3
Actual	44.0	45.5	45.9	47.3	46.6	48.2	48.8	48.1	48.8	49.1
Error = (ACT-FCST)	0.2	1.2	(0.2)	4.3	(0.7)	0.2	1.7	0.8	(1.5)	(0.3)
Percent Error = (Error/ACT)	0.5%	2.6%	-0.5%	9.1%	-1.4%	0.4%	3.4%	1.6%	-3.0%	-0.5%

3.10 VANCOUVER ISLAND NET CUSTOMERS

3.10.1 Traditional Rate Schedules

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS									
Forecast	80,080	81,732	85,256	88,394	90,106	92,811	95,460	98,023	95,858
Actual	78,453	82,210	85,536	88,321	90,671	92,554	92,067	94,173	97,162
Error = (ACT-FCST)	(1,627)	478	280	(73)	565	(257)	(3,393)	(3,850)	1,304
Percent Error = (Error/ACT)	-2.1%	0.6%	0.3%	-0.1%	0.6%	-0.3%	-3.7%	-4.1%	1.3%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS									
Forecast	779	807	849	848	882	887	954	980	1,014
Actual	785	821	868	876	902	939	959	1,000	1,032
Error = (ACT-FCST)	6	14	19	28	20	52	5	20	18
Percent Error = (Error/ACT)	0.8%	1.7%	2.2%	3.2%	2.2%	5.5%	0.5%	2.0%	1.7%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF									
Forecast	7	7	6	6	6	6	6	6	6
Actual	6	5	6	6	6	14	6	6	4
Error = (ACT-FCST)	(1)	(2)	-	-	-	8	-	-	(2)
Percent Error = (Error/ACT)	-16.7%	-40.0%	0.0%	0.0%	0.0%	57.1%	0.0%	0.0%	-50.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF									
Forecast	9	8	9	8	8	8	8	8	8
Actual	9	8	8	8	8	8	8	8	7
Error = (ACT-FCST)	-	-	(1)	-	-	-	-	-	(1)
Percent Error = (Error/ACT)	0.0%	0.0%	-12.5%	0.0%	0.0%	0.0%	0.0%	0.0%	-14.3%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C									
Forecast	1,503	1,505	1,469	1,467	1,356	1,361	1,396	1,408	1,308
Actual	1,474	1,454	1,446	1,360	1,372	1,360	1,263	1,264	1,264
Error = (ACT-FCST)	(29)	(51)	(23)	(107)	16	(1)	(133)	(144)	(44)
Percent Error = (Error/ACT)	-2.0%	-3.5%	-1.6%	-7.9%	1.2%	-0.1%	-10.5%	-11.4%	-3.5%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C									
Forecast	553	562	546	536	526	531	517	517	471
Actual	543	530	523	526	517	514	433	435	440
Error = (ACT-FCST)	(10)	(32)	(23)	(10)	(9)	(17)	(84)	(82)	(31)
Percent Error = (Error/ACT)	-1.8%	-6.0%	-4.4%	-1.9%	-1.7%	-3.3%	-19.4%	-18.9%	-7.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C									
Forecast	135	130	141	144	121	124	121	121	127
Actual	140	142	146	124	121	119	133	95	100
Error = (ACT-FCST)	5	12	5	(20)	-	(5)	12	(26)	(27)
Percent Error = (Error/ACT)	3.6%	8.5%	3.4%	-16.1%	0.0%	-4.2%	9.0%	-27.4%	-27.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C									
Forecast	4,141	4,058	4,426	4,531	5,180	5,287	5,202	5,247	4,908
Actual	4,178	4,331	4,509	5,068	5,112	5,168	4,837	5,004	5,136
Error = (ACT-FCST)	37	273	83	537	(68)	(119)	(365)	(243)	228
Percent Error = (Error/ACT)	0.9%	6.3%	1.8%	10.6%	-1.3%	-2.3%	-7.5%	-4.9%	4.4%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C									
Forecast	1,832	1,815	1,807	1,759	1,405	1,410	1,451	1,463	1,420
Actual	1,773	1,741	1,728	1,415	1,427	1,434	1,382	1,394	1,414
Error = (ACT-FCST)	(59)	(74)	(79)	(344)	22	24	(69)	(69)	(6)
Percent Error = (Error/ACT)	-3.3%	-4.3%	-4.6%	-24.3%	1.5%	1.7%	-5.0%	-4.9%	-0.4%

3.10.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the Vancouver Island 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.

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	80,080	81,732	85,256	88,394	90,106	92,811	95,460	98,023	95,858	99,921
Actual	78,453	82,210	85,536	88,321	90,671	92,554	92,067	94,173	97,162	100,747
Error = (ACT-FCST)	(1,627)	478	280	(73)	565	(257)	(3,393)	(3,850)	1,304	826
Percent Error = (Error/ACT)	-2%	1%	0%	0%	1%	0%	-4%	-4%	1%	1%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	8,377	8,304	8,666	8,718	8,917	9,042	9,081	9,172	8,710	9,047
Actual	8,332	8,461	8,658	8,815	8,900	8,981	8,613	8,691	8,875	9,330
Error = (ACT-FCST)	(45)	157	(8)	97	(17)	(61)	(468)	(481)	165	283
Percent Error = (Error/ACT)	-0.54%	1.86%	-0.09%	1.10%	-0.19%	-0.68%	-5.43%	-5.53%	1.86%	3.03%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	540	548	545	539	527	532	532	536	509	497
Actual	535	531	533	527	525	527	484	476	484	582
Error = (ACT-FCST)	(5)	(17)	(12)	(12)	(2)	(5)	(48)	(60)	(25)	85
Percent Error = (Error/ACT)	-0.93%	-3.20%	-2.25%	-2.28%	-0.38%	-0.95%	-9.92%	-12.61%	-5.17%	14.60%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										141
Error = (ACT-FCST)										141
Percent Error = (Error/ACT)										

3.11 *VANCOUVER ISLAND NET CUSTOMER ADDITIONS*

3.11.1 Traditional Rate Schedules

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS									
Forecast	3,781	3,428	3,479	3,367	2,200	2,705	2,463	2,564	2,001
Actual	3,798	3,757	3,326	2,785	2,350	1,883	1,845	2,106	2,989
Error = (ACT-FCST)	17	329	(153)	(582)	150	(822)	(618)	(458)	988
Percent Error = (Error/ACT	0.4%	8.8%	-4.6%	-20.9%	6.4%	-43.7%	-33.5%	-21.7%	33.1%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS									
Forecast	5	5	15	15	5	5	26	26	32
Actual	(1)	36	47	8	26	37	35	41	32
Error = (ACT-FCST)	(6)	31	32	(7)	21	32	9	15	0
Percent Error = (Error/ACT	600.0%	86.1%	68.1%	-87.5%	80.8%	86.5%	25.7%	36.6%	0.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF									
Forecast	-	-	-	-	-	-	-	-	-
Actual	(1)	(1)	1	-	-	8	-	-	(2)
Error = (ACT-FCST)	(1)	(1)	1	0	0	8	0	0	(2)
Percent Error = (Error/ACT	100.0%	100.0%	100.0%			100.0%			100.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF									
Forecast	-	-	-	-	-	-	-	-	-
Actual	1	(1)	-	-	-	-	-	-	(1)
Error = (ACT-FCST)	1	(1)	0	0	0	0	0	0	(1)
Percent Error = (Error/ACT	100.0%	100.0%							100.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C									
Forecast	8	8	10	6	5	5	12	12	-
Actual	(19)	(20)	(8)	(86)	12	(12)	64	1	-
Error = (ACT-FCST)	(27)	(28)	(18)	(92)	7	(17)	52	(11)	0
Percent Error = (Error/ACT	142.1%	140.0%	225.0%	107.0%	58.3%	141.7%	81.3%	-1100.0%	

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C									
Forecast	3	4	5	3	5	5	-	-	-
Actual	(9)	(13)	(7)	3	(9)	(3)	58	2	5
Error = (ACT-FCST)	(12)	(17)	(12)	0	(14)	(8)	58	2	5
Percent Error = (Error/ACT	133.3%	130.8%	171.4%	0.0%	155.6%	266.7%	100.0%	100.0%	100.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C									
Forecast	1	-	1	1	-	3	-	-	-
Actual	11	2	4	(22)	(3)	(2)	(33)	(38)	-
Error = (ACT-FCST)	10	2	3	(23)	(3)	(5)	(33)	(38)	0
Percent Error = (Error/ACT	90.9%	100.0%	75.0%	104.5%	100.0%	250.0%	100.0%	100.0%	

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C									
Forecast	29	30	120	100	100	107	45	45	33
Actual	16	153	178	559	44	56	10	167	132
Error = (ACT-FCST)	(13)	123	58	459	(56)	(51)	(35)	122	99
Percent Error = (Error/ACT	-81.3%	80.4%	32.6%	82.1%	-127.3%	-91.1%	-350.0%	73.1%	75.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C									
Forecast	10	10	20	8	5	5	12	12	11
Actual	(50)	(32)	(13)	(313)	12	7	36	12	20
Error = (ACT-FCST)	(60)	(42)	(33)	(321)	7	2	24	0	9
Percent Error = (Error/ACT	120.0%	131.3%	253.8%	102.6%	58.3%	28.6%	66.7%	0.0%	45.0%

3.11.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the Vancouver Island 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.

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	3,781	3,428	3,479	3,367	2,200	2,705	2,463	2,564	2,001	2,759
Actual	3,798	3,757	3,326	2,785	2,350	1,883	1,845	2,106	2,989	3,583
Error = (ACT-FCST)	17	329	(153)	(582)	150	(822)	(618)	(458)	988	824
Percent Error = (Error/ACT)	0.4%	8.8%	-4.6%	-20.9%	6.4%	-43.7%	-33.5%	-21.7%	33.1%	23.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	53	53	165	128	116	125	91	91	71	171
Actual	(49)	129	197	157	85	81	251	78	184	453
Error = (ACT-FCST)	(102)	76	32	29	(31)	(44)	160	(13)	113	282
Percent Error = (Error/ACT)	207.6%	58.6%	16.3%	18.3%	-36.4%	-54.1%	63.8%	-16.4%	61.1%	62.2%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	3	3	6	4	4	5	4	4	4	13
Actual	(3)	(4)	2	(6)	(2)	2	39	(8)	8	98
Error = (ACT-FCST)	(6)	(7)	(4)	(10)	(6)	(3)	35	(12)	4	85
Percent Error = (Error/ACT)	200.0%	175.0%	-200.0%	166.7%	300.0%	-150.0%	89.7%	150.0%	50.0%	86.6%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										141
Error = (ACT-FCST)										141
Percent Error = (Error/ACT)										

3.12 VANCOUVER ISLAND USE PER CUSTOMER

3.12.1 Traditional Rate Schedules

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS									
Forecast	58.9	57.6	59.3	58.6	55.0	54.9	48.6	46.9	45.0
Actual	60.2	57.0	56.1	53.5	52.5	51.8	49.5	47.3	47.1
Error = (ACT-FCST)	1.3	(0.6)	(3.2)	(5.1)	(2.5)	(3.1)	0.9	0.5	2.1
Percent Error = (Error/ACT)	2.2%	-1.0%	-5.7%	-9.5%	-4.7%	-5.9%	1.8%	1.0%	4.5%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS									
Forecast	1,326.0	1,393.0	1,389.0	1,364.0	1,262.0	1,262.0	1,264.0	1,244.9	1,324.8
Actual	1,387.1	1,366.7	1,296.5	1,260.9	1,300.8	1,343.3	1,245.7	1,151.7	1,073.9
Error = (ACT-FCST)	61.1	(26.3)	(92.5)	(103.1)	38.8	81.3	(18.3)	(93.2)	(250.9)
Percent Error = (Error/ACT)	4.4%	-1.9%	-7.1%	-8.2%	3.0%	6.1%	-1.5%	-8.1%	-23.4%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF									
Forecast	37,532.0	38,968.0	25,000.0	29,245.0	22,061.0	22,061.0	10,189.1	10,189.1	20,532.0
Actual	46,053.3	29,244.5	22,061.2	19,584.7	20,420.0	8,779.5	20,532.0	19,181.6	18,009.4
Error = (ACT-FCST)	8521.3	(9723.5)	(2938.8)	(9660.3)	(1641.0)	(13281.5)	10342.9	8992.5	(2522.6)
Percent Error = (Error/ACT)	18.5%	-33.2%	-13.3%	-49.3%	-8.0%	-151.3%	50.4%	46.9%	-14.0%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF									
Forecast	12,481.0	19,764.0	18,433.0	14,964.0	15,062.0	15,062.0	14,051.3	14,051.3	10,547.2
Actual	17,102.6	14,963.7	16,344.4	12,197.2	13,945.9	14,938.4	10,547.1	10,889.8	11,367.4
Error = (ACT-FCST)	4621.6	(4800.3)	(2088.6)	(2766.9)	(1116.1)	(123.6)	(3504.1)	(3161.5)	820.2
Percent Error = (Error/ACT)	27.0%	-32.1%	-12.8%	-22.7%	-8.0%	-0.8%	-33.2%	-29.0%	7.2%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C									
Forecast	898.0	907.0	916.0	930.0	981.0	981.0	1,048.7	1,074.6	1,069.4
Actual	903.2	943.1	951.8	979.7	997.1	963.4	1,060.0	980.8	967.2
Error = (ACT-FCST)	5.2	36.1	35.8	49.7	16.1	(17.6)	11.3	(93.8)	(102.2)
Percent Error = (Error/ACT)	0.6%	3.8%	3.8%	5.1%	1.6%	-1.8%	1.1%	-9.6%	-10.6%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C									
Forecast	2,320.0	2,343.0	2,341.0	2,362.0	2,649.0	2,649.0	2,591.2	2,641.4	3,074.2
Actual	2,295.4	2,406.0	2,359.4	2,430.5	2,490.4	2,475.0	2,935.5	2,728.2	2,623.3
Error = (ACT-FCST)	(24.6)	63.0	18.4	68.4	(158.6)	(174.0)	344.2	86.8	(450.9)
Percent Error = (Error/ACT)	-1.1%	2.6%	0.8%	2.8%	-6.4%	-7.0%	11.7%	3.2%	-17.2%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C									
Forecast	16,636.0	17,951.0	18,188.0	17,694.0	19,699.0	19,699.0	16,342.0	16,342.0	14,285.7
Actual	17,378.9	17,694.3	16,520.9	15,793.3	16,342.2	17,121.2	14,625.1	14,890.6	11,494.3
Error = (ACT-FCST)	742.9	(256.7)	(1667.1)	(1900.7)	(3356.8)	(2577.8)	(1716.9)	(1451.4)	(2791.4)
Percent Error = (Error/ACT)	4.3%	-1.5%	-10.1%	-12.0%	-20.5%	-15.1%	-11.7%	-9.7%	-24.3%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C									
Forecast	66.0	67.0	73.0	80.0	79.0	79.0	110.1	114.7	105.8
Actual	75.1	90.7	102.6	110.1	101.1	96.8	109.5	108.0	107.5
Error = (ACT-FCST)	9.1	23.7	29.6	30.1	22.1	17.8	(0.6)	(6.7)	1.7
Percent Error = (Error/ACT)	12.2%	26.1%	28.8%	27.3%	21.9%	18.4%	-0.5%	-6.2%	1.6%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C									
Forecast	295.0	295.0	307.0	313.0	345.0	345.0	347.0	355.5	370.2
Actual	313.8	310.3	313.2	325.4	330.2	320.3	354.8	323.3	321.7
Error = (ACT-FCST)	18.8	15.3	6.2	12.4	(14.8)	(24.7)	7.7	(32.2)	(48.5)
Percent Error = (Error/ACT)	6.0%	4.9%	2.0%	3.8%	-4.5%	-7.7%	2.2%	-10.0%	-15.1%

3.12.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the Vancouver Island 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.

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	58.8	57.7	59.3	58.6	55.0	54.9	48.6	46.9	45.0	44.0
Actual	60.2	57.0	56.1	53.5	52.5	51.8	49.5	47.3	47.1	50.5
Error = (ACT-FCST)	1.4	(0.7)	(3.2)	(5.1)	(2.5)	(3.1)	0.9	0.4	2.1	6.5
Percent Error = (Error/ACT)	2.3%	-1.2%	-5.7%	-9.5%	-4.8%	-6.0%	1.8%	0.8%	4.5%	12.9%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	344.0	356.0	353.0	354.0	340.0	337.0	365.0	372.0	390.0	372.0
Actual	361.0	366.0	365.0	361.0	351.0	345.0	369.0	344.0	328.0	346.0
Error = (ACT-FCST)	17.0	10.0	12.0	7.0	11.0	8.0	4.0	(28.0)	(62.0)	(26.0)
Percent Error = (Error/ACT)	4.7%	2.7%	3.3%	1.9%	3.1%	2.3%	1.1%	-8.1%	-18.9%	-7.5%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	6,451.0	6,512.0	6,499.0	6,454.0	6,295.0	6,349.0	6,351.0	6,398.0	5,896.0	5,896.0
Actual	4,437.0	4,631.0	4,488.0	4,421.0	4,435.0	4,460.0	4,820.0	4,431.0	3,901.0	3,894.0
Error = (ACT-FCST)	(2014.0)	(1881.0)	(2011.0)	(2033.0)	(1860.0)	(1889.0)	(1531.0)	(1967.0)	(1995.0)	(2002.0)
Percent Error = (Error/ACT)	-45.4%	-40.6%	-44.8%	-46.0%	-41.9%	-42.4%	-31.8%	-44.4%	-51.1%	-51.4%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										5,636.0
Error = (ACT-FCST)										
Percent Error = (Error/ACT)										

3.13 *VANCOUVER ISLAND DEMAND*

3.13.1 Traditional Rate Schedules

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS									
Forecast	4.6	4.6	4.9	5.1	4.9	5.0	4.6	4.5	4.3
Actual	4.6	4.6	4.7	4.6	4.7	4.7	4.5	4.4	4.5
Error = (ACT-FCST)	-	-	(0.2)	(0.5)	(0.2)	(0.3)	(0.1)	(0.1)	0.2
Percent Error = (Error/ACT)	0.0%	0.0%	-4.3%	-10.9%	-4.3%	-6.4%	-2.2%	-2.3%	4.4%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS									
Forecast	1.0	1.1	1.2	1.1	1.1	1.1	1.2	1.2	1.3
Actual	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.1	1.1
Error = (ACT-FCST)	0.1	(0.0)	(0.1)	(0.0)	0.0	0.1	(0.0)	(0.1)	(0.2)
Percent Error = (Error/ACT)	5.7%	-1.2%	-6.8%	-4.1%	4.0%	9.8%	-0.2%	-5.4%	-17.3%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF									
Forecast	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Actual	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Error = (ACT-FCST)	0.0	(0.1)	(0.0)	(0.1)	(0.0)	(0.0)	0.1	0.0	(0.1)
Percent Error = (Error/ACT)	4.4%	-65.9%	-13.3%	-49.3%	-8.0%	-7.7%	50.4%	37.6%	-71.0%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF									
Forecast	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Actual	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0
Percent Error = (Error/ACT)	26.1%	-18.0%	-26.9%	-22.7%	-8.0%	-0.8%	-33.2%	-29.0%	2.9%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C									
Forecast	1.3	1.3	1.3	1.4	1.3	1.3	1.5	1.5	1.4
Actual	1.3	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2
Error = (ACT-FCST)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.1)
Percent Error = (Error/ACT)	-1.1%	2.1%	2.7%	1.1%	2.4%	-1.4%	-8.8%	-21.5%	-11.1%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C									
Forecast	1.3	1.3	1.3	1.3	1.4	1.4	1.3	1.4	1.4
Actual	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.2	1.1
Error = (ACT-FCST)	(0.0)	(0.0)	(0.0)	0.0	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)
Percent Error = (Error/ACT)	-1.7%	-1.3%	-2.4%	0.5%	-6.4%	-9.7%	-4.5%	-15.2%	-22.6%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C									
Forecast	2.2	2.3	2.6	2.5	2.4	2.4	2.0	2.0	1.8
Actual	2.3	2.5	2.4	2.2	2.0	2.0	2.0	1.7	1.1
Error = (ACT-FCST)	0.1	0.2	(0.2)	(0.4)	(0.4)	(0.4)	0.0	(0.2)	(0.7)
Percent Error = (Error/ACT)	4.5%	6.5%	-7.5%	-16.8%	-18.3%	-18.5%	1.6%	-14.0%	-62.8%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C									
Forecast	0.3	0.3	0.3	0.4	0.4	0.4	0.6	0.6	0.5
Actual	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Error = (ACT-FCST)	0.0	0.1	0.1	0.2	0.1	0.1	(0.0)	(0.1)	0.0
Percent Error = (Error/ACT)	9.8%	30.2%	29.9%	30.7%	21.0%	16.7%	-7.8%	-13.1%	5.9%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C									
Forecast	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Actual	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5
Error = (ACT-FCST)	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)
Percent Error = (Error/ACT)	3.1%	3.0%	-1.7%	-5.9%	-3.3%	-6.1%	-2.9%	-15.7%	-13.9%

3.13.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the Vancouver Island 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.

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	4.6	4.6	4.9	5.1	4.9	5.0	4.6	4.5	4.3	4.3
Actual	4.6	4.6	4.7	4.6	4.7	4.7	4.5	4.4	4.5	5.0
Error = (ACT-FCST)	-	-	(0.2)	(0.5)	(0.2)	(0.3)	(0.1)	(0.1)	0.2	0.6
Percent Error = (Error/ACT)	0.0%	0.0%	-4.3%	-10.9%	-4.3%	-6.4%	-2.2%	-2.3%	4.4%	12.9%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	2.9	2.9	3.0	3.1	3.0	3.0	3.3	3.4	3.3	3.3
Actual	2.9	3.1	3.1	3.2	3.1	3.1	3.1	3.0	2.9	3.2
Error = (ACT-FCST)	0.1	0.2	0.1	0.1	0.1	0.1	(0.2)	(0.4)	(0.5)	(0.2)
Percent Error = (Error/ACT)	2.4%	5.2%	3.2%	2.5%	3.2%	1.6%	-5.1%	-14.9%	-16.0%	-4.7%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	2.3	2.4	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.5
Actual	2.4	2.5	2.4	2.4	2.3	2.3	2.3	2.1	1.9	2.4
Error = (ACT-FCST)	0.0	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.1)	(0.3)	(0.5)	(0.1)
Percent Error = (Error/ACT)	1.7%	1.6%	-4.2%	-5.1%	-6.8%	-8.1%	-2.6%	-13.7%	-28.3%	-5.0%

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										0.5
Error = (ACT-FCST)										(0.5)
Percent Error = (Error/ACT)										

Demand, PJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Commercial										
Forecast	5.2	5.3	5.5	5.5	5.5	5.6	5.7	5.8	5.7	5.9
Actual	5.3	5.5	5.5	5.5	5.5	5.4	5.5	5.1	4.8	6.2
Error = (ACT-FCST)	0.1	0.2	-	(0.0)	(0.1)	(0.1)	(0.2)	(0.7)	(1.0)	0.3
Percent Error = (Error/ACT)	2.1%	3.6%	0.0%	-0.7%	-1.1%	-2.6%	-4.0%	-14.4%	-20.8%	4.4%

3.14 *WHISTLER NET CUSTOMERS*

3.14.1 Traditional Rate Schedules

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C									
Forecast	89	88	87	91	84	84	81	81	82
Actual	83	83	82	83	81	83	82	81	86
Error = (ACT-FCST)	(6)	(5)	(5)	(8)	(3)	(1)	1	0	4
Percent Error = (Error/ACT)	-7.2%	-6.0%	-6.1%	-9.6%	-3.7%	-1.2%	1.2%	0.0%	4.7%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C									
Forecast	54	53	48	53	52	52	49	49	50
Actual	48	51	50	51	49	50	50	49	49
Error = (ACT-FCST)	(6)	(2)	2	(2)	(3)	(2)	1	0	(1)
Percent Error = (Error/ACT)	-12.5%	-3.9%	4.0%	-3.9%	-6.1%	-4.0%	2.0%	0.0%	-2.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C									
Forecast	22	22	20	21	22	24	23	23	24
Actual	20	20	20	23	23	24	24	24	24
Error = (ACT-FCST)	(2)	(2)	0	2	1	0	1	1	0
Percent Error = (Error/ACT)	-10.0%	-10.0%	0.0%	8.7%	4.3%	0.0%	4.2%	4.2%	0.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C									
Forecast	181	173	161	166	171	175	187	192	202
Actual	155	159	171	173	177	196	185	193	193
Error = (ACT-FCST)	(26)	(14)	10	7	6	21	(2)	1	(9)
Percent Error = (Error/ACT)	-16.8%	-8.8%	5.8%	4.0%	3.4%	10.7%	-1.1%	0.5%	-4.7%

3.14.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the 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.

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	2,133	2,171	2,124	2,178	2,272	2,321	2,289	2,303	2,372	2,478
Actual	2,064	2,098	2,134	2,250	2,262	2,296	2,271	2,348	2,416	2,508
Error = (ACT-FCST)	(69)	(73)	10	72	(10)	(25)	(18)	45	44	30
Percent Error = (Error/ACT)	-3.3%	-3.5%	0.5%	3.2%	-0.4%	-1.1%	-0.8%	1.9%	1.8%	1.2%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	278	268	254	264	263	267	275	280	291	289
Actual	244	249	260	263	265	286	274	281	285	295
Error = (ACT-FCST)	(34)	(19)	6	(1)	2	19	(1)	1	(6)	6
Percent Error = (Error/ACT)	-13.9%	-7.6%	2.3%	-0.4%	0.8%	6.6%	-0.4%	0.4%	-2.1%	2.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	63	62	57	62	61	62	59	59	61	60
Actual	57	59	58	61	59	61	61	60	60	48
Error = (ACT-FCST)	(6)	(3)	1	(1)	(2)	(1)	2	1	(1)	(12)
Percent Error = (Error/ACT)	-10.5%	-5.1%	1.7%	-1.6%	-3.4%	-1.6%	3.3%	1.7%	-1.7%	-25.0%

Customers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										10
Error = (ACT-FCST)										10
Percent Error = (Error/ACT)										

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

3.15.1 Traditional Rate Schedules

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS 1R									
Forecast		75	30	50	35	36	14	14	52
Actual	19	34	36	116	12	34	51	77	68
Error = (ACT-FCST)	19	(41)	6	66	(23)	(2)	37	63	16
Percent Error = (Error/ACT)	100.0%	-120.6%	16.7%	56.9%	-191.7%	-5.9%	72.5%	81.8%	23.5%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C									
Forecast		2	2	6	1	-	-	-	-
Actual	2	-	(1)	1	(2)	2	(1)	(1)	5
Error = (ACT-FCST)	2	(2)	(3)	(5)	(3)	2	(1)	(1)	5
Percent Error = (Error/ACT)	100.0%		300.0%	-500.0%	150.0%	100.0%	100.0%	100.0%	100.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C									
Forecast	-	1	-	2	-	1	-	-	-
Actual	(3)	3	(1)	1	(2)	1	-	(1)	-
Error = (ACT-FCST)	(3)	2	(1)	(1)	(2)	0	0	(1)	0
Percent Error = (Error/ACT)	100.0%	66.7%	100.0%	-100.0%	100.0%	0.0%		100.0%	

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C									
Forecast	-	-	-	1	-	-	-	-	-
Actual	(1)	-	-	3	-	1	-	-	-
Error = (ACT-FCST)	(1)	0	0	2	0	1	0	0	0
Percent Error = (Error/ACT)	100.0%			66.7%		100.0%			

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C									
Forecast	-	10	3	4	-	2	5	5	9
Actual	2	4	12	2	4	19	1	8	-
Error = (ACT-FCST)	2	(6)	9	(2)	4	17	(4)	3	(9)
Percent Error = (Error/ACT)	100.0%	-150.0%	75.0%	-100.0%	100.0%	89.5%	-400.0%	37.5%	

3.15.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the 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.

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast		75	30	50	35	36	14	14	52	62
Actual	19	34	36	116	12	34	51	77	68	92
Error = (ACT-FCST)	19	(41)	6	66	(23)	(2)	37	63	16	30
Percent Error = (Error/ACT)	100.0%	-120.6%	16.7%	56.9%	-191.7%	-5.9%	72.5%	81.8%	23.5%	32.6%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	-	12	5	10	1	2	5	5	9	4
Actual	(11)	5	11	3	2	21	-	7	5	10
Error = (ACT-FCST)		(7)	6	(7)	1	19	(5)	2	(4)	6
Percent Error = (Error/ACT)		-144.9%	54.5%	-233.3%	50.0%	90.5%		28.6%	-80.0%	60.0%

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast		1		3		1				-
Actual	(3)	2	(1)	3		2	(0)	(1)	(0)	(12)
Error = (ACT-FCST)		1		(0)		1				(12)
Percent Error = (Error/ACT)		52.8%		-2.3%		41.1%				

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										10
Error = (ACT-FCST)										10
Percent Error = (Error/ACT)										

3.16 *WHISTLER USE PER CUSTOMER*

3.16.1 Traditional Rate Schedules

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1R									
Forecast	89.5	89.9	88.2	90.1	92.1	82.3	104.0	106.3	90.6
Actual	85.8	95.7	89.9	82.6	99.5	94.7	89.4	87.3	87.6
Error = (ACT-FCST)	(4)	6	2	(8)	7	12	(15)	(19)	(3)
Percent Error = (Error/ACT)	-4.3%	6.1%	1.9%	-9.1%	7.4%	13.1%	-16.3%	-21.8%	-3.4%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C									
Forecast	1,094.0	1,116.0	1,140.0	1,198.0	1,248.0	1,185.0	1,724.5	1,793.0	1,405.3
Actual	1,152.8	1,284.7	1,316.6	1,185.3	1,595.3	1,484.0	1,237.1	1,317.5	1,353.8
Error = (ACT-FCST)	59	169	177	(13)	347	299	(487)	(476)	(52)
Percent Error = (Error/ACT)	5.1%	13.1%	13.4%	-1.1%	21.8%	20.1%	-39.4%	-36.1%	-3.8%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C									
Forecast	3,137.0	3,235.0	3,253.0	3,283.0	3,098.0	2,454.0	2,500.3	2,361.6	2,367.8
Actual	3,211.7	3,214.1	2,749.7	2,454.4	2,802.7	2,657.7	2,606.2	2,647.5	2,658.4
Error = (ACT-FCST)	75	(21)	(503)	(829)	(295)	204	106	286	291
Percent Error = (Error/ACT)	2.3%	-0.6%	-18.3%	-33.8%	-10.5%	7.7%	4.1%	10.8%	10.9%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C									
Forecast	13,232.0	13,117.0	13,146.0	11,853.0	10,972.0	9,175.0	6,187.4	5,167.1	6,167.7
Actual	13,145.5	11,853.0	11,078.0	9,174.7	8,872.2	8,424.2	8,036.5	8,481.8	8,645.7
Error = (ACT-FCST)	(87)	(1264)	(2068)	(2678)	(2100)	(751)	1849	3315	2478
Percent Error = (Error/ACT)	-0.7%	-10.7%	-18.7%	-29.2%	-23.7%	-8.9%	23.0%	39.1%	28.7%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C									
Forecast	179.0	190.0	206.0	232.0	264.0	251.0	414.9	459.7	281.6
Actual	219.4	265.1	315.6	251.0	338.0	302.3	287.1	294.4	306.9
Error = (ACT-FCST)	40	75	110	19	74	51	(128)	(165)	25
Percent Error = (Error/ACT)	18.4%	28.3%	34.7%	7.6%	21.9%	17.0%	-44.5%	-56.1%	8.3%

3.16.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the 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.

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1										
Forecast	89.5	89.9	88.2	90.1	92.1	82.3	104.0	106.3	90.6	79.7
Actual	85.8	95.7	89.9	82.6	99.5	94.7	89.4	87.3	87.6	91.3
Error = (ACT-FCST)	(4)	6	2	(8)	7	12	(15)	(19)	(3)	12
Percent Error = (Error/ACT)	-4.3%	6.1%	1.9%	-9.1%	7.4%	13.1%	-16.3%	-21.8%	-3.4%	12.7%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2										
Forecast	396.0	414.0	431.0	456.0	464.0	430.0	610.0	637.0	464.0	408.0
Actual	445.0	489.0	502.0	427.0	563.0	506.0	429.0	465.0	471.0	660.0
Error = (ACT-FCST)	49	75	71	(29)	99	76	(181)	(172)	7	252
Percent Error = (Error/ACT)	11.0%	15.3%	14.1%	-6.8%	17.6%	15.0%	-42.2%	-37.0%	1.5%	38.2%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3										
Forecast	5,165.0	5,286.0	5,286.0	5,092.0	4,894.0	4,114.0	3,876.0	3,630.0	3,595.0	3,822.0
Actual	5,288.0	5,107.0	4,641.0	4,037.0	4,512.0	4,271.0	3,822.0	4,213.0	4,285.0	5,618.0
Error = (ACT-FCST)	123	(179)	(645)	(1,055)	(382)	157	(54)	583	690	1,796
Percent Error = (Error/ACT)	2.3%	-3.5%	-13.9%	-26.1%	-8.5%	3.7%	-1.4%	13.8%	16.1%	32.0%

UPC, GJs	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23										
Forecast										
Actual										4,328.0
Error = (ACT-FCST)										
Percent Error = (Error/ACT)										

3.17 *WHISTLER DEMAND*

3.17.1 Traditional Rate Schedules

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS 1R										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Actual	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)
Percent Error = (Error/ACT)	2.4%	-6.9%	3.5%	2.0%	-7.5%	7.5%	12.0%	-14.2%	-21.5%	-1.4%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C										
Forecast	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Actual	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Error = (ACT-FCST)	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)
Percent Error = (Error/ACT)	8.2%	1.7%	9.4%	10.1%	-6.6%	20.6%	17.7%	-37.0%	-34.8%	-4.2%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Actual	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0
Percent Error = (Error/ACT)	8.9%	-7.3%	-6.8%	-13.3%	-38.2%	-14.3%	3.8%	6.0%	12.0%	9.1%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C										
Forecast	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1
Actual	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Error = (ACT-FCST)	0.0	(0.0)	(0.1)	(0.0)	(0.1)	(0.0)	(0.0)	0.1	0.1	0.1
Percent Error = (Error/ACT)	6.2%	-3.3%	-21.7%	-18.7%	-28.9%	-14.8%	-11.3%	26.2%	41.6%	28.7%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C										
Forecast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Actual	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1
Error = (ACT-FCST)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0
Percent Error = (Error/ACT)	18.6%	7.2%	23.6%	36.4%	12.8%	23.5%	22.1%	-40.5%	-55.0%	8.2%

3.17.2 Amalgamated Rate Schedules

In order to provide historical amalgamated data, FEI mapped the 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.

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 1											
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
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)	2.4%	-6.9%	3.5%	2.0%	-7.5%	7.5%	12.0%	-14.2%	-21.5%	-1.4%	0.0%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 2											
Forecast	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1
Actual	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	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	0.1
Percent Error = (Error/ACT)	9.1%	0.0%	8.3%	15.4%	-9.1%	20.0%	21.4%	-33.3%	-30.8%	0.0%	36.8%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 3											
Forecast	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Actual	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.2	0.3	0.3	0.3
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.1
Percent Error = (Error/ACT)	6.3%	-6.7%	-10.3%	-11.1%	-29.2%	-11.1%	3.8%	0.0%	15.4%	15.4%	17.9%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate Schedule 23											
Forecast											
Actual											0.03
Error = (ACT-FCST)											
Percent Error = (Error/ACT)											

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Commercial											
Forecast	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Actual	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	(0.0)	(0.1)	0.0	0.0	(0.0)	0.0	0.0	0.2
Percent Error = (Error/ACT)	7.0%	-4.9%	-4.9%	-2.5%	-22.9%	0.0%	10.0%	-11.4%	0.0%	10.3%	30.0%

Appendix A2-1

HISTORICAL FORECAST AND CONSOLIDATED TABLES

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix A3

Demand Forecast Methodology

Table of Contents

List of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides a detailed description of its demand forecast methodology.

The following table shows the high level methodology 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 2017 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 a range of 2 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.

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 multiplying 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 square 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 are tested to see which provides the best fit for each rate class by 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 demand forecast is the product of the number of customers and the use rate. The forecast number of customers is determined by using the actual customer additions[1] from the most recent year, and applying a forecast growth rate for customer additions.

This section describes the residential customer additions forecast methodology, beginning with a general description and followed by a step-by-step discussion of the forecast.

FEI's forecast of annual net customer additions is based on the correlation between FEI's net customer additions and the Conference Board of Canada (CBOC) forecast of housing starts. FEI begins with the most recent year of recorded FEI actual customer additions by rate schedule, region and housing type. FEI then calculates the annual customer growth rate from the CBOC forecast for single-family and mufti-family dwellings. FEI's forecast net customer additions are then calculated by applying the growth rates to the most recent actual customer counts.

Forecasting is completed at the annual and regional level. Based on historical seasonality, the annual forecast is distributed to create the monthly forecast that is then entered into FEI's Forecast Information System (FIS). The regional annual forecasts are then summed to create the amalgamated forecast.

FEI uses the most recent Provincial Medium Term Housing Starts Forecast from the (CBOC) to develop growth rates by housing type.

The CBOC forecast is also used because it provides a forecast for both single family dwellings (SFD) and multi-family dwellings (MFD).

With the known most recent year of actual additions by housing type and the forecast growth rates by housing type, the net additions forecast can be calculated by multiplying the actual SFD and MFD additions by the applicable growth rate.

Customers are not added at the same rate throughout the year. As a result, the regional annual forecasts calculated above are seasonalized to calculate forecast monthly customer additions.

The above process is repeated for all regions and the results are aggregated.

[1] Customer additions or "net" customer additions is the year-over-year change in the total number of customers.

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated using a three-year average of prior actuals additions at the region and rate class level.

The starting point for the customer additions forecast is the actual month-end customer counts as recorded in FEI's billing system for each region and commercial rate schedule.

The month-end customer totals are used to determine the monthly net additions for three years by calculating the difference between consecutive months.

Once the regional and monthly additions have been calculated, three-year average seasonality factors can be calculated.

The actual customer additions are used to develop three-year average customer additions by sub-region.

The three-year average is used as the annual forecast commercial customer additions for both the seed and forecast years.

The three-year average annual forecast is then converted into a monthly forecast using seasonality factors.

The month end forecast as entered into FIS starts with the December actual customer count and adds the monthly additions.

5. RESIDENTIAL USE RATE

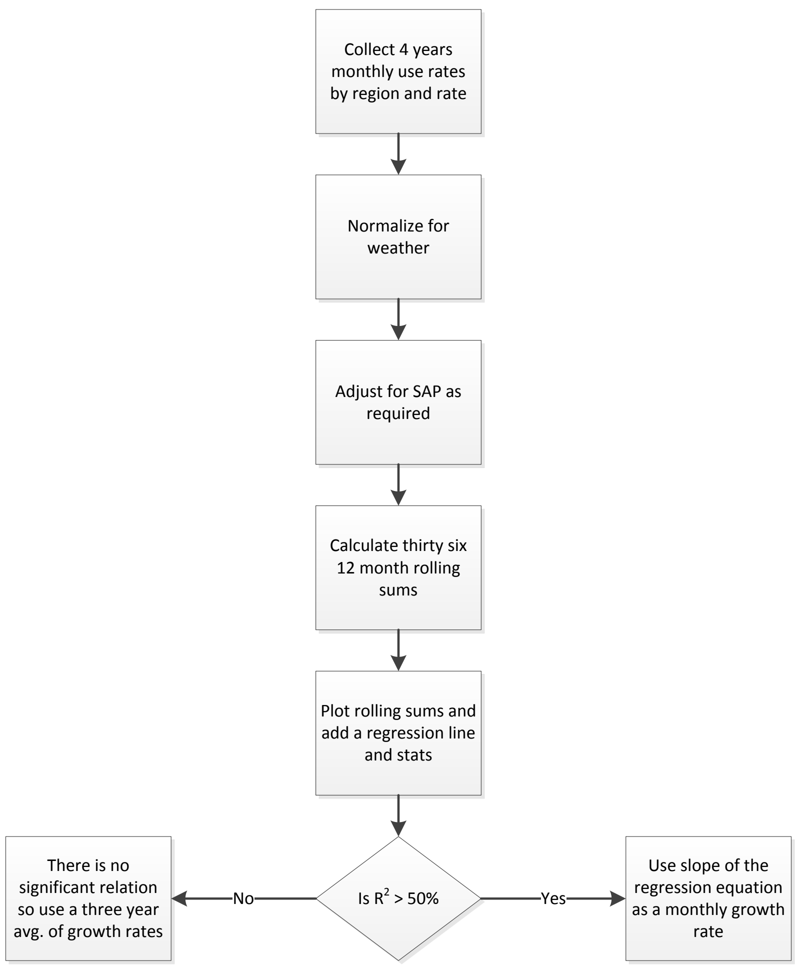
The Residential Demand Forecast is the product of the number of residential customers and the residential use rate. This section describes the method for forecasting the residential use rate.

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: Rate Schedule 1 Use Rate Flow Chart



5.2 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. Monthly regional use rates cannot simply be summed or averaged to provide the correct amalgamated use rate. The amalgamated use rate must be 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 schedule for all regions.

6. COMMERCIAL USE RATE

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

6.1 MONTHLY WEATHER-NORMALIZED ACTUAL UPCS

FEI's commercial use rate forecast is developed in the same manner as the residential use rate forecast discussed above. The method is based on four years of monthly use rates by region and rate class. The monthly UPC values are weather-normalized using the process described in Section 2 above. As with the residential forecast discussed 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.

Once the annual UPC forecasts for each region are complete they are seasonalized and loaded into FIS to develop the load forecast by region .

6.2 AMALGAMATION OF UPCS

Once the use rates are seasonalized and developed for each region and each rate schedule (rates 1, 2, 3 and 23) they are entered into FIS. As discussed in section 5.2, 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.

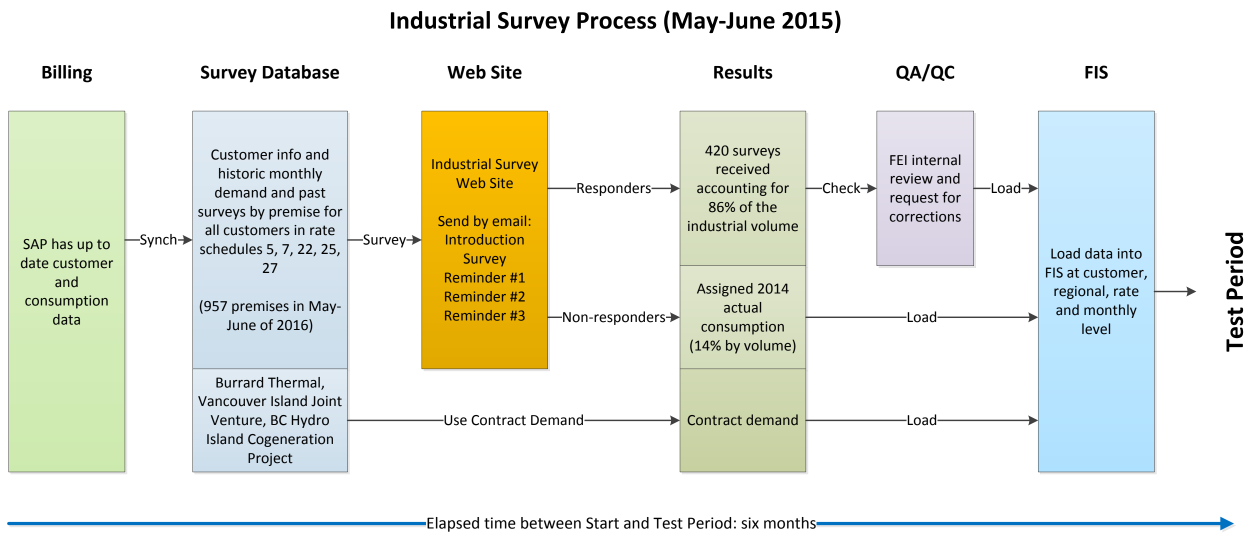
7. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the simple products of the monthly customer forecast and the matching 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.

8. INDUSTRIAL DEMAND FORECAST

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

Figure A3-3: 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.

8.1 CREATE THE SURVEY

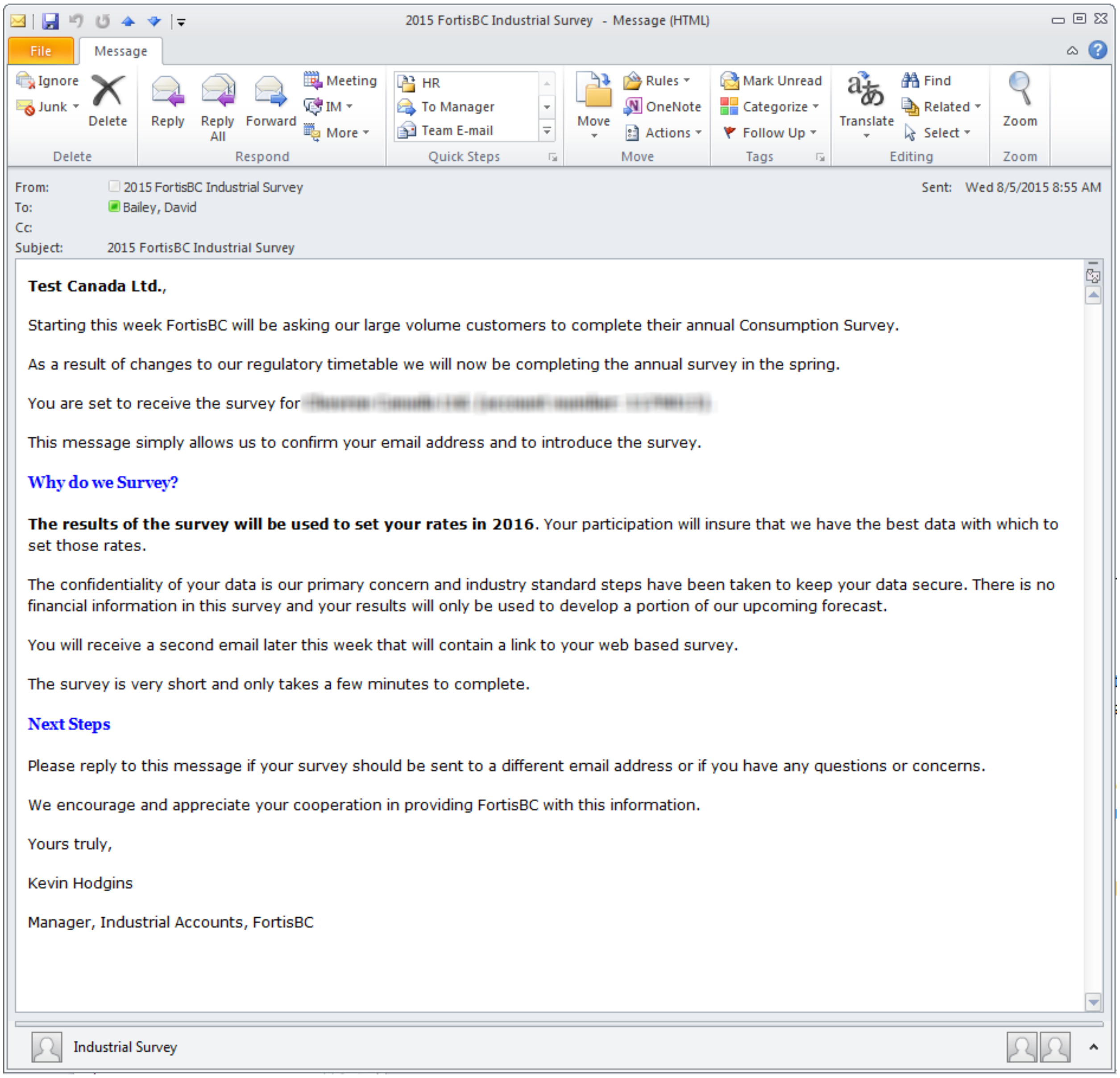
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

8.2 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 above form letters and manages the send out. The following is an example of the introductory email.

Figure A3-4: Survey Introductory Email Example



2015 FortisBC Industrial Survey - Message (HTML)

From: 2015 FortisBC Industrial Survey
To: Bailey, David
Cc:
Subject: 2015 FortisBC Industrial Survey
Sent: Wed 8/5/2015 8:55 AM

Test Canada Ltd.,

Starting this week FortisBC will be asking our large volume customers to complete their annual Consumption Survey.

As a result of changes to our regulatory timetable we will now be completing the annual survey in the spring.

You are set to receive the survey for [redacted]

This message simply allows us to confirm your email address and to introduce the survey.

Why do we Survey?

The results of the survey will be used to set your rates in 2016. Your participation will insure that we have the best data with which to set those rates.

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 later this week that will contain a 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,

Kevin Hodgins

Manager, Industrial Accounts, FortisBC

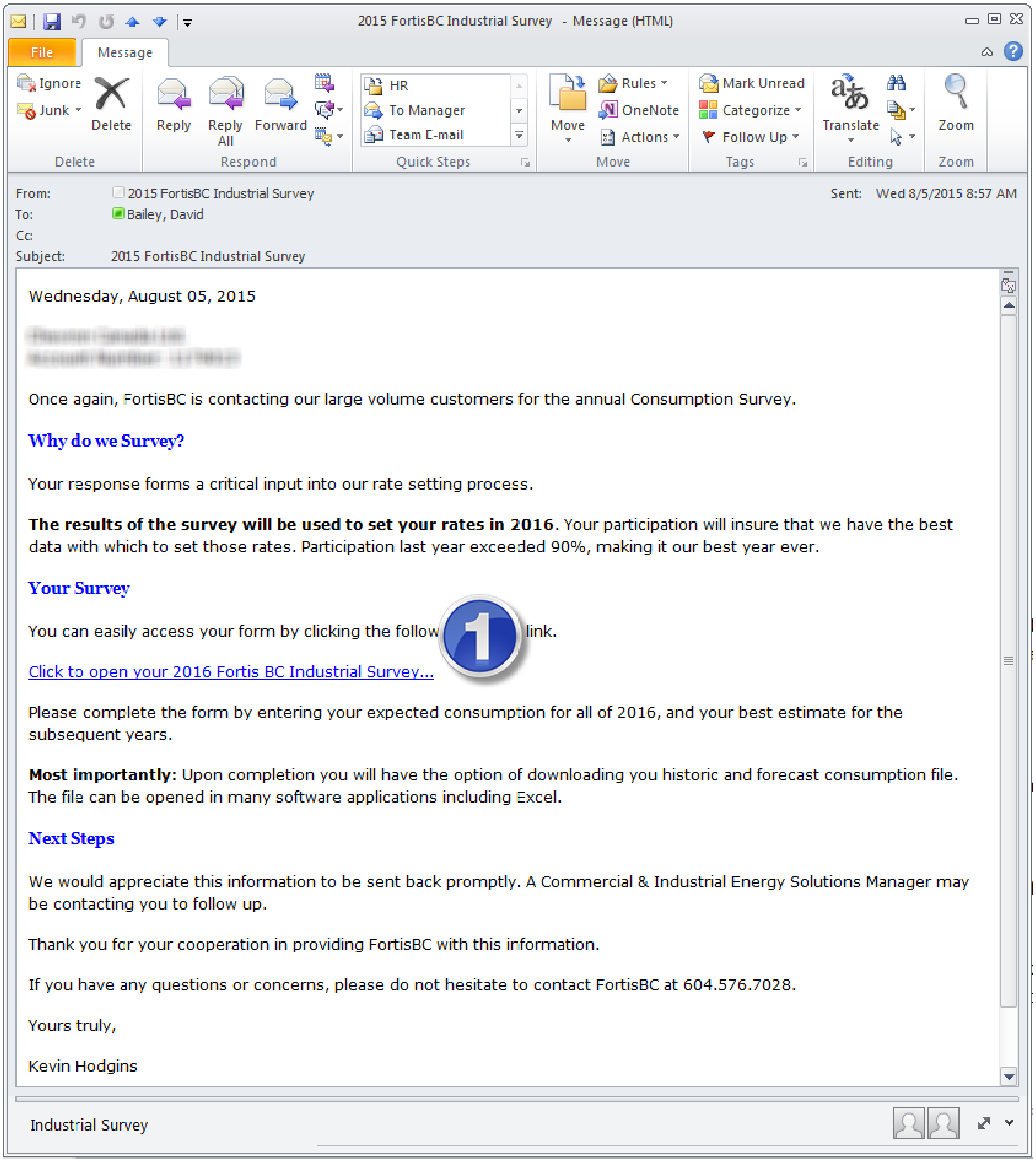
Industrial Survey

Replies to these emails are used to update the contact and other information in the survey web site.

8.3 *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.

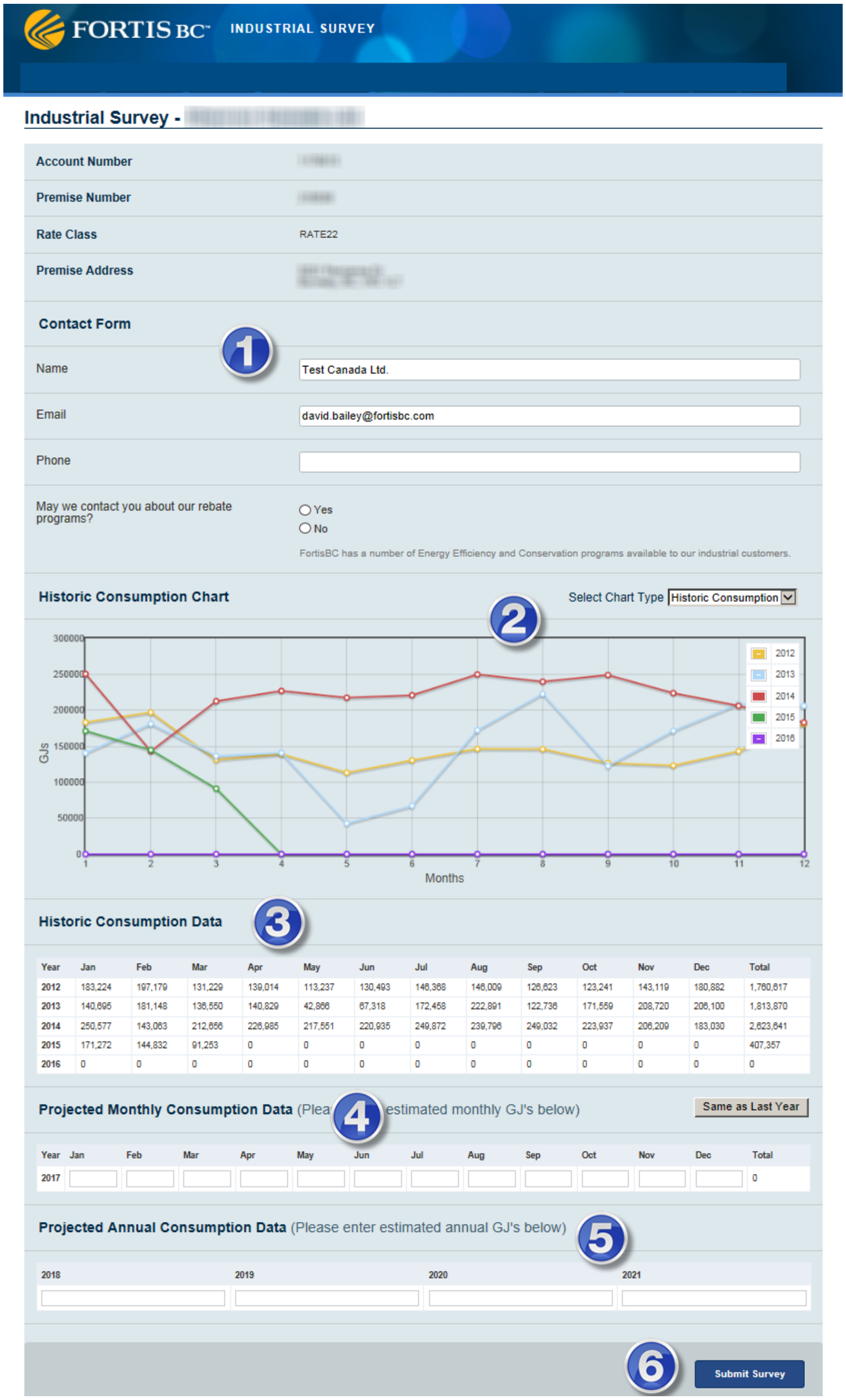
Figure A3-5: Survey Email Example



8.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

Figure A3-6: Survey (Web) Form Example



FORTIS BC INDUSTRIAL SURVEY

Industrial Survey -

Account Number	
Premise Number	
Rate Class	RATE22
Premise Address	

Contact Form 1

Name: Test Canada Ltd.

Email: david.bailey@fortisbc.com

Phone:

May we contact you about our rebate programs? Yes / No

FortisBC has a number of Energy Efficiency and Conservation programs available to our industrial customers.

Historic Consumption Chart 2 Select Chart Type: Historic Consumption

Historic Consumption Data 3

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	183,224	197,179	131,229	139,014	113,237	130,493	146,368	146,009	126,623	123,241	143,119	180,882	1,760,617
2013	140,695	181,148	136,550	140,829	42,866	67,318	172,458	222,891	122,736	171,559	208,720	206,100	1,813,870
2014	250,577	143,063	212,656	226,985	217,551	220,935	249,872	239,796	249,032	223,937	206,209	183,030	2,623,641
2015	171,272	144,832	91,253	0	0	0	0	0	0	0	0	0	407,357
2016	0	0	0	0	0	0	0	0	0	0	0	0	0

Projected Monthly Consumption Data (Plea 4 estimated monthly GJ's below) Same as Last Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017													0

Projected Annual Consumption Data (Please enter estimated annual GJ's below) 5

2018	2019	2020	2021

6 Submit Survey

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 customers 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 show 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.

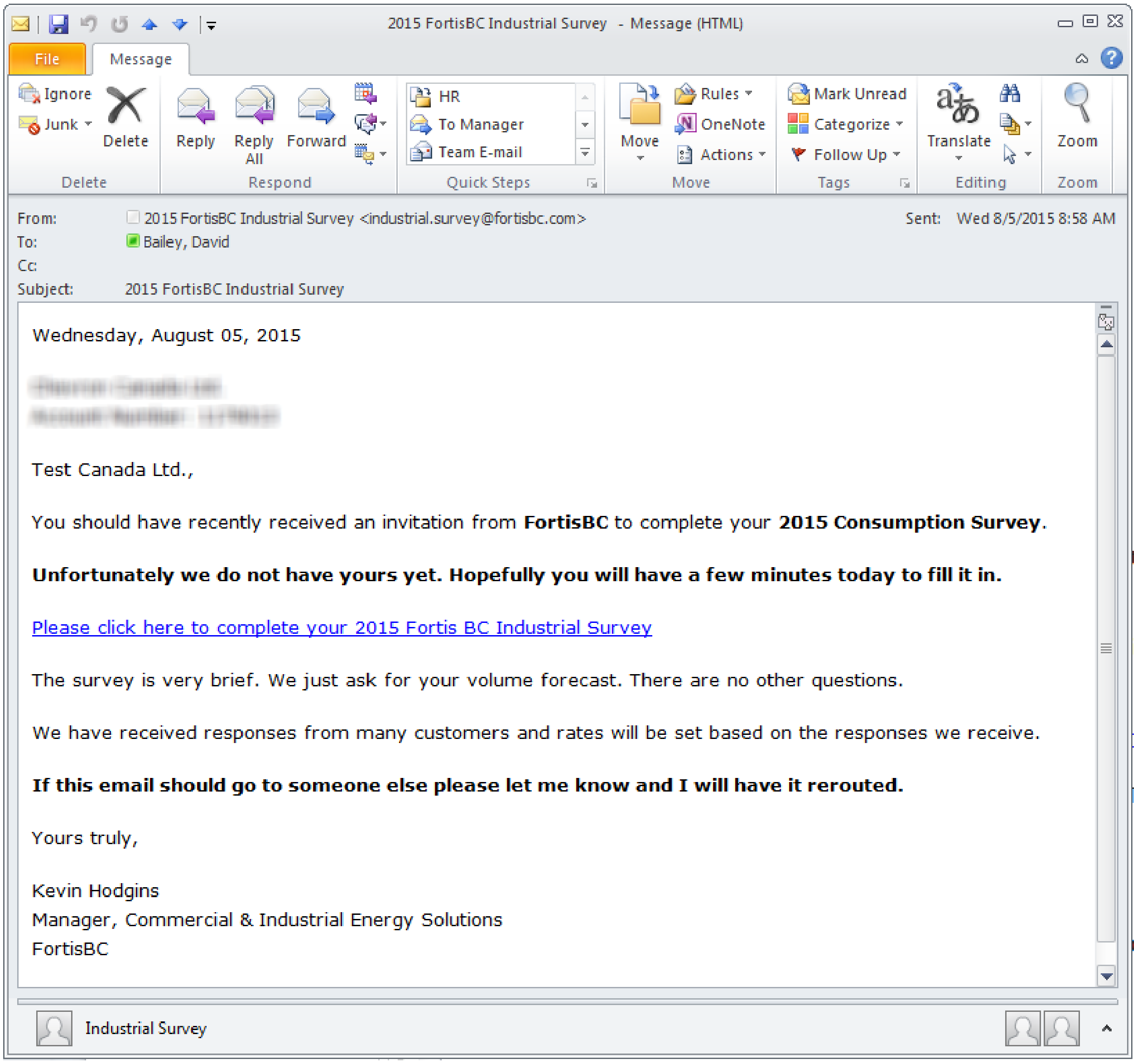
5) Annual forecasts are requested for the remaining 4 years of the survey.

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.

8.5 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 A3-7: Example of Survey Reminder Email


2015 FortisBC Industrial Survey - Message (HTML)

From: 2015 FortisBC Industrial Survey <industrial.survey@fortisbc.com>
Sent: Wed 8/5/2015 8:58 AM
To: Bailey, David
Cc:
Subject: 2015 FortisBC Industrial Survey

Wednesday, August 05, 2015

[redacted]

Test Canada Ltd.,

You should have recently received an invitation from **FortisBC** to complete your **2015 Consumption Survey**.

Unfortunately we do not have yours yet. Hopefully you will have a few minutes today to fill it in.

Please click here to complete your 2015 Fortis BC Industrial Survey

The survey is very brief. We just ask for your volume forecast. There are no other questions.

We have received responses from many customers and rates will be set based on the responses we receive.

If this email should go to someone else please let me know and I will have it rerouted.

Yours truly,

Kevin Hodgins
Manager, Commercial & Industrial Energy Solutions
FortisBC

Industrial Survey

8.6 *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 A3-8: Example of Survey Results Dashboard

8.7 *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 as required.

8.8 *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 years consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

9. SUMMARY OF DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month, region and rate class to prepare the overall forecast of demand.

Appendix A4

Forecasting Directives

Table of Contents

List of Appendices

1. INTRODUCTION

In this Report, FEI presents the results of its research in compliance with the Commission's three directives applicable to FEI's demand forecasting methodology (the Forecasting Directives) in Order G-86-15 and accompanying Decision (the Decision) related to the FEI Annual Review for 2015 Rates Application.[1] Table A4-1 provides a description of the Forecasting Directives.

Table A4-1: Order G-86-15 Forecast Methodology Directives[2]

No.	Directive
3	The Panel directs FEI to review alternative methodologies and develop one that overcomes the identified shortcomings and more accurately predicts actual average UPC for the next annual review.
5	The Panel directs FEI to include commercial customers as part of its review of alternative methodologies for forecasting UPC for the next annual review.
8	The Panel directs FEI to consider alternative methods for forecasting commercial customer additions which are appropriately sensitive to the business cycle. FEI is to provide an analysis of these alternatives in its next annual review application.

In compliance with the Forecasting Directives, FEI has identified and tested alternate methods to forecast residential and commercial use rates and commercial customer additions. Based on the results of the testing, FEI recommends the continued use of its existing demand forecast method and that further testing be completed on the most promising alternate method over the remaining term of the performance based ratemaking (PBR) plan. The results of the further testing will then inform a final recommendation on the preferred forecasting method at the end of the PBR term.

The key findings of this Report are as follows:

1. The average residential demand forecast error from natural gas utilities captured in three separate surveys is 4.1 percent. Using its existing method, FEI's average absolute residential forecast error over the previous ten years was 2.1 percent and the absolute error in 2015 was 1.3 percent.

[1] On July 10, 2015, FEI filed a letter with the Commission requesting approval to extend the filing deadline to April 30, 2016 due to the scope of the work identified by FEI to comply with the Commission's directives. In Letter L-30-15, the Commission approved a modification of FEI's request, directing that FEI file its final report on alternative load forecasting methodologies, including FEI's proposed course of action, as part of the annual review of 2017 delivery rates application in September 2016. In addition, the Commission requested that FEI file a progress report with the Commission by April 30, 2016, which was filed on April 27, 2016.

[2] In addition, in Appendix A to Order G-193-15 on page 20, the Commission stated "With regards to the Rate Schedule 23 demand forecast, the Panel is satisfied that the forecasting methodology is reasonable for the purposes of forecasting 2016 demand and reiterates our expectation that this forecasting methodology will be reviewed as part of FEI's overall forecasting methodology review process as directed in the FEI Annual Review of 2015 Delivery Rates Decision and letter L-30-15."

2. The average commercial demand forecast error reported by natural gas utilities responding to the three surveys was also 4.1 percent. FEI's existing method also performed better than this level in nine of the prior ten years, with only 2009 exceeding this average. FEI's average absolute commercial demand forecast error over the past ten years was 2.0 percent and the absolute error in 2015 was 0.3 percent.
3. FEI identified a number of alternate forecasting methods to test in an effort to improve on the performance of FEI's existing method.
4. In detailed testing, the method called Holt's Exponential Smoothing (ETS) was the best performing alternate method tested. In some years ETS performed better than the existing method and in some years it performed worse.
5. ETS has been implemented by Microsoft in its most recent Excel release (2016), making it efficient to implement as a replacement method.
6. While the ETS method is promising, FEI cannot conclusively determine that it is superior to its existing method without further years of comparative results.
7. FEI will run parallel forecasts for the remainder of the PBR term with the intention of making a final decision regarding the preferred forecasting method when more years of comparative results are available. The remaining term of the PBR provides a good opportunity to continue testing ETS as any variances in the demand forecast are captured in the Flow-through deferral account.

The remainder of this Report is organized as follows:

Section 2	The Forecasting Directives This section reviews the directives as issued by the Commission.
Section 3	Demand Forecast Definitions This section reviews some standard definitions and derivations used throughout the Report to measure the effectiveness of current and alternate methods.
Section 4	Performance Review In the Annual Review for 2016 Rates, FEI cited[3] a performance survey conducted by ITRON Inc. (ITRON). The survey was informative but lacked detail. For the purpose of this Report and to augment the ITRON survey, FEI contracted a consultant to perform a forecasting performance survey. The intent of the survey was to gather performance information from a sample of ten gas utilities. Section 4 reviews the key findings from the survey as well as the results from the latest ITRON survey.
Section 5	Alternative Methods to Forecasting Based on the literature reviewed, FEI selected several alternate methods to evaluate. Section 5 discusses the pros and cons of each alternate method.

[3] Annual Review for 2016 Rates, Appendix A2 pages 5-7

Section 6	Alternative Method Testing In Section 6 the test procedure is described and the results from the alternate method testing are presented.
Section 7	Recommendation In Section 7 FEI presents the recommendations from this Report.

2. THE FORECASTING DIRECTIVES

As summarized in Section 1 above, the Forecasting Directives were:

- The Panel directs FEI to review alternative methodologies and develop one that overcomes the identified shortcomings and more accurately predicts actual average UPC for the next annual review.
- The Panel directs FEI to include commercial customers as part of its review of alternative methodologies for forecasting UPC for the next annual review.
- The Panel directs FEI to consider alternative methods for forecasting commercial customer additions which are appropriately sensitive to the business cycle. FEI is to provide an analysis of these alternatives in its next annual review application.

The Commissions' concerns that led to the Forecasting Directives as recorded in the Decision are reproduced below.

Regarding the residential use per customer (UPC) forecast, the Decision states:[4]

> The Panel has concerns with both the efficacy of FEI's 2015 average residential UPC forecast as well as the methodology it has applied to determine this forecast.
>
> As outlined in Table 2, FEI has under-forecasted average residential UPC on a consolidated basis four out of five times from 2009 through 2014. The residential average UPC forecast presented in the Application (and included as Figure 1 in this Decision) shows a decline of 1.6 GJs on a consolidated basis from 2013 to 2014 and a further decline of 1.6 GJs from 2014 to 2015. The forecast of consolidated UPC presented in response to BCUC IR 1.5.1.1 (see Table 2) differs significantly from the Application. Based on BCUC IR 1.5.1.1, the forecast average UPC for 2014 is 85.4 GJs which represents an increase of 1 GJ over 2013. Further, the 2015 forecast average UPC has changed to 81.1 GJs, which represents a decline of 4.3 GJs from the previous year based on the data in Table 2. This is a significant departure from the forecast shown in the Application with no explanation for this difference provided. Given FEI's historical forecast accuracy and the difference in forecasts between the Application and the response to BCUC IR 1.5.1.1, the Panel is not persuaded that the forecast residential average UPC on a consolidated basis can be relied upon. **Therefore, the Panel rejects FEI's forecast residential average UPC of 81.5 GJ for 2015.** The Panel considers that repeating the 2014 forecast provided in the Application of 83.1 GJs is more appropriate for 2015 as it reflects a more reasonable forecast given the variation in 2014 and 2015 forecast information between BCUC IR 1.5.1.1 and the Application. **Therefore, the Panel directs FEI to adjust its 2015 residential UPC forecast to 83.1 GJ as part of its compliance filing.**

[4] Decision, Page 8

> The Panel is also concerned with the forecast methodology itself. CEC and BCOAPO submit that the number of years relied upon by FEI in preparing its forecasts are too few and recommend that the forecast period be lengthened. FEI has argued that it is most important that data is not outdated and that limiting the timespan will more accurately reflect current trends. The Panel has additional concerns. A reliance on averages whether they be over 3, 5 or 10 year periods is ineffective as a means of determining future needs when either an upward or downward trend exists. An average is just that, it will reflect a number which is too high when UPC has been declining and too low when UPC is increasing. However, relying on regression analysis with 3 years history is equally fraught with difficulties as a much longer period is generally required to provide reliable results. Moreover, FEI's practice of breaking a 3-year forecast into monthly totals may reduce accuracy as the smoothing out of seasonal demand may introduce other errors into the regression equation. Further, a reliance on more than one method and combining them to arrive at a forecast is questionable and is a potential source of forecasting error. Given FEI's forecasting history and the noted problems with the present methodology, the Panel considers a review of forecasting alternatives is warranted. **Accordingly, the Panel directs FEI to review alternative methodologies and develop one that overcomes the identified shortcomings and more accurately predicts actual average UPC for the next annual review.**

With respect to the commercial UPC forecast, the Decision states:[5]

> **The Panel approves FEI's commercial UPC forecasts as filed.** The Panel notes that commercial UPC forecasts for 2015 are directionally in line with past performance and in spite of identified problems related to relying upon averages when a trend exists, the averaging methodology has produced reasonable results in the past. In addition, any variances which do occur are managed through the RSAM which mitigates ratepayer risk. However, given the identified problems, and consistent with the Panel determination in Section 2.1.2.1 above, **the Panel directs FEI to include commercial customers as part of its review of alternative methodologies for forecasting UPC for the next annual review.**

Regarding the forecast of residential and commercial net customer additions, the Decision states:[6]

> The Panel approves FEI's 2015 forecast for residential net customer additions and accepts the use of CBOC housing starts as a proxy for these additions. Given that FEI capture rates are significantly different for single family versus multi-family dwellings, the disaggregated forecast provided by CBOC is a valuable tool for information which may not otherwise be readily available. Moreover, the impact on rates is small given the relatively minor impact a small variance on net customer additions has on total customers in a given year.

[5] Decision, Page 9
[6] Decision, Page 10

> The Panel also approves FEI's 2015 forecast for commercial net customer additions, as the 2015 forecast is in keeping with the recent actual customer additions and none of the interveners have taken issue with this forecast. However, the Panel notes that overall the historical accuracy of commercial customer additions forecasts has been poor. Accordingly, the Panel directs FEI to consider alternative methods for forecasting commercial customer additions which are appropriately sensitive to the business cycle. FEI is to provide an analysis of these alternatives in its next annual review application.

In the table below, FEI responds to some of the specific statements in the Directives to ensure that there is a common understanding of the issues that were raised and to assist with an understanding of the remainder of this Report.

Table A4-2: Issues and Commentary Related to the Decision

Statement in the Decision	FEI
Re Residential UPC: "FEI has under-forecasted average residential UPC on a consolidated basis four out of five times from 2009 through 2014." (Page 8).	Section 3.4 of Appendix A2 shows that FEI under forecast three times and over forecast three times in the six-year period from 2009 to 2014. The IR response that was the source of the statement in the Decision was prepared from less detailed data, which incorrectly showed FEI as under forecasting four out of five times from 2009 to 2014.
Re Residential UPC: "A reliance on averages whether they be over 3, 5 or 10 year periods is ineffective as a means of determining future needs when either an upward or downward trend exists." (Page 8). "An average is just that, it will reflect a number which is too high when UPC has been declining and too low when UPC is increasing." (Page 8).	FEI relies on averages only when the use rate is not increasing or decreasing following a statistically significant trend. If the use rate has been declining or increasing consistently, then a statistically significant trend will exist. If such a trend exists then a method is used that incorporates that trend. If a trend is not present, then a trending method cannot be used, and an average method is used instead. As discussed on page 141 of the textbook *Forecasting Methods and Applications*,[7] it is appropriate to forecast data that contain no seasonal effect and no trend effect with a simple average.
Residential UPC: "However, relying on regression analysis with 3 years history is equally fraught with difficulties as a much longer period is generally required to provide reliable results." (Page 8).	The data used in forecasting is the aggregation of many data points. Three years of data represents 36 monthly billing periods over hundreds of thousands of customers. When FEI uses the prior three years' monthly data to perform a regression, it also incorporates a moving average to eliminate seasonality. Based on the data in section 3.4 of Appendix A2, the 10 year residential MAPE for the aggregate UPC forecast is 1.7%.

[7] Makridakis, S. G., Wheelwright, S. C., & Hyndman, R. J., *Forecasting: Methods and Applications* (New York: John Wiley & Sons, 1998), section 3-2.

Statement in the Decision	FEI
Residential UPC: "Moreover, FEI's practice of breaking a 3-year forecast into monthly totals may reduce accuracy as the smoothing out of seasonal demand may introduce other errors into the regression equation." (Page 8).	The 12 month moving average removes the seasonality so that the underlying trend remains. The use of 12 month moving average smoothers is discussed in the textbook *Forecasting Methods and Applications*,[8] where the authors state "Moving averages are a fundamental building block in all decomposition methods"[9] and "The centered 4 MA [4-month moving average] and centered 12 MA [12-month moving average] are frequently used for estimating a trend-cycle in quarterly and monthly data."[10] FEI is not aware of any errors that could be introduced by smoothing out seasonal demand.
Residential UPC: "Further, a reliance on more than one method and combining them to arrive at a forecast is questionable." (Page 8).	FEI approach is methodologically sound. FEI prepares forecasts at the regional level. Each region is tested for the presence of a trend independent of other regions. If a trend is shown to exist FEI uses a method that incorporates that trend. If a trend is absent then a trending method cannot be used, and a moving average is used. The regional demand results are then summed to produce the FEI forecast.
Commercial UPC: "The Panel notes that commercial UPC forecasts for 2015 are directionally in line with past performance and in spite of identified problems related to relying upon averages when a trend exists, the averaging methodology has produced reasonable results in the past." (Page 9).	As stated above, FEI does not rely on an average when a trend exists. FEI tests for a trend. If a trend exists, then it is used. If a trend does not exist, then FEI uses an average.
Commercial Customer Additions: "However, the Panel notes that overall the historical accuracy of commercial customer additions forecasts has been poor." (Page 10).	As discussed in this Report, the performance of the aggregate demand forecast is the most relevant indicator of forecast performance. If the forecast is broken down into smaller components (e.g. by region and rate schedule), then higher individual percentage errors can materialize. However, the aggregate demand forecast is the basis for FEI's revenue forecast and is what has an impact on rates. The performance of FEI's existing method has consistently exceeded industry averages.

8 Ibid
9 Ibid, p. 89.
10 Ibid., p. 7.

3. DEMAND FORECAST DEFINITIONS, PRINCIPLES AND STATISTICS

3.1 DEFINITIONS

There are several definitions used throughout the Report as follows:

Region: There are three regions in the FEI service territory: Mainland, Vancouver Island and Whistler.

Sub-region: The Mainland region is further divided into three sub-regions (Lower Mainland, Inland and Columbia). The Vancouver Island and Whistler regions do not contain any other sub-regions.

Rate Schedule: A rate schedule is a schedule attached to and forming part of a Tariff, which sets outs rates that can by charged by FEI to its customers, as approved by the Commission.

Rate Group: A rate group is a collection of similar rate schedules. For example, the commercial rate group includes rate schedules 2, 3 and 23. The residential rate group contains a single rate schedule (rate schedule 1). Forecast methods are applied consistently to all rate schedules in a rate group.

The rate schedules and rate groups discussed in this Report are summarized as follows:

Table A4-3: Rate Schedules and Rate Groups

Rate Schedule	Rate Group	Notes
1	Residential	Single Family Dwelling (SFD) and Multi Family Dwelling (MFD) (separately metered), and single metered apartment blocks (with four or less apartments)
2	Commercial	Normalized Annual consumption - Less than 2,000 GJ
3	Commercial	Normalized Annual consumption - More than 2,000 GJ
23	Commercial	Normalized Annual consumption – More than 2,000 GJ, Shipper (Customer) must enter into a Transportation Agreement with FEI and appoint a Shipper Agent (Gas Marketer)

3.2 FORECAST PRINCIPLES

The focus of the Forecasting Directives is on the use rate and customer additions forecasts. These forecasts are only components of the demand forecast which in aggregate is used to calculate the revenue forecast. To develop the revenue forecast, the demand forecast is used as follows:

$$Revenue\ Forecast = Demand\ Forecast\ \times Tariffs$$

The overall demand forecast is therefore what determines the revenue forecast and customer rates. For this reason, FEI believes that the Commission's objective in directing FEI to explore alternate forecasting methods was to minimize the error in the demand forecast, thus also minimizing the error in the revenue forecast.

For residential and commercial rate schedules, the demand forecast is always the product of a use rate forecast and a customer forecast. This Report examines alternate methods for both use rate and customer forecasts. This report examines alternate forecast methods for both use rates and customers. To enable the results of the different methods to be consistently compared with one another, FEI utilizes demand forecast errors to measure forecast accuracy.

3.3 *A REVIEW OF STATISTICS USED IN THIS REPORT*

3.3.1.1 Percent Error

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.

3.3.1.2 Absolute Percent Error (APE)

APE is the absolute percent error for one measurement and is defined as:

$$APE = |PE_t|$$

3.3.1.3 Mean Absolute Percent Error (MAPE)

MAPE is the mean absolute percent error across a number ("n") of time periods and is defined as:

$$MAPE = \frac{1}{n}\sum_{t=1}^{n}|PE_t|$$

MAPE eliminates the cancellation effect of positive and negative errors over time. The result of the MAPE calculation is a simple percentage making it easy to compare different forecasts and methods regardless of the underlying units (e.g. customers or demand). MAPE will be used in this Report to evaluate forecast performance.

4. PERFORMANCE REVIEW

4.1 OVERVIEW OF METHOD

FEI cited a 2014 demand performance survey conducted by ITRON[11] in the Annual Review for 2016 Rates. Based on the 2014 ITRON survey, FEI concluded that its current forecast methods performed better than the average of the utilities that participated in the survey.

To augment the ITRON results previously reported, FEI retained Boreas Consulting[12] (Boreas) to survey 10 natural gas utilities in early 2016 to collect additional data on commercial and residential demand forecast performance. Boreas focused on Canadian natural gas utilities and added some US utilities where the data was available. Boreas's survey covered the seven years from 2009 to 2015. The source of the information was generally online filings, but utilities were contacted by phone as required. As expected, different utilities have different levels of reporting, but most reported their forecast and actual demand.

Additionally, an updated 2015 ITRON survey was reviewed.

With two ITRON surveys and the Boreas survey (included in Appendix B), FEI believes it has a reasonable estimation of MAPE values for both residential and commercial demand forecasts.

4.2 RESULTS OF BOREAS SURVEY

The Boreas results for residential demand are shown in Tables A4-4 and A4-5 below. Natural gas utility names have been removed and replaced with letters. As can be seen from the results shown, different utilities had data available for different years.

Outlier testing[13] was performed on the survey results and Utility H was found to be an outlier in 2010 for residential and in both 2010 and 2012 for commercial. FEI removed the survey results that were determined to be outliers from both the residential and commercial demand analysis. In all cases the scores that were removed were higher than the rest of the group, resulting in a lower average for the group.

FEI then calculated the MAPE for each utility, using the data each one had available. This average is shown in the last row of the tables. For the residential rate group the average percent error is 5.6 percent. For the commercial rate group the average is 4.9 percent.

[11] See Appendix A for the results of the 2014 and 2015 ITRON Surveys.
[12] See Appendix B for the full Boreas report.
[13] Outlier testing done using Grubb's Test. See http://www.real-statistics.com/students-t-distribution/identifying-outliers-using-t-distribution/grubbs-test/

Table A4-4: Residential Demand Forecasting Accuracy for Sample Group

Residential Demand	2009	2010	2011	2012	2013	2014	2015	MAPE
B	-6.8%	-3.9%	-3.5%	40.0%				13.5%
C		-2.5%	-1.6%	0.4%	0.9%	-2.3%		1.5%
G		-0.3%		-0.5%				0.4%
H	6.1%		4.9%	31.3%	9.7%			12.9%
M	5.0%	2.0%	-1.5%	3.1%	0.2%	22.0%		5.6%
N	-0.7%	-0.6%	-3.7%	-3.3%	-4.2%	-8.1%		3.4%
O		-0.4%	-1.0%	-2.3%	-3.3%	-3.7%	0.1%	1.8%
Sample Average								**5.6%**
		Outlier removed						

Table A4-5: Commercial Demand Forecasting Accuracy for Sample Group

Commercial Demand	2009	2010	2011	2012	2013	2014	2015	MAPE
B	3.9%	6.6%	0.4%	2.6%				3.4%
C		4.1%		3.7%				3.9%
G	2.1%	6.7%	7.3%	6.6%	9.9%	0.3%		5.5%
H	9.2%		3.6%		8.8%			7.2%
M		7.8%	5.4%	3.2%	7.1%	1.9%		5.1%
N	15.2%	2.4%	1.8%	1.2%	1.2%	6.1%		4.7%
O		4.1%	4.4%	3.9%	6.6%	6.8%	1.2%	4.5%
Average								**4.9%**
		Outlier removed						

Averaging the two ITRON survey results with the Boreas results shown in the tables above results in the following summary.

Table A4-6: Demand Forecasting Accuracy Summary

Demand Forecast MAPE	Boreas (2009-2015)	ITRON 2014	ITRON 2015	Avg Error
Residential Demand	5.6%	2.9%	3.7%	4.1%
Commercial Demand	4.9%	4.0%	3.3%	4.1%

The averages provide a range of the level of accuracy that should be expected and considered reasonable from the demand forecasts. Based on the results reported above, FEI concludes that an aggregate demand variance of 4% (rounded down from the results shown in Table A4-6) is a reasonable target for both residential and aggregated commercial rate schedules for utilities.

4.3 *FEI PERFORMANCE RELATIVE TO SAMPLE GROUP*

The 2009-2015 demand variance results for FEI follow, showing that FEI's 2009 to2015 MAPE for the residential rate group is 1.1 percent and FEI's 2009 to 2015 MAPE for the commercial rate group is 2.4 percent.

The over and under forecasting results are also shown in Tables A4-7 and A4-8. In three of the seven years, the residential demand was over-forecast (two of seven years for commercial). The aggregate error is also shown and for the residential rate group is only 0.3 PJs over seven years. This amounts to an actual percent error of 0.06%.

Table A4-7: Residential Demand Forecasting Accuracy for FEI

FEI Residential Demand (PJ)	2009	2010	2011	2012	2013	2014	2015	2009-2015 MAPE	2009-2015 Sum
Forecast Demand (PJ)	73.8	74.3	73.8	74.7	74.6	74.2	73.1		518.5
Actual Demand (PJ)	74.8	75.0	73.9	74.5	72.7	73.2	74.1		518.2
Error (PJ)	-1.0	-0.7	-0.1	0.2	1.9	1.0	-1.0		0.3
Percent Error	-1.3%	-0.9%	-0.1%	0.3%	2.6%	1.4%	-1.3%	1.1%	0.06%
Over/under Forecast	↓	↓	↓	↑	↑	↑	↓		

Table A4-8: Commercial Demand Forecasting Accuracy for FEI

FEI Commercial Demand (PJ)	2009	2010	2011	2012	2013	2014	2015	2009-2015 MAPE	2009-2015 Sum
Forecast Demand (PJ)	49.0	53.2	53.8	53.2	53.5	56.3	55.6		374.6
Actual Demand (PJ)	53.0	52.5	54.0	54.7	53.6	54.0	55.8		377.6
Error (PJ)	-4.0	0.7	-0.2	-1.5	-0.1	2.3	-0.2		(2.97)
Percent Error	-7.5%	1.3%	-0.4%	-2.7%	-0.2%	4.3%	-0.3%	2.4%	-0.79%
Over/under Forecast	↓	↑	↓	↓	↓	↑	↓		

In both residential demand and commercial demand, the performance of the current FEI methods over the seven year period from 2009 to 2015 exceeds the average performance of the sample group shown in Table A4-6. FEI does not believe that the exact numeric differences between the FEI scores and the sample group averages are important, but the fact that FEI's current methods consistently outperform the sample group of utilities is significant. Any changes to use rate and customer forecast methods must be evaluated based on their ability to improve on this result.

5. ALTERNATIVE FORECASTING METHODS

Based on FEI's forecasting experience, Conference Board of Canada (CBOC) forecasts and academic texts, including *Forecasting Methods and Applications*, *Forecasting Principles and Practice*[14], *Predictive Analytics: Microsoft Excel*[15] and *Forecasting with Exponential Smoothing*,[16] FEI developed a list of alternate forecasting methods that included both time series methods and econometric regressions. Including FEI's existing method, the seven methods are:

1. FEI's Existing Method;
2. Holt's Exponential Smoothing (ETS);
3. Time Series Linear Regression;
4. Naïve Forecast;
5. Three Year Moving Average with Trend;
6. Econometric Regression; and
7. Three Year Average.

FEI has tested and compared the six alternate forecasting methods to its existing method. The following sections describe the Existing Method and each of the alternate methods, as well as the pros and cons of each.

5.1 DESCRIPTION OF ALTERNATE METHODS

All alternate time series methods (tests 1 through 5 and 7 above) were used in FEI's Forecasting Information System (FIS) to prepare demand forecasts for comparison to FEI's Existing Method. For Method 6, Econometric Regression, owing to the larger number of econometric variables, unit tests were first performed and only those that passed statistical significance testing and performed better than the Existing Method were implemented in FIS to prepare demand forecasts for comparison to FEI's Existing Method.

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[14] Hyndman, R. J., & Athanasopoulos, G. (2014). Forecasting: Principles and Practice. Chapters 4, 6 and 7

[15] Carlberg, C. G. (2013). Predictive Analytics: Microsoft Excel. Indianapolis, Ind: Que Pub. Chapters 2-4

[16] Hyndman, R. J. (2008). Forecasting with exponential smoothing: The state space approach. Berlin: Springer. Part I.

Table A4-9: Method 1 - Existing

Abbreviation	Existing
Description	The set of methods currently in use by FEI.
Pros	• Well understood • Implemented • Many years of experience/fine tuning • Demand forecast results are consistently better than sample group average
Cons	• Better performing methods may exists for different components of the forecast (e.g. use rate and customer additions).
Testing method	This is the reference case against which other methods are compared.
Reference	Appendix A3 of the 2016 Annual Review for 2016 Rates

Table A4-10: Method 2 - Holt's Exponential Smoothing

Abbreviation	ETS
Description	A method that uses the entire data set (all available data) but weights recent data more heavily than older data. Several different versions exist: • Holt's method accounts for trend (if it exists) and was tested as part of this investigation.
Pros	• Uses the full data series. • Incorporates both recent and historic data while weighting recent data more heavily. • Exponential Smoothing was recently introduced as a new forecasting feature in Microsoft Excel 2016, making it easily accessible to FEI, the Commission and interveners for testing and verification. • The method is inexpensive for FEI to implement and does not require any changes to FIS.
Cons	• Exponential Smoothing is a new feature in Excel 2016, and time is required for the market to confirm that it is stable. • FEI is not aware of any utility using the ETS method in its demand forecasts.
Reference	*Forecasting Methods and Applications, Chapter 4* *Predictive Analytics: Microsoft Excel, Chapter 4*
Testing method	Implemented in FIS demand forecasts for four years (2012-2015).

Table A4-11: Method 3 - Time Series Linear Regression

Abbreviation	TSLR
Description	A least squares model using years as the independent variable and the quantity being forecast as the dependent variable.
Pros	• Well understood • Easy to implement • Uses the full data series • Can be easily evaluated for statistical significance using coefficient of determination (R^2) and F statistics. • Many built in functions support regression calculations in Excel. These are well understood and efficiently implemented.
Cons	• Data is not weighted based on proximity to the test period, so all data points are equally important.
Reference	*Forecasting Methods and Applications, Chapter 5*
Testing method	Implemented in FIS demand forecasts for four years (2012-2015).

Table A4-12: Method 4 -Naïve Forecast

Abbreviation	Naïve
Description	The forecast is simply the most recent available actual data.
Pros	• Easy to implement • Most useful where actual data is very volatile and a trend does not exist.
Cons	• Only uses one year of historical data. • In two year RRA forecasts where there is a seed year, the second forecast year is based on data that is three years old. As there is no trend, the same value is used for the seed year and both forecast years. By the second forecast year variances can become very large.
Reference	*Forecasting Methods and Applications, Section 2.4.3*
Testing method	Implemented in FIS demand forecasts for four years (2012-2015).

Table A4-13: Method 5 - Three Year Moving Average with Trend

Abbreviation	Smooth/Trend
Description	In this combination method, historic data is first smoothed using a three year average. For example, the smoothed 2012 value is the average of 2011, 2012 and 2013. 2012 is the center of the average. The average is recalculated for each year. The final year uses a two year average. Once the smoothed data is developed a time series linear regression is performed to account for the trend and to develop the forecast values.

Abbreviation	Smooth/Trend
Pros	• Easy to implement • Removes some variability in the historical data, particularly in rate classes with fewer customers. • Uses the full data series • Able to forecast trends
Cons	• Relies on a linear regression which equally emphasizes both new and old data points.
Reference	*Predictive Analytics: Microsoft Excel, Chapter 3*
Testing method	Implemented in FIS demand forecasts for four years (2012-2015).

Table A4-14: Method 6 - Econometric Regressions

Abbreviation	Retail Sales
Description	The CBOC prepares provincial forecasts of 11 different variables on an annual basis[17]. Both use rate and customer additions forecasts were prepared using each variable as the regressor. Regression statistics were computed for each regression as follows: • Coefficient of Determination, R^2While there is no standard for R^2, larger values are preferred. For the purposes of this study, explanatory variables that resulted in R^2 values below 60 percent were excluded from further testing. • F Test: The F statistic was calculated at a 95 percent probability. Explanatory variables scoring less than the critical value at this level of probability are statistically insignificant and were also excluded from further testing. • Unit tests using the CBOC forecasts were prepared using standard regression techniques. Variables that were able to produce a lower four year MAPE score than the existing methods were then used in full FIS integration tests (see section 6 below). Variables that failed one or more statistical tests or did not perform as well as the existing forecasts were not used in integration tests. Only the Retail Sales data was able to produce a residential use rate forecast that both passed the statistical tests and performed better than the existing method. All regressors failed the T test at the 95% confidence limit for both commercial use rate and commercial customer additions. For econometric methods, only the Retail Sales variable was carried forward for testing and comparison to the other alternate methods, and for Residential use rate only.
Pros	• Easy to implement • Widely available forecasts (e.g. CBOC)

[17] See Appendix C for a definitions of the regressors tested.

Abbreviation	Retail Sales
Cons	• Places reliance on an external forecast. Any errors in the external forecast will then be incorporated into the FEI forecast. • More widely accepted as a method for long term forecasting
Reference	*Forecasting Methods and Applications, Chapter 5* *Forecasting Principles and Practice, Chapter 4*
Testing method	All explanatory variables were unit tested against residential and commercial use rate, commercial customers and commercial customer additions. Only one variable passed basic statistical tests and also performed better than the Existing Method. This variable was further tested in FIS demand forecasts.

Table A4-15: Method 7 - Three Year Average

Abbreviation	3 Yr Avg
Description	This method takes a three year moving average. The forecast is then assumed to be constant for the test period.
Pros	• Easy to implement • Removes some variability in the historic data, particularly in rate classes with fewer customers.
Cons	• Does not forecast a trend if one is present.
Reference	*Forecasting Methods and Applications, Section 3-2*
Testing method	Implemented in FIS demand forecasts for four years (2012-2015).

5.1.1 Model Usage

The following table indicates which models were tested for each forecast component.

Table A4-16: Forecasting Methods Applied to Components of Forecast

Model	Residential Use Rate	Commercial Use Rate	Commercial Customer Additions	Commercial Customers
Existing	✓	✓	✓	Commercial customers forecasting is not part of the Existing Method. See 3 Yr. Avg. below.
ETS	✓	✓	✓	✓
TSLR	✓	✓	✓	✓
Naïve	✓	✓	✓	✓
3 Yr Avg with Trend	✓	✓	✓	✓

Model	Residential Use Rate	Commercial Use Rate	Commercial Customer Additions	Commercial Customers
Econometric (Retails Sales)	✓	Failed statistical significance testing	Failed statistical significance testing	Failed statistical significance testing
3 Yr. Avg	Included in Existing Method	Included in Existing Method	Included in Existing Method	✓

6. ALTERNATIVE METHOD TESTING

6.1 *TESTING STRATEGY*

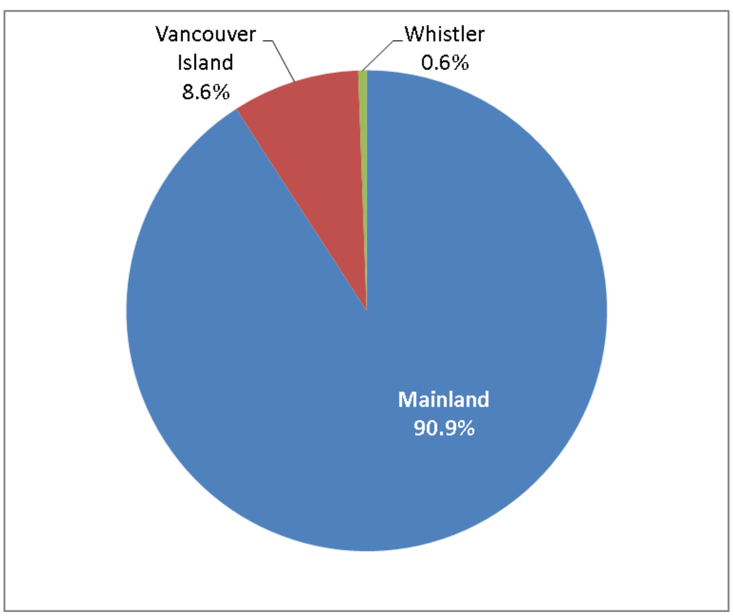
The demand forecast for all residential and commercial rate schedules is the product of a customer forecast and a use rate forecast.

FIS forecasts were created to test each component (residential use rates, commercial use rates, commercial customer additions) independently. Only one component was changed for each run so that the impact of a single change could be measured. For example, in a residential use rate test all other components of the FIS forecast were unchanged from the forecasts as filed and only the residential use rates were changed. This test strategy required the creation of more than 80 different FIS forecasts as well as the design and development of new FIS data input software created specifically for this project. Once each forecast re-calculation was complete any changes in the APE value compared to the Existing forecast were known to be directly related to the single forecast component that was changed.

6.2 *TEST DATA*

The Mainland region was used for testing forecast performance of each alternate method. Mainland was chosen for testing because the region accounts for more than 90 percent of FEI demand and because the rate schedules for FEI have been stable over time.

Figure A4-1: FEI Demand by Region



While Vancouver Island does account for nearly 9 percent of FEI demand, the data is difficult to use for testing because of the pre- and post-amalgamation mix. For example, it is challenging to prepare a long time series regression on Vancouver Island Rate Schedule 3 because Rate Schedule 3 is new to Vancouver Island customers and mapping the old FortisBC Energy Vancouver Island (FEVI) rate classes would result in forecast errors not related to the alternate methods.

In all alternative method tests, detailed, weather normalized historical data was available from 2004 through 2015 (12 years). A minimum of seven years was used for establishing forecast model parameters (the initialization set). The remaining years (2012-2014) were used for model evaluation (the test set). Results from the test set alternate forecasts were then compared to the actual data recorded for those years.

The following table identifies the years where tests were completed as well as the initialization data used:

Table A4-17: Forecasting Test Years[18]

Initialization Data	Seed Year	Forecast Year	Filing
2004-2010	2011	2012	2012-2013 RRA
2004-2010	2011	2013	2012-2013 RRA
2004-2012	2013	2014	2014 PBR
2004-2013	2014	2015	Annual Review for 2015 Rates

CBOC data was selected from the CBOC forecast reports that were available when the forecast would have been prepared. FEI was careful to ensure that alternate methods did not have access to data that would not have been available when the original forecasts were prepared.

6.3 *TEST RESULTS*

Consistent with the directives discussed in section two, three sets of tests were completed as shown in Table A4-18 below. In addition, a fourth test was completed by forecasting commercial customers directly, instead of customer additions.

[18] The same initialization data set was used for the 2012 and 2013 forecasts because those two years were forecast and filed together.

Table A4-18: Tests

1	Residential use rate	Alternate methods were applied to forecast the Rate Schedule 1 use rate in each Mainland sub-region. The residential customer forecasts were maintained consistent with the customer forecasts filed for each of the four test years.
2	Commercial use rates	Alternate methods were applied to forecast the Rate Schedule 2, 3 and 23 use rates in each Mainland sub-region. The customer forecasts were maintained consistent with the customer forecasts filed for each of the four test years. Each alternate method was applied consistently to all rate schedules and sub-regions.
3	Commercial customer additions	Alternate methods were applied to forecast the Rate Schedule 2, 3 and 23 customer additions in each Mainland sub-region. The use rate forecasts were maintained consistent with the use rate forecasts filed for each of the four test years. Each alternate method was applied consistently to all rate schedules and sub-regions.
4	Commercial customers	Alternate methods were applied to forecast the Rate Schedule 2, 3 and 23 customers in each Mainland sub-region. The use rate forecasts were maintained consistent with the use rate forecasts filed for each of the four test years. Each alternate method was applied consistently to all rate schedules and sub-regions.

6.4 *DESCRIPTION OF RESULTS TABLES*

The results tables used in this section all follow the same format, with the following columns:

1	2	3	4	5	6	7	8
Year	**UPC Method**	**Customers Method**	**Demand Forecast Method UPC X Customers**	**Forecast Demand**	**Actual Demand (PJs)**	**APE**	**4 Yr. MAPE**

An explanation of each column is provided in Table A4-19 below.

Table A4-19: Explanation of Columns in Results Tables

Column	Explanation
1	The year being forecast for the particular row. 2012, 2013, 2014 and 2015 were all reforecast in all tests.
2	Column two shows the use rate method used for the row.
3	Column three shows the method used to forecast the customers.
4	Column four shows the formula used to calculate demand.
5	Column five shows the demand forecast resulting from the methods shown in column four.
6	Column six shows the actual normalized demand recorded for the year reported in column one.
7	Column seven shows the single year absolute percent error (APE).
8	Column eight shows the four year mean absolute percent error (MAPE).

6.5 ALTERNATE FORECASTS FOR RESIDENTIAL USE RATE

For this series of tests the Existing Method for forecasting customer additions was used in all forecast runs (column 3). The method used to forecast the residential use rate was changed to one of the five alternate methods applicable for Residential use rate (column 2). The alternate methods were applied consistently in the Lower Mainland, Inland and Columbia sub-regions. FIS forecasts for each sub-region were built and an FIS model run was completed for each combination. The scores in the table below are the APE scores from the resulting demand forecasts.

Table A4-20: Alternate Forecasts for Residential Use Rate

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast Demand	Actual Demand (PJs)	APE	4 Yr. MAPE
2012	Existing	Existing	Existing X Existing	69.9	69.8	0.1%	
2013	Existing	Existing	Existing X Existing	69.8	68.1	2.5%	
2014	Existing	Existing	Existing X Existing	69.5	68.5	1.5%	
2015	Existing	Existing	Existing X Existing	68.5	68.9	0.6%	1.2%
2012	ETS	Existing	ETS X Existing	68.4	69.8	2.1%	
2013	ETS	Existing	ETS X Existing	67.6	68.1	0.7%	
2014	ETS	Existing	ETS X Existing	68.9	68.5	0.6%	
2015	ETS	Existing	ETS X Existing	67.6	68.9	1.9%	1.3%
2012	TSLR	Existing	TSLR X Existing	67.7	69.8	3.0%	
2013	TSLR	Existing	TSLR X Existing	67.5	68.1	0.9%	
2014	TSLR	Existing	TSLR X Existing	67.2	68.5	1.9%	
2015	TSLR	Existing	TSLR X Existing	67.4	68.9	2.2%	2.0%
2012	Naïve	Existing	Naïve X Existing	71.3	69.8	2.1%	
2013	Naïve	Existing	Naïve X Existing	71.8	68.1	5.4%	
2014	Naïve	Existing	Naïve X Existing	70.6	68.5	3.1%	
2015	Naïve	Existing	Naïve X Existing	69.5	68.9	0.9%	2.9%
2012	Smooth/Trend	Existing	Smooth/Trend X Existing	68.2	69.8	2.3%	
2013	Smooth/Trend	Existing	Smooth/Trend X Existing	67.6	68.1	0.7%	
2014	Smooth/Trend	Existing	Smooth/Trend X Existing	67.1	68.5	2.0%	
2015	Smooth/Trend	Existing	Smooth/Trend X Existing	67.8	68.9	1.6%	1.7%
2012	Retail Sales	Existing	Retail Sales X Existing	70.5	69.8	1.0%	
2013	Retail Sales	Existing	Retail Sales X Existing	70.0	68.1	2.9%	
2014	Retail Sales	Existing	Retail Sales X Existing	67.5	68.5	1.5%	
2015	Retail Sales	Existing	Retail Sales X Existing	65.8	68.9	4.5%	2.5%

A description of the results of the various methods is provided in the following table.

1 **Table A4-21: Summary of Residential Use Rate Methods**

Use Rate Method	Comments
Existing	The four year residential demand MAPE resulting from the current methods is 1.2% for the Mainland region. 2015 was the second best year of the four year period where the APE was 0.6%. Of the four years tested, only 2012 performed better than 2015 where the APE was just 0.1%.
ETS	The ETS forecast performed well for residential use rate, resulting in the lowest four year MAPE score of all the alternate methods tested at 1.3%.
TSLR	The time series linear regression performed reasonably well, but not as well as other methods including the ETS method. This is normally to be expected because the TSLR method assigns equal emphasis to all data points whereas the ETS method weights more recent data more heavily. Other than the naïve model and the econometric regression the 2015 TSLR score was the worst of all methods tested. The four year MAPE was 2.0%.
Naïve	The naïve forecast was the worst performing of the alternative methods with a four year MAPE of nearly 3.0%. Recent performance was good, but the APE was over 5% for the 2013 forecast which was the worst result in this set of tests, and one of only two that performed more poorly than the sample group average.
Smooth/Trend	Smoothing the historic data and then applying a trend to the smoothed data points was able to produce a better forecast than the TSLR method alone. In this case smoothing the data before using a simple regression resulted in a 4-year MAPE of 1.7% compared to the TSLR-only forecast MAPE of 2.0%. The improvement was not significant enough to exceed the results obtained by either the ETS or Existing methods.
Retail Sales	Residential use rate was found to correlate well to retail sales. The regression statistics were all strong and the F test indicated that the regression was statistically significant at the 95% confidence limit. However the resulting demand forecast was only slightly better than the naïve forecast, and performed poorly compared to the other time series based methods. These finding are consistent with the results of a 1978 study of 30 tests which showed that econometric methods did not perform better than time series methods.[19]
Summary	Over a four year period all the methods including the Existing Method outperformed the sample group average. The Existing Method performed the best, but the four year average for the ETS method was only one tenth of a percent lower. The ETS method produced consistently good results and had the lowest four-year MAPE of all the alternate methods tested. In two of the four test years the Existing Method outperformed the ETS method.

2 6.6 *ALTERNATE FORECASTS FOR COMMERCIAL USE RATE*

3 For this series of tests the Existing Method for forecasting customer additions was used in all
4 forecast runs (column 3). The method used to forecast the commercial use rate was changed to
5 one of the four alternative methods (column 2). The alternative methods were applied
6 consistently to all commercial rate schedules in the Lower Mainland, Inland and Columbia sub-
7 regions. FIS forecasts for each commercial rate schedule and sub-region were built and an FIS

[19] *Forecasting Methods and Applications*, section 11/2, page 525.

model run was completed for each combination. The scores in the table below are the APE scores from the resulting demand forecasts.

Table A4-22: Alternate Forecasts for Commercial Use Rate

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast Demand	Actual Demand (PJs)	APE	4 Yr. MAPE
2012	Existing	Existing	Existing X Existing	47.1	48.8	3.4%	
2013	Existing	Existing	Existing X Existing	47.3	48.1	1.6%	
2014	Existing	Existing	Existing X Existing	50.2	48.8	3.0%	
2015	Existing	Existing	Existing X Existing	49.3	49.1	0.5%	2.2%
2012	ETS	Existing	ETS X Existing	48.1	48.8	1.4%	
2013	ETS	Existing	ETS X Existing	48.5	48.1	0.8%	
2014	ETS	Existing	ETS X Existing	48.5	48.8	0.5%	
2015	ETS	Existing	ETS X Existing	49.1	49.1	0.0%	0.7%
2012	TSLR	Existing	TSLR X Existing	48.1	48.8	1.5%	
2013	TSLR	Existing	TSLR X Existing	48.5	48.1	0.8%	
2014	TSLR	Existing	TSLR X Existing	48.2	48.8	1.2%	
2015	TSLR	Existing	TSLR X Existing	49.0	49.1	0.2%	0.9%
2012	Naïve	Existing	Naïve X Existing	47.4	48.8	2.9%	
2013	Naïve	Existing	Naïve X Existing	47.7	48.1	0.9%	
2014	Naïve	Existing	Naïve X Existing	49.1	48.8	0.6%	
2015	Naïve	Existing	Naïve X Existing	48.5	49.1	1.3%	1.4%
2012	Smooth/Trend	Existing	Smooth/Trend X Existing	48.5	48.8	0.6%	
2013	Smooth/Trend	Existing	Smooth/Trend X Existing	49.0	48.1	1.9%	
2014	Smooth/Trend	Existing	Smooth/Trend X Existing	48.2	48.8	1.3%	
2015	Smooth/Trend	Existing	Smooth/Trend X Existing	49.2	49.1	0.3%	1.0%

Table A4-23: Summary of Commercial Use Rate Methods

Use Rate Method	Comments
Existing	The four year MAPE resulting from the Existing Method is 2.2% for the Mainland region. 2015 was the best year of the four year period where the APE was just 0.5%. The Existing method did not perform as well as the alternatives. However, the MAPE score was still well below the 4% average of the sample group.
ETS	The ETS forecast performed well for commercial use rates, resulting in the lowest four year MAPE score of all the methods tested at less than 1%. In 2015 the ETS method accurately predicted the commercial use rate and the APE was 0%. This was the best score of all the tests in this study.
TSLR	The time series linear regression performed well, but not as well as the ETS method. This is normally to be expected because the TSLR method weights all data points equally whereas the ETS method weights more recent data more heavily.
Naïve	A naïve forecast was not able to perform at the same level as the more rigorous ETS and TSLR methods. Recent performance was good, but the forecast for 2012 was one of the worst in this set of tests.

Use Rate Method	Comments
Smooth/Trend	Smoothing the historical data and then applying a trend to the smoothed data points can produce a better forecast than the TSLR method. In this case the TSLR forecast performed well and the smoothing step used here was not able to improve on the result.
Summary	All the methods including the Existing Method outperformed the sample group average. The ETS method produced consistently low APE results and had the lowest 4 year MAPE of all the methods tested. While the MAPE for the Existing Method was the highest of all the methods tested, it was still just over half the sample group average.

6.7 *ALTERNATE FORECASTS FOR COMMERCIAL CUSTOMER ADDITIONS*

For this series of tests the Existing Method for forecasting use rates was used in all forecast runs (column 2). The method used to forecast the commercial customer additions was changed to one of the four alternative methods (column 3). The alternative methods were applied consistently to all commercial rate schedules in the Lower Mainland, Inland and Columbia sub-regions. FIS forecasts for each commercial rate schedule and sub-region were built and an FIS model run was completed for each combination. The scores in the table below are the APE scores from the resulting demand forecast.

1 **Table A4-24: Alternate Forecasts for Commercial Customer Additions**

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Additions Method	Demand Forecast Method UPC X Customers	Forecast Demand	Actual Demand (PJs)	APE	4 Yr. MAPE
2012	Existing	Existing	Existing X Existing	47.1	48.8	3.4%	
2013	Existing	Existing	Existing X Existing	47.3	48.1	1.6%	
2014	Existing	Existing	Existing X Existing	50.2	48.8	3.0%	
2015	Existing	Existing	Existing X Existing	49.3	49.1	0.5%	2.2%
2012	Existing	ETS	Existing X ETS	46.2	48.8	5.3%	
2013	Existing	ETS	Existing X ETS	46.7	48.1	3.0%	
2014	Existing	ETS	Existing X ETS	50.3	48.8	3.1%	
2015	Existing	ETS	Existing X ETS	48.8	49.1	0.5%	3.0%
2012	Existing	TSLR	Existing X TSLR	46.1	48.8	5.5%	
2013	Existing	TSLR	Existing X TSLR	46.6	48.1	3.2%	
2014	Existing	TSLR	Existing X TSLR	50.4	48.8	3.4%	
2015	Existing	TSLR	Existing X TSLR	48.9	49.1	0.3%	3.1%
2012	Existing	Naïve	Existing X Naïve	45.6	48.8	6.5%	
2013	Existing	Naïve	Existing X Naïve	45.8	48.1	4.9%	
2014	Existing	Naïve	Existing X Naïve	49.8	48.8	2.2%	
2015	Existing	Naïve	Existing X Naïve	48.8	49.1	0.6%	3.6%
2012	Existing	Smooth/Trend	Existing X Smooth/Trend	45.8	48.8	6.1%	
2013	Existing	Smooth/Trend	Existing X Smooth/Trend	46.0	48.1	4.4%	
2014	Existing	Smooth/Trend	Existing X Smooth/Trend	50.2	48.8	3.0%	
2015	Existing	Smooth/Trend	Existing X Smooth/Trend	48.8	49.1	0.6%	3.5%
2012	Existing	3 yr avg customers	Existing X 3 yr avg customers	45.8	48.8	6.1%	
2013	Existing	3 yr avg customers	Existing X 3 yr avg customers	46.0	48.1	4.4%	
2014	Existing	3 yr avg customers	Existing X 3 yr avg customers	50.2	48.8	3.0%	
2015	Existing	3 yr avg customers	Existing X 3 yr avg customers	48.7	49.1	0.8%	3.6%

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4 **Table A4-25: Summary of Commercial Customer Additions Methods**

Customers Method	Comments
Existing	The four-year MAPE resulting from the current methods is 2.2% for the Mainland region. 2015 was the best year of the four-year period where the APE was 0.5%. The Existing method outperformed all alternate methods over the four-year period.
ETS	The ETS forecast did not perform as well as the Existing Method for commercial customer additions. The four-year MAPE was 3.0% compared to 2.2% for the Existing Method. As with all methods tested, performance in 2015 was better than other years and in the case of the ETS method the 2015 APE was below 1%. However the strong performance in 2015 was offset by poor results in 2012 and 2013 when the APE scores exceeded 3%.
TSLR	The time series linear regression performed reasonably well, and other than the ETS method was the best performing alternate method. However, the four-year MAPE score is nearly 1% higher than the Existing Method.

Customers Method	Comments
Naive	The naïve forecast method was the worst performing alternate method and the four-year MAPE score was 1.4% higher than the Existing Method. Recent performance was better but the demand forecast APE for 2011 and 2012 exceeded 5% in both years.
Smooth/Trend	Smoothing the historic data and then applying a trend to the smoothed data points produced an inferior forecast to using the TSLR method alone. This is not intuitive and contrary to the results seen in the use rate forecast tests.
Summary	All methods tested resulted in MAPE scores lower than the sample group average. The Existing Method outperformed all the alternate methods over the four years that were tested. All the alternate methods were grouped between MAPE results of 3.0% to 3.6% while the Existing Method was lower at 2.2%. ETS was the best performing alternate method at 3.0%. FEI believes that the generally higher MAPE values compared to the use rate forecast results are a result of the volatility in the actual commercial additions data.

6.8 *ALTERNATE FORECASTS FOR TOTAL COMMERCIAL CUSTOMERS*

FEI tried the same set of alternate methods to forecast total customers instead of customer additions (as is done for the FortisBC Inc. commercial forecast). While the variability (standard deviation) in the historical customer data is lower than it is in the customer additions data, none of the methods were able to produce a better demand forecast than the Existing Method. The table of results is included for completeness, but will not be discussed further in this Report.

Table A4-26: Alternate Forecasts for Total Commercial Customers

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast Demand	Actual Demand (PJs)	APE	4 Yr. MAPE
2012	Existing	ETS	Existing X ETS	45.3	48.8	7.3%	
2013	Existing	ETS	Existing X ETS	45.2	48.1	6.1%	
2014	Existing	ETS	Existing X ETS	50.5	48.8	3.5%	
2015	Existing	ETS	Existing X ETS	49.4	49.1	0.6%	4.4%
2012	Existing	TSLR	Existing X TSLR	45.7	48.8	6.5%	
2013	Existing	TSLR	Existing X TSLR	45.8	48.1	4.8%	
2014	Existing	TSLR	Existing X TSLR	51.1	48.8	4.7%	
2015	Existing	TSLR	Existing X TSLR	49.7	49.1	1.2%	4.3%
2012	Existing	Naïve	Existing X Naïve	44.7	48.8	8.5%	
2013	Existing	Naïve	Existing X Naïve	44.3	48.1	7.9%	
2014	Existing	Naïve	Existing X Naïve	49.7	48.8	2.0%	
2015	Existing	Naïve	Existing X Naïve	48.4	49.1	1.4%	4.9%
2012	Existing	Smooth/Trend	Existing X Smooth/Trend	45.7	48.8	6.3%	
2013	Existing	Smooth/Trend	Existing X Smooth/Trend	45.9	48.1	4.6%	
2014	Existing	Smooth/Trend	Existing X Smooth/Trend	51.1	48.8	4.7%	
2015	Existing	Smooth/Trend	Existing X Smooth/Trend	49.7	49.1	1.2%	4.2%
2012	Existing	3 yr avg customers	Existing X 3 yr avg customers	44.3	48.8	9.2%	
2013	Existing	3 yr avg customers	Existing X 3 yr avg customers	44.0	48.1	8.6%	
2014	Existing	3 yr avg customers	Existing X 3 yr avg customers	49.6	48.8	1.7%	
2015	Existing	3 yr avg customers	Existing X 3 yr avg customers	48.3	49.1	1.7%	5.3%

6.9 COMBINATION OF COMMERCIAL USE RATE AND CUSTOMER ADDITION FORECAST METHODS

As discussed above, the ETS method produced the best results of all methods tested for the commercial use rate but not for the commercial customer addition forecasts. To test whether using ETS for both commercial use rate and commercial customer additions would be more accurate than the combination of ETS for commercial use rate and the Existing Method for commercial customer additions, FEI also prepared a forecast using ETS for both commercial use rate and commercial customer additions.

The result was an overall MAPE of 1.0% as shown in Table A4-27 below which was not better than using ETS for commercial use rate and the Existing Method for commercial customer additions (which had a MAPE score of 0.7%).

Table A4-27: ETS Method Used for Commercial Customer Additions and Use Rate

1	2	3	4	5	6	7	8
Year	**UPC Method**	**Customers Additions Method**	**Demand Forecast Method UPC X Customers**	**Forecast Demand**	**Actual Demand (PJs)**	**APE**	**4 Yr. MAPE**
2012	ETS	ETS	ETS X ETS	47.2	48.8	3.2%	
2013	ETS	ETS	ETS X ETS	48.0	48.1	0.2%	
2014	ETS	ETS	ETS X ETS	48.6	48.8	0.4%	
2015	ETS	ETS	ETS X ETS	48.9	49.1	0.4%	1.0%

7. RECOMMENDATION

Of the six alternative forecasting methods tested and compared, ETS is the best performing alternate method and the only alternate method that consistently produced test results in the same range of accuracy as FEI's Existing Method. The fact that the ETS method has recently been implemented in Excel 2016 also makes it an attractive option.

At this time, FEI is recommending that it continue to use the Existing Method and that further testing be completed on the ETS method over the remaining term of the PBR. FEI's recommendation is based on the following:

- FEI's Existing Method has performed well over many years, consistently outperforming the average of the survey sample group in forecasting residential and commercial demand. Based on the data available at this time, FEI's Existing Method remains a reliable and reasonable demand forecasting method for FEI's revenue requirement purposes.
- FEI's testing of ETS results in four data points. While four data points are sufficient to identify potential replacements, they are an insufficient basis on which to recommend the replacement of FEI's Existing Method, which has a proven performance record over more than 10 years.
- The Boreas study did not find evidence of any other utility using ETS. This reinforces the need for further testing to confirm the suitability of the ETS method.
- While the implementation of the method in Excel 2016 makes the method attractive, it is also new and time is required to ensure that the feature will provide a stable basis for FEI's demand forecast.
- FEI believes it is important to apply a consistent method of forecasting to all of its service areas. However, the transition of the Vancouver Island and Whistler service areas to common rates will not be complete until 2018. Due to the changes to available rate schedules in those service areas, FEI will be unable to utilize the ETS method to provide forecasts for those areas until a number of years of comparable data is available. Since the alternate tests cannot be performed for those service areas, the ETS method cannot be applied to all of FEI.
- The remaining term of the PBR provides a good opportunity to continue testing ETS as any variances in the demand forecast are captured in the Flow-through deferral account.

FEI proposes to report the ETS test forecasts and the aggregate MAPE results together in the annual review following when the actual normalized data is available. For example, FEI will provide the 2016 ETS forecast and MAPE results in its Annual Review for 2018 Rates (filed in mid-2017). FEI will make a final recommendation on the forecasting method that should apply to all of its service areas at the end of the PBR term.

Table A4-28 below shows the forecasting methods that will be utilized for the annual review forecasts during the remainder of the PBR term, and the alternate tests that will be performed.

Table A4-28: Roadmap for Remainder of PBR Term

Mainland Forecast	Residential		Commercial		Industrial
	Use Rate	Customer Additions	Use Rate	Customer Additions	
Annual Review	Existing	Traditional (CBOC)	Existing	Existing	Survey
Alternate Test	ETS	Traditional (CBOC)	ETS	ETS and Existing	Survey

Appendix A4-A

ITRON SURVEY RESULTS

ITRON 2014 Survey

Itron published its “2014 Forecasting Benchmark and Outlook Survey” on September 16, 2014, which provides an indication of the average variance between actual and forecast demand for gas utilities. Itron reported that 15 gas utilities participated in the survey (FEI did not participate). Only summary results from the survey are available.

The results from the survey are shown in Table 1 below.

ITRON 2015 Survey

Itron published its “2015 Forecast Accuracy Benchmarking Survey and Energy Trends” on September 15, 2015 (updated February 18, 2016), which provides an indication of the average variance between actual and forecast demand for gas utilities. Itron reported that 9 gas utilities participated in the survey (FEI did not participate). Only summary results from the survey are available.

The results from the survey are shown in Table 1 below.

Table 1: ITRON Survey Summary

Natural Gas Responses (MAPE)

	Against Weather Normalized Actual Values		Against Actual Values
Class	2014 Survey	2015 Survey	2015 Survey
Residential	2.90	3.71	11.36
Commerical	3.95	3.25	10.16
Industrial	6.44	5.03	9.86
System	2.31	3.24	9.62

FEI has utilized the weather normalized actual values in its summary in Table A4-6.

Appendix A4-B

BOREAS SURVEY RESULTS - REDACTED

FortisBC Energy Inc.

Short Term Forecasting – Benchmarking Study

Industry Practices Review

Confidential Appendix A: Utility Key (intentionally omitted)

Appendix B: Forecasting Accuracies – Other Utilities

Appendix C: Utility Data

APPENDIX B: FORECASTING ACCURACIES – OTHER UTILITIES

Utility "A"

Utility "A" presents its forecasts of customer numbers in terms of monthly customer billings. Actual average annual customer counts are therefore roughly one twelfth the number of billings. Commercial customers have exhibited near constant rates of growth over the past several years. An extrapolation of this trend into the future therefore has resulted in highly accurate forecasts. However, the historic trend in UPC has not lent itself well to such a forecasting technique, yielding absolute errors averaging 2.3 and 3.6 percent over the past three years for residential and commercial UPC, respectively.

Figure 1

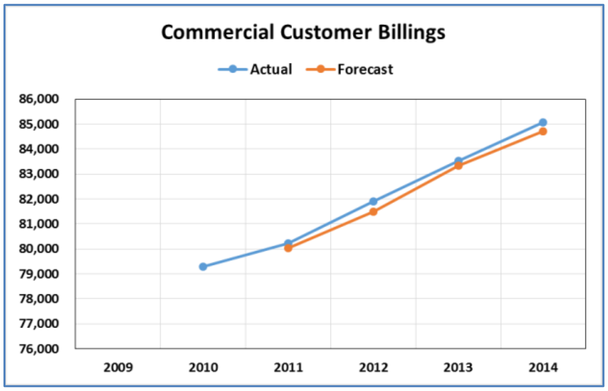


Figure 2

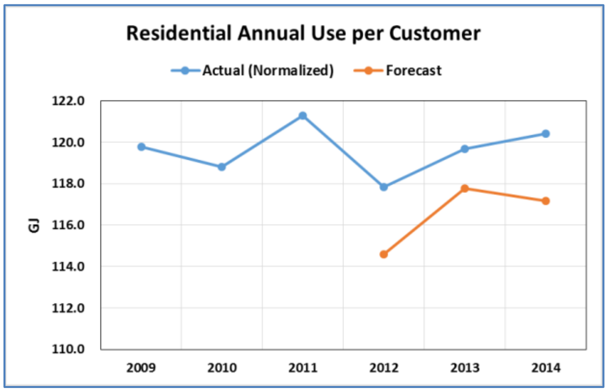


Figure 3

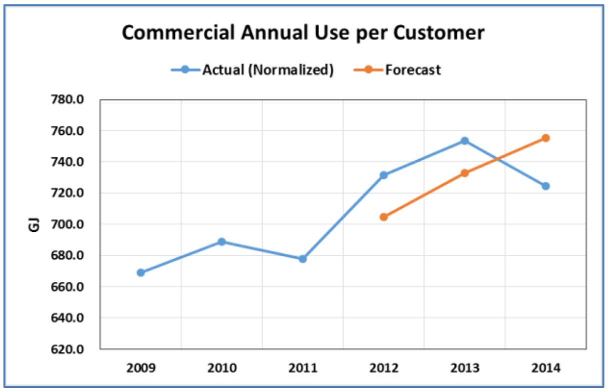


Table 1

SUMMARY STATISTICS FOR THE PERIOD 2011 - 2014		
RESIDENTIAL FORECAST	Customer	UPC
Mean Percentage Error (MPE)		-2.3%
Mean Absolute Percentage Error (MAPE)		2.3%
COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	-0.3%	-0.7%
Mean Absolute Percentage Error (MAPE)	0.3%	3.6%

Utility "B"

An unexpected large decline in residential demand in 2012 has a significant impact on the average absolute error over the period 2009 – 2012. Excluding 2012 from the analysis yields a MAPE for the residential demand forecast of 4.7 percent, comparable to that of the commercial demand forecast over the same period (3.2 percent).

Figure 4

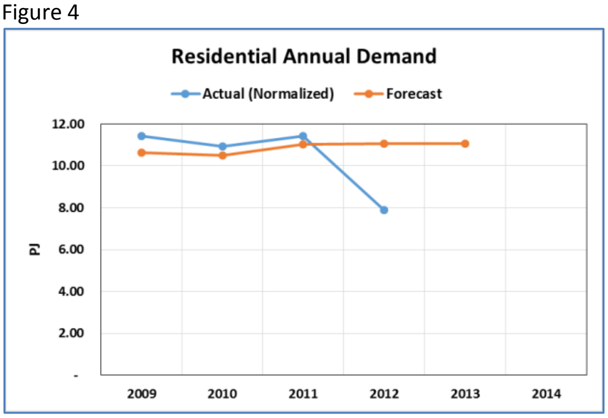


Figure 5

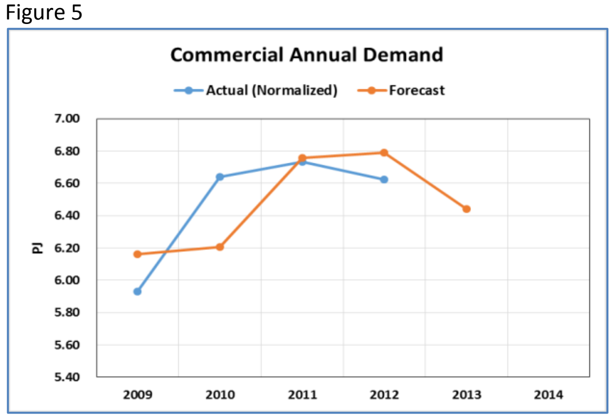


Table 2

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2012		
RESIDENTIAL FORECAST	**Customer**	**Demand**
Mean Percentage Error (MPE)		6.4%
Mean Absolute Percentage Error (MAPE)		13.5%
COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	na	0.1%
Mean Absolute Percentage Error (MAPE)	na	3.4%

Utility "C"

Actual commercial customer counts over the period 2009 to 2014 show monotonic increases year over year (Figure 6, Figure 7). Despite that, Utility "C" has consistently over-forecast small commercial customers and has been unable to reflect the growth in its large commercial customers.

In its periodic natural gas volume forecasts, Utility "C" presents a comparison of its forecast demand, aggregated across all customer classes (with the exception of the special contract and power generation customers), and its actual demand adjusted for weather and heating value. With the exception of the gas year 2011/12, total demand has been over-forecast by an average of 2.0 percent in every year for which data was available (Figure 11).

Figure 6

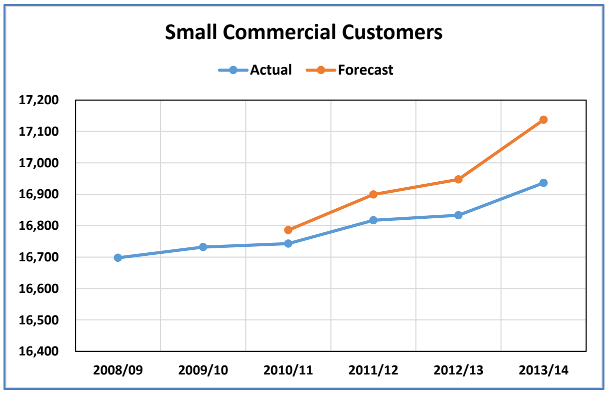


Figure 7

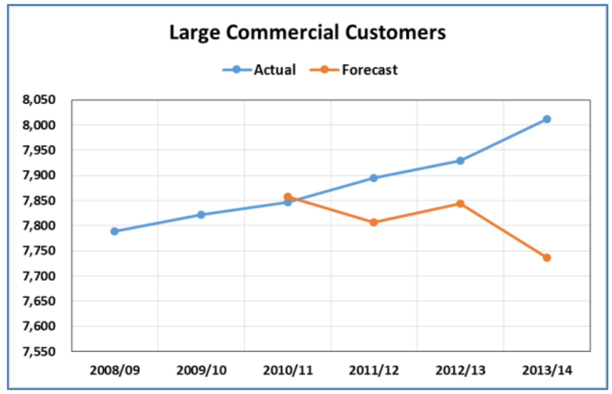


Figure 8

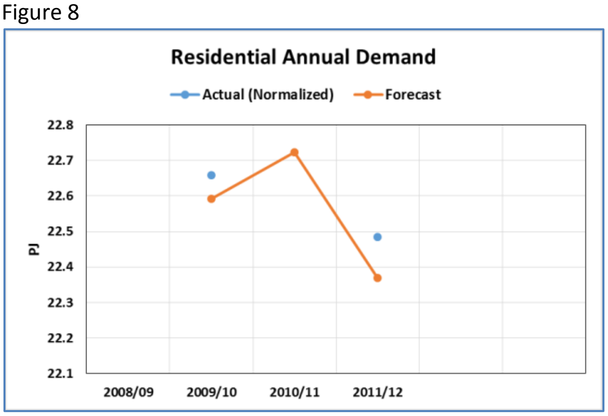


Figure 9

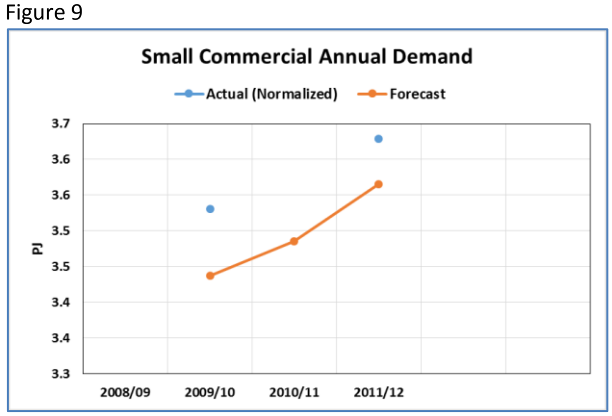


Figure 10

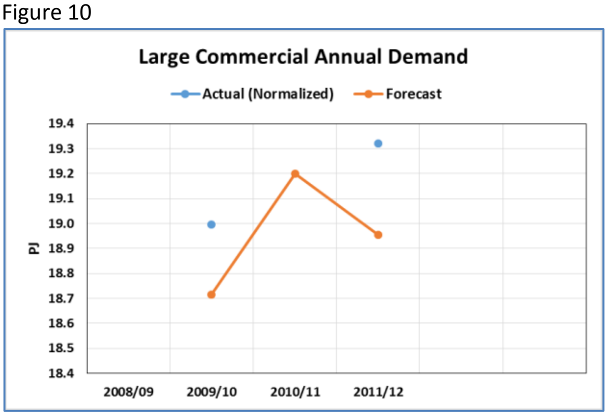


Figure 11

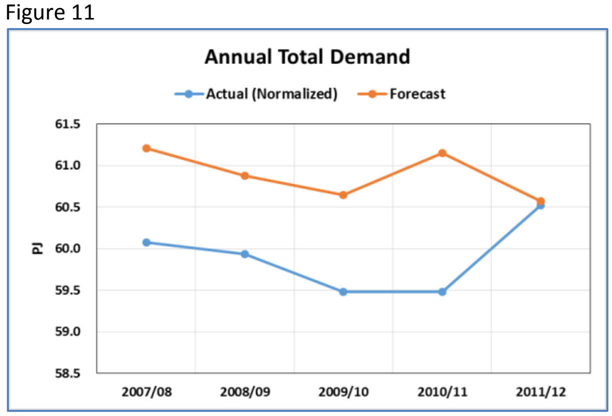


Table 3

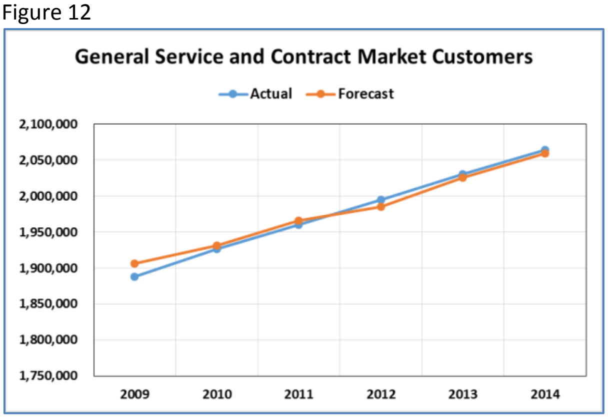
SUMMARY STATISTICS FOR THE PERIOD 2010 - 2014		
RESIDENTIAL FORECAST	Customer	Demand
Mean Percentage Error (MPE)		-0.4%
Mean Absolute Percentage Error (MAPE)		0.4%
SMALL COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	0.7%	-2.2%
Mean Absolute Percentage Error (MAPE)	0.7%	2.2%
LARGE COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	-1.4%	-1.7%
Mean Absolute Percentage Error (MAPE)	1.4%	1.7%
SYSTEM FORECAST		
Mean Percentage Error (MPE)	na	1.7%
Mean Absolute Percentage Error (MAPE)	na	1.7%

Utility "D"

Customer Forecast

Utility "D" presents a comparison of the actual, and the regulator approved forecast customers as part of its rate applications. These results are summarized below. The MAPE of the customer forecast over the period 2009 to 2014 is 0.4 percent.

Figure 12



Use per Customer Forecast

Utility "D" presents a comparison of the actual normalized, and the regulator approved forecast average UPC as part of its rate applications. These results are summarized below. The MAPE of the residential UPC forecast over the period 2010 to 2014 is 1.3 percent, while the MAPE of the General Service UPC forecast is 3.2 percent.

Figure 13

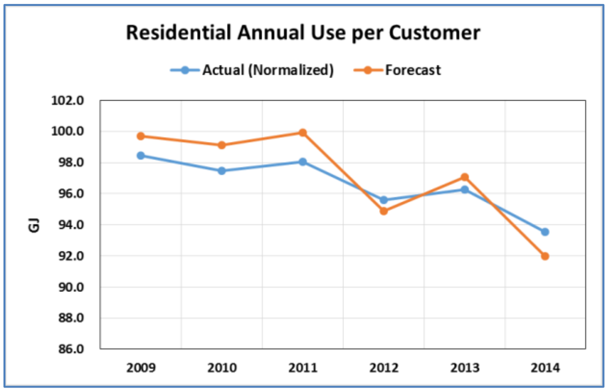


Figure 14

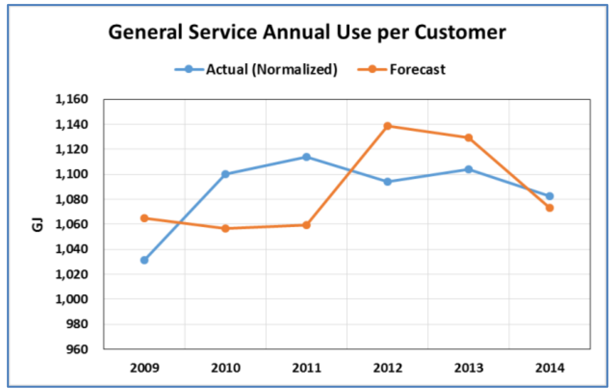


Table 4

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2014		
RESIDENTIAL FORECAST	**Customer***	**UPC**
Mean Percentage Error (MPE)		0.5%
Mean Absolute Percentage Error (MAPE)		1.3%
GENERAL SERVICE FORECAST		
Mean Percentage Error (MPE)	0.1%	0.0%
Mean Absolute Percentage Error (MAPE)	0.4%	3.2%

* All General Service and Contract Market Customers

Utility “E”

Figure 15

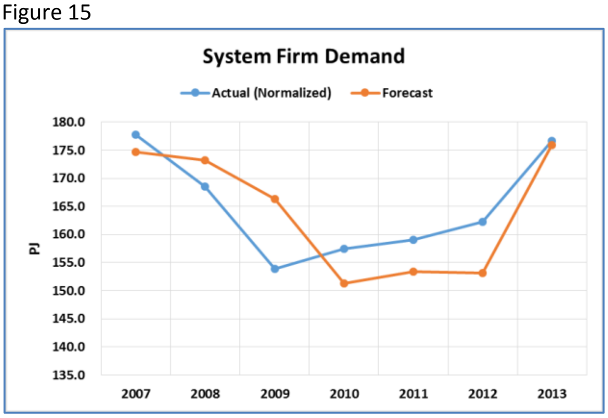


Table 5

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2013		
SYSTEM FIRM FORECAST	**Customer**	**Demand**
Mean Percentage Error (MPE)	na	-1.1%
Mean Absolute Percentage Error (MAPE)	na	4.3%

Utility "F"

The reversal of an exodus of customers to a net influx that began in 2011 has proven difficult for Utility "F" to predict. Despite that, Utility "F" has achieved an average accuracy of 1.7 and 2.3 percent in its customer and demand forecasts, respectively.

Figure 16

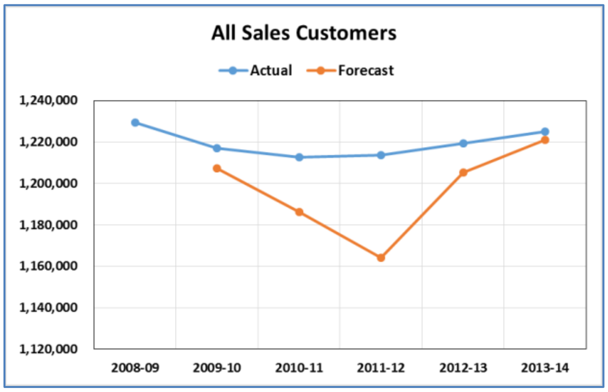


Figure 17

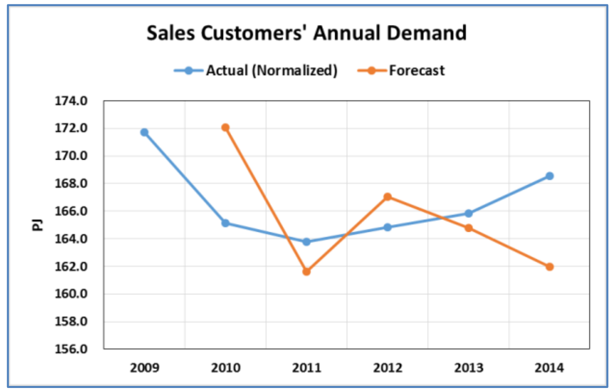


Table 6

SUMMARY STATISTICS FOR THE PERIOD 2010 - 2014		
SYSTEM FORECAST	Customer	Demand
Mean Percentage Error (MPE)	-1.7%	-0.1%
Mean Absolute Percentage Error (MAPE)	1.7%	2.3%

Utility "G"

Figure 18

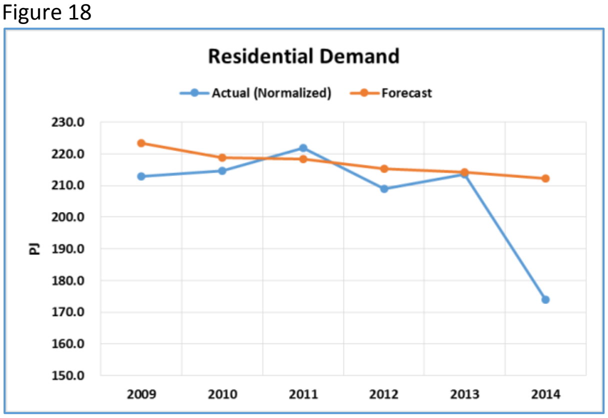


Table 7

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2014		
RESIDENTIAL FORECAST	Customer	Demand
Mean Percentage Error (MPE)		5.1%
Mean Absolute Percentage Error (MAPE)		5.6%

Utility "H"

A comparison of forecast and actual weather normalized demand was compiled from data presented by the utility in its annual resource plan filings (Figure 19, Figure 20). Utility "H" consistently over-forecasted demand from its residential and commercial classes over the period 2008 to 2014 by an average of 13 and 12 percent, respectively.

Figure 19

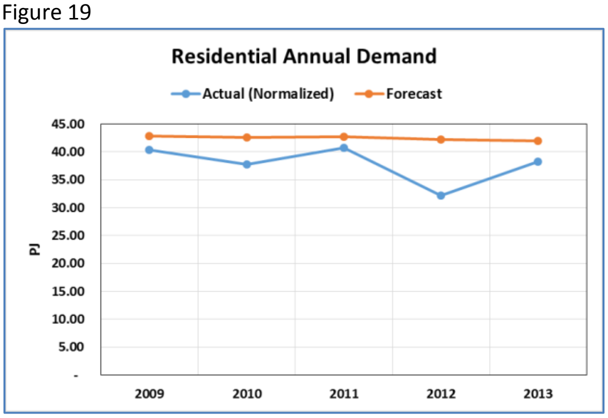


Figure 20

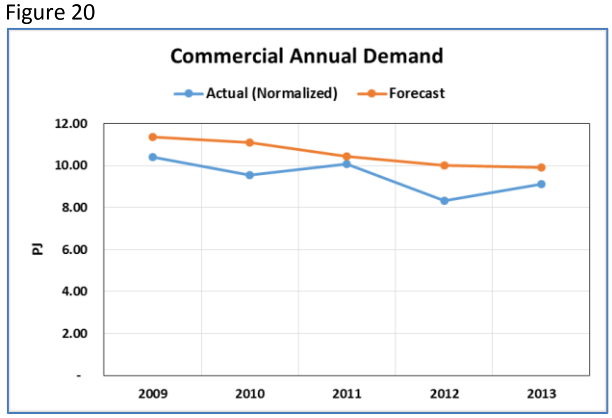


Table 8

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2013		
RESIDENTIAL FORECAST	Customer	Demand
Mean Percentage Error (MPE)		12.9%
Mean Absolute Percentage Error (MAPE)		12.9%
COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	na	11.6%
Mean Absolute Percentage Error (MAPE)	na	11.6%

Utility “I”

Figure 21

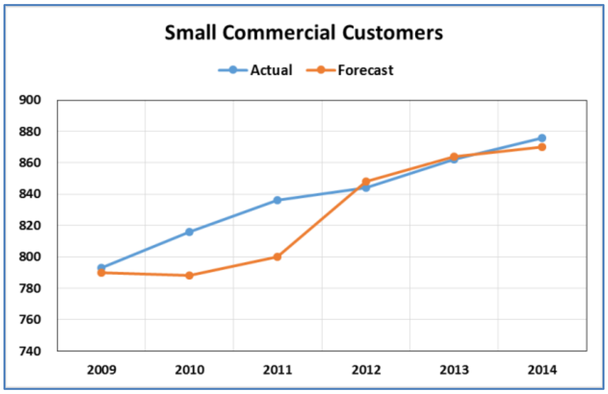


Figure 22

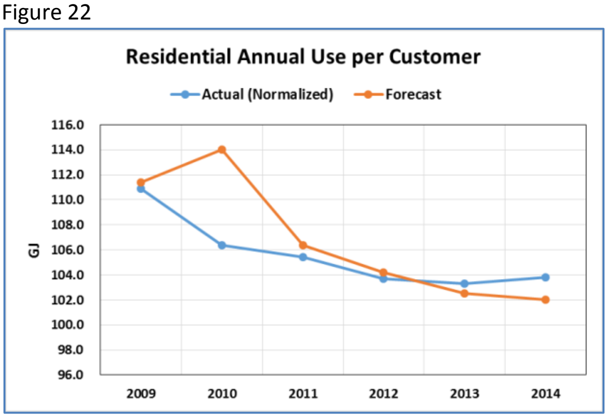


Figure 23

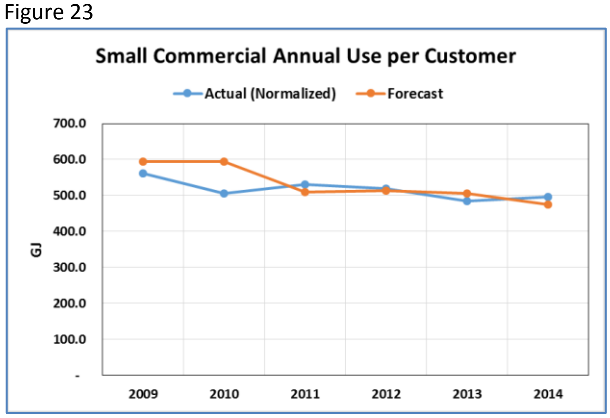


Table 9

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2014		
RESIDENTIAL FORECAST	**Customer**	**UPC**
Mean Percentage Error (MPE)		1.1%
Mean Absolute Percentage Error (MAPE)		1.9%
SMALL COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	-1.3%	3.0%
Mean Absolute Percentage Error (MAPE)	1.6%	6.1%

Utility “J”

Figure 24

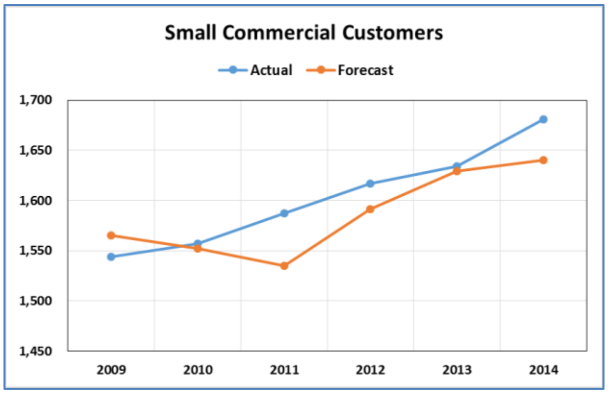


Figure 25

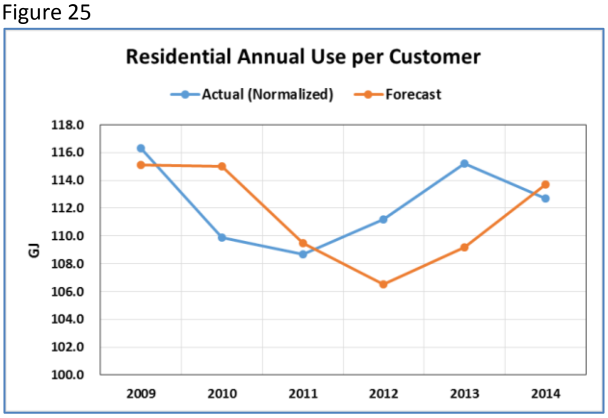


Figure 26

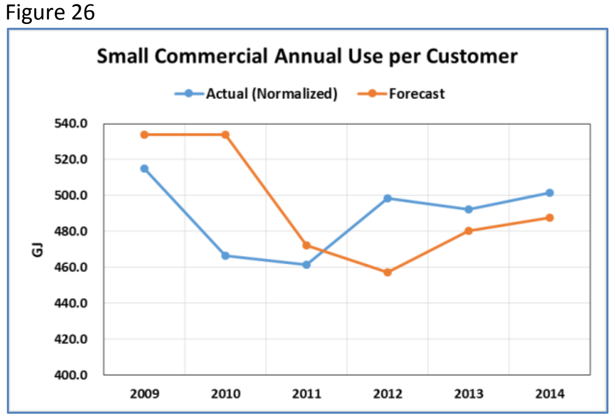


Table 10

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2014		
RESIDENTIAL FORECAST	**Customer**	**UPC**
Mean Percentage Error (MPE)		-0.7%
Mean Absolute Percentage Error (MAPE)		2.8%
SMALL COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	-1.1%	1.2%
Mean Absolute Percentage Error (MAPE)	1.6%	5.7%

Utility “K”

Figure 27

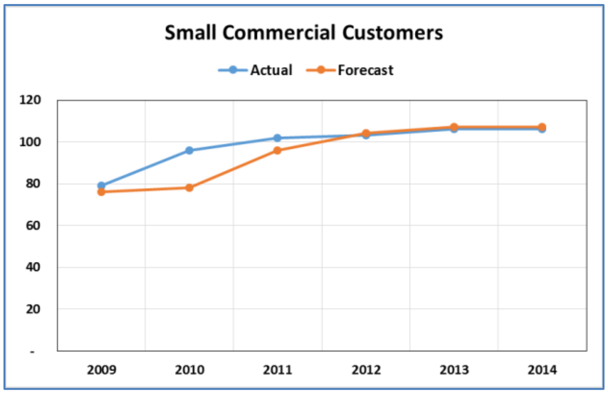


Figure 28

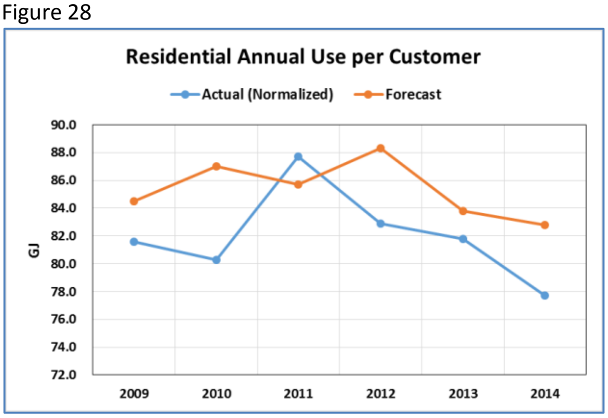


Figure 29

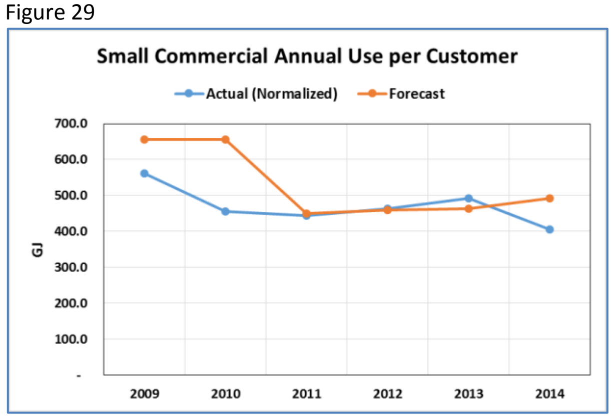


Table 11

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2014		
RESIDENTIAL FORECAST	**Customer**	**UPC**
Mean Percentage Error (MPE)		4.2%
Mean Absolute Percentage Error (MAPE)		5.0%
SMALL COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	-4.3%	12.9%
Mean Absolute Percentage Error (MAPE)	5.2%	15.1%

Utility "L"

Figure 30

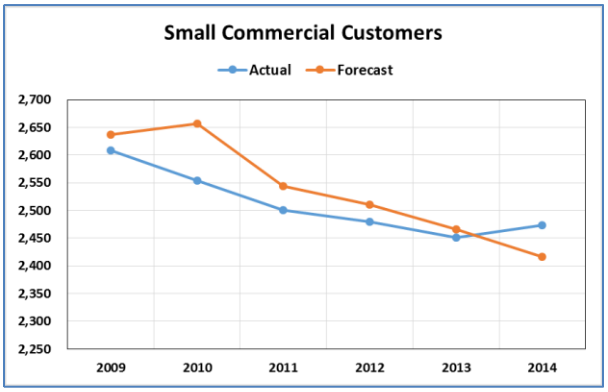


Figure 31

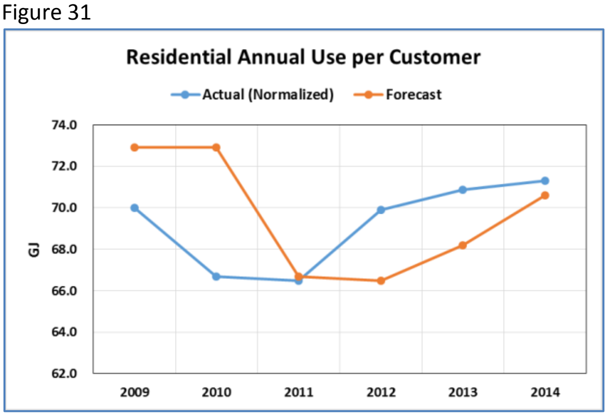


Figure 32

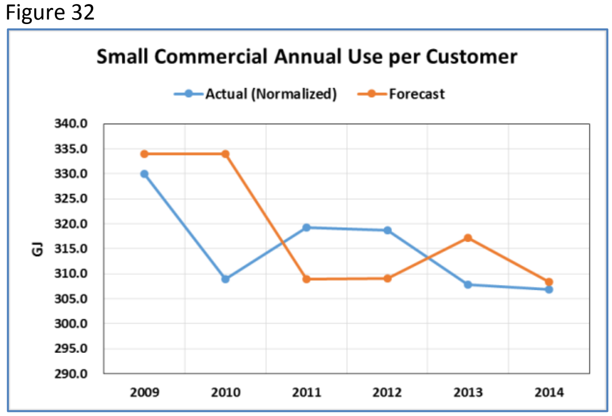


Table 12

SUMMARY STATISTICS FOR THE PERIOD 2009 - 2014		
RESIDENTIAL FORECAST	Customer	UPC
Mean Percentage Error (MPE)		0.7%
Mean Absolute Percentage Error (MAPE)		3.9%
SMALL COMMERCIAL FORECAST		
Mean Percentage Error (MPE)	1.1%	1.1%
Mean Absolute Percentage Error (MAPE)	1.8%	3.2%

Utility "M"

The following charts and table summarize the comparison of Utility "M"'s forecasts against normalized actual demand and customer counts. Small commercial customer growth has been even over the past four years and, consequently, an extrapolation of the linear trend into the forecast period has performed well, resulting in a MAPE of 0.7 percent. The small commercial demand has been consistently under-forecast by an average of 2.8 percent in each of the last three years. The absence of a predictable trend in large commercial customers and average demand challenges the creation of an accurate forecast.

Figure 33

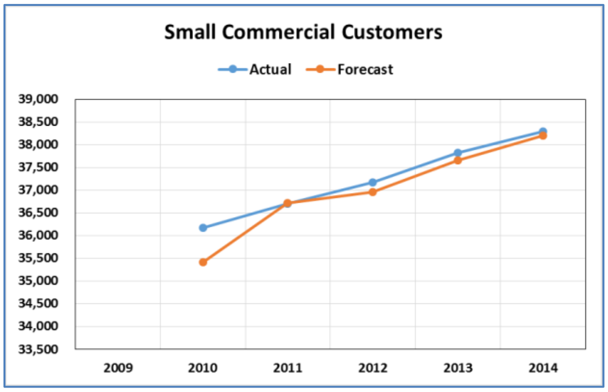


Figure 34

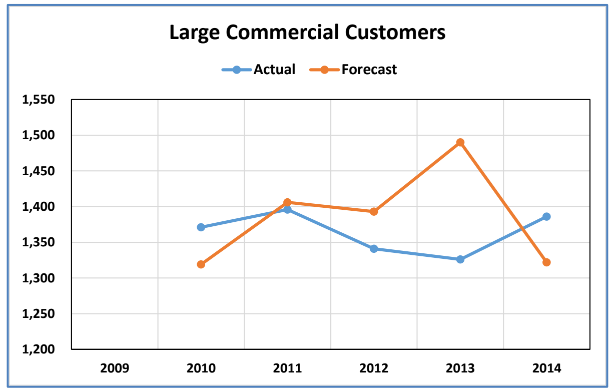


Figure 35

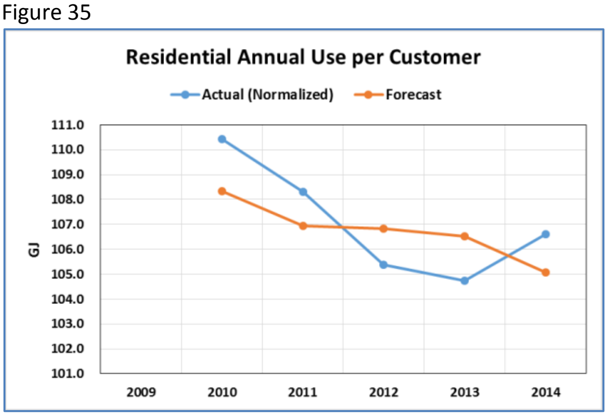


Figure 36

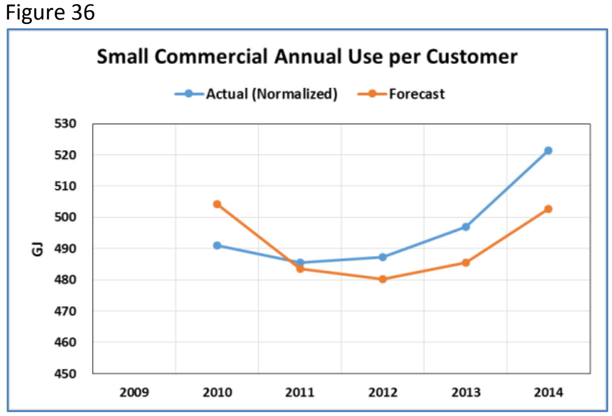


Figure 37

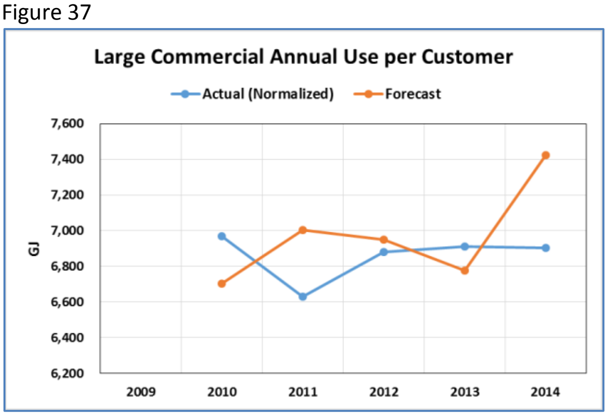


Figure 38

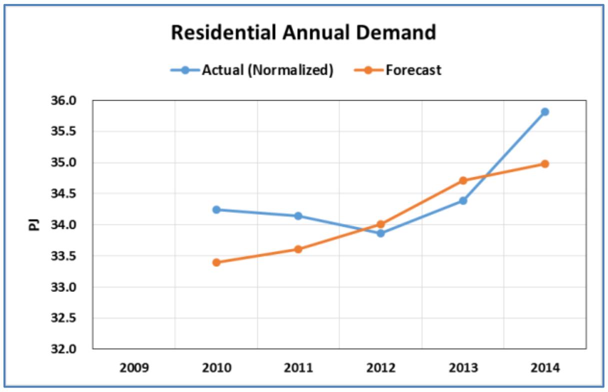


Figure 39

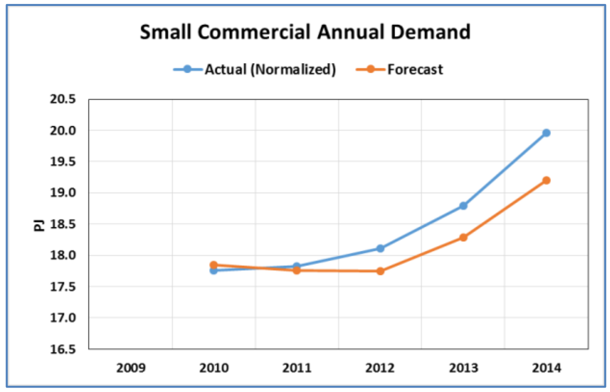


Figure 40

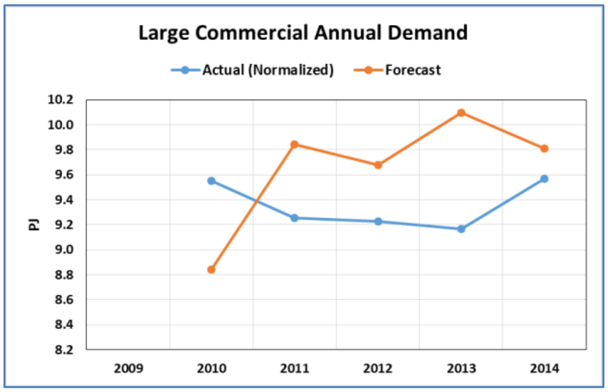


Table 13

SUMMARY STATISTICS FOR THE PERIOD 2010 - 2014			
RESIDENTIAL FORECAST	**Customer**	**UPC**	**Demand**
Mean Percentage Error (MPE)		-0.3%	-1.0%
Mean Absolute Percentage Error (MAPE)		1.5%	1.5%
SMALL COMMERCIAL FORECAST			
Mean Percentage Error (MPE)	-0.7%	-1.0%	-1.7%
Mean Absolute Percentage Error (MAPE)	0.7%	2.1%	1.9%
LARGE COMMERCIAL FORECAST			
Mean Percentage Error (MPE)	1.7%	1.7%	3.3%
Mean Absolute Percentage Error (MAPE)	5.1%	4.0%	6.3%

Utility “N”

Figure 41

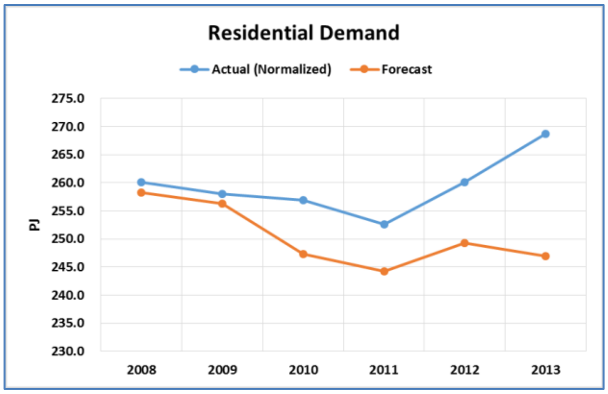


Table 14

SUMMARY STATISTICS FOR THE PERIOD 2008 - 2013		
RESIDENTIAL FORECAST	**Customer**	**Demand**
Mean Percentage Error (MPE)		-3.4%
Mean Absolute Percentage Error (MAPE)		3.4%

Utility “O”

The following charts and table summarize the comparison of Utility “O”’s forecasts against normalized actual demand and customer counts. Over the past six years Utility “O” has achieved a MAPE of 0.9 percent in its commercial customer forecast. Despite the strong first order linear trend exhibited by the residential UPC, the forecast only achieved a MAPE of 1.9 percent. The lack of a strong trend in commercial UPC over the period under study contributed to a MAPE of 3.9 percent.

Figure 42

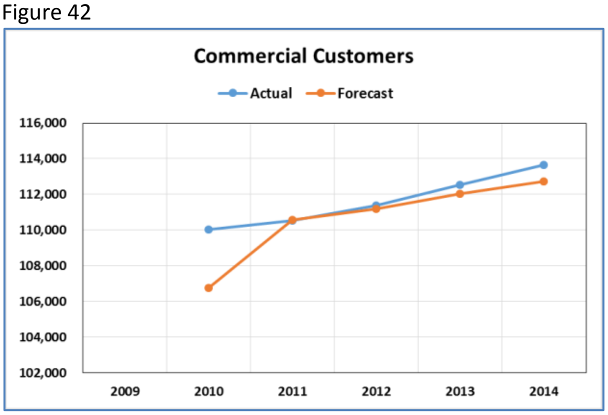


Figure 43

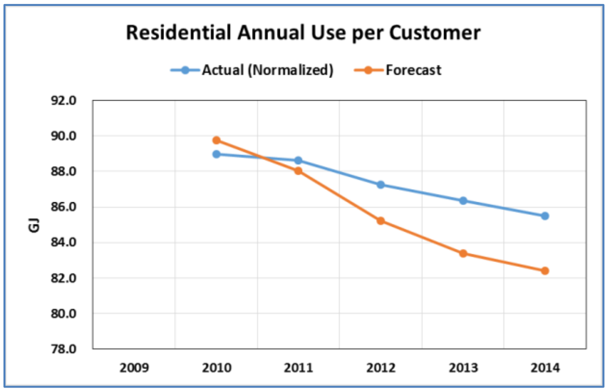


Figure 44

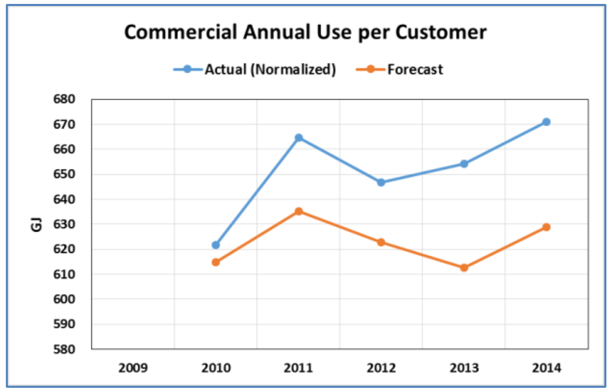


Figure 45

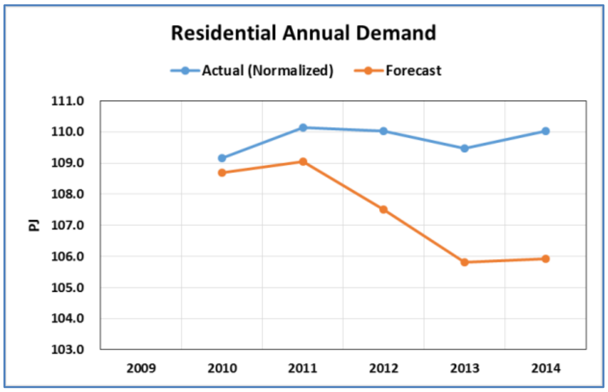


Figure 46

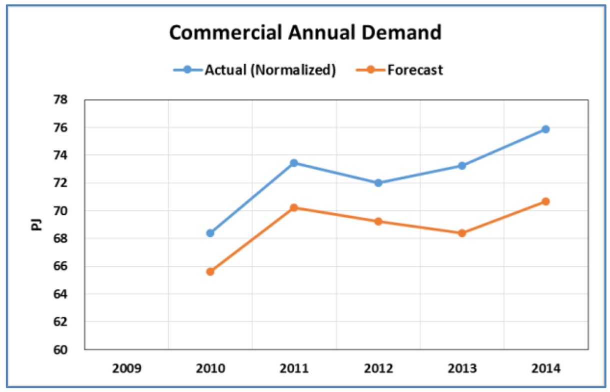


Table 15

SUMMARY STATISTICS FOR THE PERIOD 2010 - 2015			
RESIDENTIAL FORECAST	**Customer**	**UPC**	**Demand**
Mean Percentage Error (MPE)		-1.5%	-1.8%
Mean Absolute Percentage Error (MAPE)		1.9%	1.8%
COMMERCIAL FORECAST			
Mean Percentage Error (MPE)	-0.9%	-3.4%	-4.1%
Mean Absolute Percentage Error (MAPE)	0.9%	3.9%	4.5%

APPENDIX C: UTILITY DATA

Utility "A"

Commercial	Customer Billings			
	Actual	Forecast	MPE	MAPE
2009				
2010	79,287			
2011	80,235	80,041	-0.2%	0.2%
2012	81,907	81,491	-0.5%	0.5%
2013	83,522	83,325	-0.2%	0.2%
2014	85,063	84,717	-0.4%	0.4%
2011 - 2014			**-0.3%**	**0.3%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	119.8			
2010	118.8			
2011	121.3			
2012	117.9	114.6	-2.8%	2.8%
2013	119.7	117.8	-1.6%	1.6%
2014	120.4	117.2	-2.7%	2.7%
2012 - 2014			**-2.3%**	**2.3%**

Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	669.1			
2010	688.8			
2011	678.0			
2012	731.4	704.9	-3.6%	3.6%
2013	753.6	732.8	-2.8%	2.8%
2014	724.4	755.4	4.3%	4.3%
2012 - 2014			**-0.7%**	**3.6%**

Utility "B"

Residential	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	11.40	10.63	-6.8%	6.8%
2010	10.92	10.49	-3.9%	3.9%
2011	11.41	11.01	-3.5%	3.5%
2012	7.89	11.05	40.0%	40.0%
2013		11.04		
2014				
2015				
2009 - 2012			**6.4%**	**13.5%**

Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	5.93	6.16	3.9%	3.9%
2010	6.64	6.21	-6.6%	6.6%
2011	6.73	6.76	0.4%	0.4%
2012	6.62	6.79	2.6%	2.6%
2013		6.44		
2014				
2015				
2009 - 2012			**0.1%**	**3.4%**

Utility "C"

Small Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2008/09	16,698			
2009/10	16,732			
2010/11	16,743	16,786	0.3%	0.3%
2011/12	16,817	16,899	0.5%	0.5%
2012/13	16,833	16,947	0.7%	0.7%
2013/14	16,936	17,137	1.2%	1.2%
2011 - 2014			**0.7%**	**0.7%**

Large Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2008/09	7,789			
2009/10	7,822			
2010/11	7,847	7,857	0.1%	0.1%
2011/12	7,895	7,806	-1.1%	1.1%
2012/13	7,929	7,844	-1.1%	1.1%
2013/14	8,011	7,736	-3.4%	3.4%
2011 - 2014			**-1.4%**	**1.4%**

Residential	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2008/09				
2009/10	22.66	22.59	-0.3%	0.3%
2010/11		22.72		
2011/12	22.49	22.37	-0.5%	0.5%
2010 - 2012			**-0.4%**	**0.4%**

Small Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2008/09				
2009/10	3.53	3.44	-2.6%	2.6%
2010/11		3.49		
2011/12	3.63	3.57	-1.8%	1.8%
2010 - 2012			**-2.2%**	**2.2%**

Large Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2008/09				
2009/10	19.00	18.71	-1.5%	1.5%
2010/11		19.20		
2011/12	19.32	18.95	-1.9%	1.9%
2010 - 2012			**-1.7%**	**1.7%**

Total Demand*	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2007/08	60.08	61.21	1.9%	1.9%
2008/09	59.93	60.88	1.6%	1.6%
2009/10	59.48	60.64	2.0%	2.0%
2010/11	59.48	61.15	2.8%	2.8%
2011/12	60.52	60.57	0.1%	0.1%
2008 - 2012			**1.7%**	**1.7%**

* Excluding Special Contract and Power Generation demand

Utility "D"

General Service & Contract	Customers			
	Actual	Forecast	MPE	MAPE
2009	1,887,605	1,906,437	1.0%	1.0%
2010	1,926,294	1,931,528	0.3%	0.3%
2011	1,960,378	1,965,538	0.3%	0.3%
2012	1,994,903	1,984,734	-0.5%	0.5%
2013	2,030,001	2,025,462	-0.2%	0.2%
2014	2,063,837	2,059,619	-0.2%	0.2%
2009 - 2014			**0.1%**	**0.4%**

Residential	Use per Customer(GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	98.4	99.7	1.3%	1.3%
2010	97.5	99.1	1.7%	1.7%
2011	98.1	99.9	1.9%	1.9%
2012	95.6	94.9	-0.8%	0.8%
2013	96.3	97.1	0.8%	0.8%
2014	93.6	92.0	-1.7%	1.7%
2009 - 2014			**0.5%**	**1.3%**

Small Commercial	Use per Customer(GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	1,031	1,065	3.2%	3.2%
2010	1,100	1,056	-4.0%	4.0%
2011	1,114	1,059	-4.9%	4.9%
2012	1,094	1,139	4.1%	4.1%
2013	1,104	1,129	2.3%	2.3%
2014	1,082	1,073	-0.9%	0.9%
2009 - 2014			**0.0%**	**3.2%**

Utility "E"

System Firm Demand	Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	153.9	166.3	8.1%	8.1%
2010	157.5	151.3	-3.9%	3.9%
2011	159.1	153.4	-3.6%	3.6%
2012	162.3	153.1	-5.7%	5.7%
2013	176.7	175.9	-0.4%	0.4%
2009 - 2013			**-1.1%**	**4.3%**

Utility "F"

All Sales Customers	Customers			
	Actual	Forecast	MPE	MAPE
2009-10	1,216,844	1,207,161	-0.8%	0.8%
2010-11	1,212,623	1,186,060	-2.2%	2.2%
2011-12	1,213,521	1,164,124	-4.1%	4.1%
2012-13	1,219,246	1,205,427	-1.1%	1.1%
2013-14	1,224,856	1,220,845	-0.3%	0.3%
2014-15		1,228,953		
2010 - 2014			**-1.7%**	**1.7%**

All Sales Customers	Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009-10	165.1	172.0	4.2%	4.2%
2010-11	163.8	161.6	-1.3%	1.3%
2011-12	164.8	167.0	1.3%	1.3%
2012-13	165.8	164.8	-0.6%	0.6%
2013-14	168.6	162.0	-3.9%	3.9%
2014-15				
2010 - 2014			**-0.1%**	**2.3%**

Utility "G"

Residential Demand	Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	212.9	223.5	5.0%	5.0%
2010	214.5	218.8	2.0%	2.0%
2011	221.8	218.4	-1.5%	1.5%
2012	208.9	215.3	3.1%	3.1%
2013	213.6	214.1	0.2%	0.2%
2014	173.9	212.1	22.0%	22.0%
2015				
2009 - 2014			**5.1%**	**5.6%**

Utility “H”

Residential	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	40.32	42.78	6.1%	6.1%
2010	37.78	42.53	12.6%	12.6%
2011	40.69	42.69	4.9%	4.9%
2012	32.18	42.24	31.3%	31.3%
2013	38.27	41.99	9.7%	9.7%
2014		38.37		
2009 - 2013			**12.9%**	**12.9%**

Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	10.41	11.37	9.2%	9.2%
2010	9.55	11.10	16.2%	16.2%
2011	10.08	10.45	3.6%	3.6%
2012	8.32	9.99	20.1%	20.1%
2013	9.11	9.92	8.8%	8.8%
2014		9.50		
2009 - 2013			**11.6%**	**11.6%**

Utility “I”

Small Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009	793	790	-0.4%	0.4%
2010	816	788	-3.4%	3.4%
2011	836	800	-4.3%	4.3%
2012	844	848	0.5%	0.5%
2013	862	864	0.2%	0.2%
2014	876	870	-0.7%	0.7%
2009 - 2014			**-1.3%**	**1.6%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	110.9	111.4	0.5%	0.5%
2010	106.4	114.0	7.1%	7.1%
2011	105.4	106.4	0.9%	0.9%
2012	103.7	104.2	0.5%	0.5%
2013	103.3	102.5	-0.8%	0.8%
2014	103.8	102.0	-1.7%	1.7%
2009 - 2014			**1.1%**	**1.9%**

Small Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	560.7	593	5.8%	5.8%
2010	505.3	593	17.4%	17.4%
2011	531.4	510	-4.0%	4.0%
2012	518.5	514	-0.9%	0.9%
2013	484.9	505	4.0%	4.0%
2014	496.2	475	-4.2%	4.2%
2009 - 2014			**3.0%**	**6.1%**

Utility “J”

Small Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009	1,544	1,565	1.4%	1.4%
2010	1,557	1,552	-0.3%	0.3%
2011	1,587	1,535	-3.3%	3.3%
2012	1,617	1,591	-1.6%	1.6%
2013	1,634	1,629	-0.3%	0.3%
2014	1,681	1,640	-2.4%	2.4%
2009 - 2014			**-1.1%**	**1.6%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	116.3	115.1	-1.0%	1.0%
2010	109.9	115.0	4.6%	4.6%
2011	108.7	109.5	0.7%	0.7%
2012	111.2	106.5	-4.2%	4.2%
2013	115.2	109.2	-5.2%	5.2%
2014	112.7	113.7	0.9%	0.9%
2009 - 2014			**-0.7%**	**2.8%**

Small Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	514.9	534	3.7%	3.7%
2010	466.5	534	14.4%	14.4%
2011	461.2	472	2.3%	2.3%
2012	498.3	457	-8.3%	8.3%
2013	492.1	480	-2.4%	2.4%
2014	501.3	488	-2.8%	2.8%
2009 - 2014			**1.2%**	**5.7%**

Utility "K"

Small Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009	79	76	-3.8%	3.8%
2010	96	78	-18.8%	18.8%
2011	102	96	-5.9%	5.9%
2012	103	104	1.0%	1.0%
2013	106	107	0.9%	0.9%
2014	106	107	0.9%	0.9%
2009 - 2014			**-4.3%**	**5.2%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	81.6	84.5	3.6%	3.6%
2010	80.3	87.0	8.3%	8.3%
2011	87.7	85.7	-2.3%	2.3%
2012	82.9	88.3	6.5%	6.5%
2013	81.8	83.8	2.4%	2.4%
2014	77.7	82.8	6.6%	6.6%
2009 - 2014			**4.2%**	**5.0%**

Small Commercial	Use per Account (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	562.2	657	16.8%	16.8%
2010	456.2	657	43.9%	43.9%
2011	443.5	450	1.5%	1.5%
2012	463.9	460	-0.8%	0.8%
2013	491.0	463	-5.7%	5.7%
2014	404.4	493	21.9%	21.9%
2009 - 2014			**12.9%**	**15.1%**

Utility "L"

Small Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009	2,608	2,637	1.1%	1.1%
2010	2,554	2,657	4.0%	4.0%
2011	2,500	2,544	1.8%	1.8%
2012	2,480	2,510	1.2%	1.2%
2013	2,451	2,466	0.6%	0.6%
2014	2,473	2,417	-2.3%	2.3%
2009 - 2014			**1.1%**	**1.8%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	70.0	72.9	4.1%	4.1%
2010	66.7	72.9	9.3%	9.3%
2011	66.5	66.7	0.3%	0.3%
2012	69.9	66.5	-4.9%	4.9%
2013	70.9	68.2	-3.8%	3.8%
2014	71.3	70.6	-1.0%	1.0%
2009 - 2014			**0.7%**	**3.9%**

Small Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009	329.9	334	1.2%	1.2%
2010	308.9	334	8.1%	8.1%
2011	319.2	309	-3.2%	3.2%
2012	318.6	309	-3.0%	3.0%
2013	307.8	317	3.0%	3.0%
2014	306.9	308	0.5%	0.5%
2009 - 2014			**1.1%**	**3.2%**

Utility “M”

Small Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009				
2010	36,172	35,408	-2.1%	2.1%
2011	36,701	36,714	0.0%	0.0%
2012	37,164	36,953	-0.6%	0.6%
2013	37,814	37,658	-0.4%	0.4%
2014	38,286	38,194	-0.2%	0.2%
2010 - 2014			**-0.7%**	**0.7%**

Large Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009				
2010	1,371	1,319	-3.8%	3.8%
2011	1,396	1,406	0.7%	0.7%
2012	1,341	1,393	3.9%	3.9%
2013	1,326	1,490	12.4%	12.4%
2014	1,386	1,322	-4.6%	4.6%
2010 - 2014			**1.7%**	**5.1%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	110.4	108.3	-1.9%	1.9%
2011	108.3	107.0	-1.3%	1.3%
2012	105.4	106.8	1.4%	1.4%
2013	104.7	106.5	1.7%	1.7%
2014	106.6	105.1	-1.4%	1.4%
2010 - 2014			**-0.3%**	**1.5%**

Small Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	491	504	2.7%	2.7%
2011	486	484	-0.4%	0.4%
2012	487	480	-1.4%	1.4%
2013	497	486	-2.3%	2.3%
2014	521	503	-3.6%	3.6%
2010 - 2014			**-1.0%**	**2.1%**

Large Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	6,967	6,702	-3.8%	3.8%
2011	6,628	7,003	5.7%	5.7%
2012	6,882	6,950	1.0%	1.0%
2013	6,912	6,777	-2.0%	2.0%
2014	6,905	7,423	7.5%	7.5%
2010 - 2014			**1.7%**	**4.0%**

Residential	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	34.2	33.4	-2.5%	2.5%
2011	34.1	33.6	-1.6%	1.6%
2012	33.9	34.0	0.4%	0.4%
2013	34.4	34.7	0.9%	0.9%
2014	35.8	35.0	-2.3%	2.3%
2010 - 2014			**-1.0%**	**1.5%**

Small Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	17.8	17.9	0.5%	0.5%
2011	17.8	17.8	-0.4%	0.4%
2012	18.1	17.7	-2.0%	2.0%
2013	18.8	18.3	-2.7%	2.7%
2014	20.0	19.2	-3.8%	3.8%
2010 - 2014			**-1.7%**	**1.9%**

Large Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	9.6	8.8	-7.5%	7.5%
2011	9.3	9.8	6.4%	6.4%
2012	9.2	9.7	4.9%	4.9%
2013	9.2	10.1	10.2%	10.2%
2014	9.6	9.8	2.5%	2.5%
2010 - 2014			**3.3%**	**6.3%**

Utility “N”

Residential Demand	Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2008	260.1	258.2	-0.7%	0.7%
2009	258.0	256.3	-0.6%	0.6%
2010	256.9	247.3	-3.7%	3.7%
2011	252.6	244.2	-3.3%	3.3%
2012	260.1	249.3	-4.2%	4.2%
2013	268.7	246.9	-8.1%	8.1%
2014		264.1		
2008 - 2013			**-3.4%**	**3.4%**

Utility "O"

Commercial	Customers			
	Actual	Forecast	MPE	MAPE
2009				
2010	110,029	106,753	-3.0%	3.0%
2011	110,527	110,555	0.0%	0.0%
2012	111,383	111,196	-0.2%	0.2%
2013	112,540	112,032	-0.5%	0.5%
2014	113,667	112,732	-0.8%	0.8%
2015	114,238	114,085		
2010 - 2015			**-0.9%**	**0.9%**

Residential	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	89.0	89.8	0.9%	0.9%
2011	88.6	88.0	-0.7%	0.7%
2012	87.3	85.2	-2.3%	2.3%
2013	86.3	83.4	-3.4%	3.4%
2014	85.5	82.4	-3.6%	3.6%
2015	83.6	83.9	0.3%	0.3%
2010 - 2015			**-1.5%**	**1.9%**

Commercial	Use per Customer (GJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	621.8	614.8	-1.1%	1.1%
2011	664.5	635.2	-4.4%	4.4%
2012	646.6	622.7	-3.7%	3.7%
2013	654.2	612.5	-6.4%	6.4%
2014	671.0	628.7	-6.3%	6.3%
2015	651.5	660.9	1.4%	1.4%
2010 - 2015			**-3.4%**	**3.9%**

Residential	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	109.2	108.7	-0.4%	0.4%
2011	110.1	109.0	-1.0%	1.0%
2012	110.0	107.5	-2.3%	2.3%
2013	109.5	105.8	-3.3%	3.3%
2014	110.0	105.9	-3.7%	3.7%
2015	109.2	109.3	0.1%	0.1%
2010 - 2015			**-1.8%**	**1.8%**

Commercial	Annual Demand (PJ)			
	Actual (Normalized)	Forecast	MPE	MAPE
2009				
2010	68.4	65.6	-4.1%	4.1%
2011	73.4	70.2	-4.4%	4.4%
2012	72.0	69.2	-3.9%	3.9%
2013	73.2	68.4	-6.6%	6.6%
2014	75.9	70.7	-6.8%	6.8%
2015	74.3	75.2	1.2%	1.2%
2010 - 2015			**-4.1%**	**4.5%**

Appendix A4-C

CBOC ECONOMETRIC FORECASTS

Variable	Definition
Housing Starts (Number Of Units)	The number of residential units for which construction has begun.
GDP @ Mkt prices (2007$)	The gross value at market prices of all goods and services produced by the economy, plus taxes but minus subsidies on imports.
BC CPI	The CPI provides a broad measure of the cost of living in Canada. Statistics Canada produces the CPI by tracking the prices for some 600 of the most commonly bought goods and services.
Wages and Salaries/ Employee	Includes the values of any social contributions, income taxes, etc., payable by the employee even if they are actually withheld by the employer for administrative convenience or other reasons and paid directly to social insurance schemes, tax authorities, etc., on behalf of the employee. Wages and salaries may be paid in various ways, including goods or services provided to employees for remuneration in kind instead of, or in addition to, remuneration in cash.
Primary Household Income	Incomes that accrue to households as a consequence of their involvement in processes of production or ownership of assets that may be needed for purposes of production.
Household Disposable Income	The sum of all incomes received by households. Factor earnings include compensation of employees, net mixed income, and net property income. Examples of net property income include interest income received less interest income paid, royalties received on natural resources, dividends received less dividends paid.
CBOC Labour Force	The non-institutionalized population aged 15 and over, excluding those who are unwilling or unable to work.
Employment	Employed persons are those who, during the reference week: a. did any work at all at a job or business, that is, paid work in the context of an employer-employee relationship, or self-employment. It also includes unpaid family work, which is defined as unpaid work contributing directly to the operation of a farm, business or professional practice owned and operated by a related member of the same household; or b. had a job but were not at work due to factors such as own illness or disability, personal or family responsibilities, vacation, labour dispute or other reasons (excluding persons on layoff, between casual jobs, and those with a job to start at a future date).
Unemployment Rate %	Proportion of the active labour force aged 15 or older who do not have a job.
Retail Sales	Retail sales are an aggregated measure of the sales of retail goods over a stated time period.
Participation rate	The percentage of the population 15 years of age and older that is in the labour force.

Appendix B

Natural Gas for Transportation and LNG Service

Table of Contents

1. INTRODUCTION

FEI has made significant progress in adding natural gas demand to the distribution system through increased adoption of natural gas vehicles. This increased adoption has resulted in FEI contracting with natural gas for transportation (NGT) customers for compressed natural gas (CNG) and liquefied natural gas (LNG) fueling station services. FEI expects to continue to add natural gas demand to the distribution system by advancing both CNG and LNG transportation applications. To advance this demand, FEI issues incentives under the Greenhouse Gas Reduction (Clean Energy Act) Regulation (GGRR) for new market segments as well as to support continued growth in currently captured market segments. The GGRR is also expected to lead to an increased demand for CNG and LNG fueling stations as the requirement for fueling infrastructure continues to expand over the next number of years.

This appendix provides details on FEI's 2017 revenue and cost forecasts for the NGT program and transportation aspects of LNG service. The NGT program consists of the construction and maintenance of the CNG or LNG fueling stations and the incentives to convert eligible vehicles from diesel and gasoline to CNG or LNG. The related LNG service includes tanker transportation service available to LNG customers as well as capital expenditures at the Tilbury LNG facility to support the growth of LNG demand. LNG volumes reported herein also include non-NGT activities, which are primarily power generation applications.

The following table provides a brief summary of how each component of the NGT program relates to the 2017 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]
Demand and Revenue Forecast	The demand associated with CNG & LNG NGT and non-NGT customers is embedded in Rate Schedule 25 and Rate Schedule 46 and as such, included in the overall utility revenue and delivery margin forecast for 2017 as set out in Section 3 of the Application.	The 2017 demand and revenue forecast for CNG and LNG is based on (i) existing demand and (ii) incremental demand for 2017 determined by utilizing the forecast vehicle conversion incentives and fueling station additions as the primary inputs, as well as the addition of non-NGT demand that FEI expects to serve under Rate Schedule 46.

[1] The term 'Vehicle' is defined to include on-road trucks, buses, waste haulers, mine haul trucks and marine vessels.
[2] The setting of rates to recover the costs of prescribed undertakings is required under section 28 of the *Clean Energy Act*.

Program Component	Connection to Revenue Requirement	Background
Fueling Stations	Expenditures associated with fueling stations are included in the 2017 capital and O&M forecasts (Sections 6 and 7 of the Application). The forecast capital and O&M of fueling station services included in the delivery cost of service is offset by the revenue recovered from 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 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 under the GGRR, FEI will apply for a CPCN for the construction and operation of that fueling station. For 2017, 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, even a service that qualifies as a prescribed undertaking requires an application to and approval by the Commission.
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.
Tilbury LNG Expansion[3]	Expenditures associated with the expansion of the Tilbury LNG facility are included in the 2016 capital expenditure forecast and included in rate base as of January 1, 2017.	The capital expenditures and cost recovery for the project were approved in Order In Council No. 557 and 749 for the Tilbury LNG expansion.

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.

[3] 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.

- Section 3- Vehicle Incentives: provides a forecast of the incentives that will be provided in 2017.

- Section 4- CNG & LNG Demand and Revenue: provides a forecast of natural gas demand for NGT and non-NGT power generation and a discussion of the corresponding revenue and margin forecasts for 2017.

- 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 2017.

- Section 6- Enabling LNG Demand Fulfilment: discusses the forecast costs and recoveries associated with the tanker transportation service as well as the forecast costs associated with the Tilbury Expansion Project.

- 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 2017 forecast revenue requirement.

The organization of Sections 3 through 6 follows the business model for NGT. FEI provides incentives to customers for the purchase of CNG/LNG powered vehicles or the conversion of eligible vehicles such as ferries, locomotives or minehaul trucks (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 station 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 (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 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.[4] 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.

[4] 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.[5] 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 amended again 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"[6];
- providing an alternative for fueling station service agreements; and
- adding a prescribed undertaking that provides incentives for the conversion of a "specified vehicle"[7] 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.

The rates related to each new fueling station service agreement constructed under the GGRR will be submitted in separate applications to the British Columbia Utilities Commission (BCUC) for review and approval.

2.3 LNG AND CNG SUPPLY

FEI is supplying LNG under Rate Schedule 46 to customers on both a firm (short and long term contract) and spot basis.

For CNG services, FEI has four Commission-approved CNG natural gas vehicle Tariffs:

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5 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.

6 "Early adopter vehicle" as defined in the GGRR, Section 2 Prescribed Undertakings.

7 A "specified vehicle" means a heavy-duty vehicle, medium-duty vehicle, school bus or transit bus, as defined in the GGRR, Section 1.

1. Rate Schedule 6 Natural Gas Vehicle Service sets terms and conditions for companies that retail natural gas to their customers with natural gas vehicles or fleet customers that use natural gas for their own fleet;
2. Rate Schedule 6A General Service Vehicle Refueling Service, which is for NGT use only, to provide on-site CNG vehicle refuelling and compression services and is applicable in the Lower Mainland service area only;
3. Rate Schedule 6P Public Service, which is a CNG fuelling service available to the general public at the FEI Surrey Operations Centre (16705 Fraser Highway, Surrey, BC); and
4. Rate Schedule 26 Natural Gas Vehicle Transportation Service, which sets terms and conditions for service to customers with consumption of greater than 2,000 gigajoules (GJ) annually for the sole purpose of using the gas to fuel vehicles.

In addition to FEI providing natural gas supply under Commission approved FEI Rate Schedules, natural gas compression and fueling services are available to customers with natural gas fueled vehicles who have entered into an agreement with FEI for FEI to own and operate fueling stations and to provide CNG or LNG fueling services. As mentioned in Section 2.2 above, these agreements are approved by the Commission.

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 or for related safety practices and maintenance facility upgrades up to $62.0 million in total (Prescribed Undertaking 1).

Applications are accepted every quarter and the fairness advisor ensures that the evaluation process and the provision of funds are conducted in an objective and fair manner. The fairness advisor is an independent consultant that reviews and provides comments on the program and the process 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 forecast of GGRR incentives under Prescribed Undertaking 1 to be paid out in 2016 and 2017 by category. This table reflects the forecast incentives that will be paid out and added to the NGT Incentives Deferral Account as approved by Order G-161-12. The balance in this deferral account has been approved by the same order to be recovered in the delivery rates of non-bypass customers over a period of ten years.

Table B-2: FEI Forecast GGRR (NGT) Incentive Deferral Additions ($millions)[8]

Incentive Forecast		2016A		2016P		2017F
Total Vehicle Incentives	$	2.400	$	3.300	$	4.000
Marine, Mining & Rail Incentives	$	2.300	$	2.065	$	8.250
Safety Practices and Maintenance Facilities Incentives	$	-	$	1.000	$	0.500
Admin, Education, Safety Training	$	0.798	$	0.798	$	0.798
Total	$	5.498	$	7.163	$	13.548

Typically there is a lag of up to two years between the time an applicant applies for an incentive and when the vehicles are in service. For this reason FEI has a two-step process for providing incentives. A small amount (up to 25%) is paid at the time of approving the application for incentives and the remaining amount is paid to the customer once the vehicles are in service.

For the 2016 year end projection, FEI anticipates issuing $5.365 million in vehicle, marine and mining incentives. In addition, $0.798 million related to administration, safety and training expenditures, and $1.000 million related to safety practices and maintenance. Facility upgrade incentives are also projected for 2016, for a total of $7.163 million (for all committed applicants[9] from the 2014 and 2015 incentive rounds). Of the total $7.163 million, $3.300 million consists of incentives for CNG vehicles that have entered service in 2016 and incentives for a portion of the CNG vehicles expected to be in service in early 2017. Of the $3.3 million, $300,000 is allocated

8 Throughout the tables in this appendix, “A” refers to Approved for 2016, (Order G-193-15 in relation to the FEI Annual Review for 2016 Application), “P” refers to Projected for 2016, and “F” refers to Forecast for 2017.

9 Committed applicant refers to an applicant that has applied to the FEI incentive program and made a firm purchase commitment to buy natural gas vehicles/vessels/mine haul trucks.

for applicants interested in the LNG diesel blending pilot application (Prescribed Undertaking 3.1) as authorized by OIC No. 297. This pilot was introduced to address the gap that existed in the availability of 15L Original Equipment Manufacturer (OEM) engines. Of the $2.065 million for marine, mining and rail incentives, $1.75 million is allocated for advancing 25% of the agreed incentive contribution amount of $7 million for the two incremental marine vessels subject to BC Ferries procuring LNG from FEI and $0.315 million is for the remaining 75% payment for 6 mine haul trucks. In addition, there is $0.798 million related to administration, education and training expenses. For 2016 and 2017, there is $1.000 million and $0.500 million respectively, for safety practices and upgrading maintenance facilities grants. Grants to persons in British Columbia to implement safety practices and to upgrade maintenance facilities are now shown as a separate line item in Table B-2. (Prescribed Undertaking 1[10]), and these incentives were not projected in the FEI Annual Review for 2016 Rates Application (the 2016 Annual Review).

For 2017, FEI forecasts that a total of $13.548 million including incentives for eligible vehicle purchases, and for implementation of safety practices and improvement of facilities for operating vehicles, and expenditures for administration, education and training. For the vehicle purchases, most of the incentives are for the remaining 75% of commitments made in the 2015 round (and a smaller portion is related to the expected commitments from the 2016 round) for CNG applicants and the LNG diesel blending pilot application (Prescribed Undertaking 3.1), authorized by OIC No. 297. Most of the $8.250 million for the marine, mine and rail category is for the remaining 75% of the 5 marine vessels that were committed in the 2013 and 2014 incentive rounds.

The provision of incentives has a direct impact on the NGT demand and revenue forecast discussed further in Section 4 of this appendix below and, correspondingly, the forecast of fueling station additions discussed in Section 5 of this appendix below.

[10] GGRR Prescribed Undertaking 1 (a) (i) (ii) (A) to implement safety practices, (B) to improve maintenance facilities.

4. CNG & LNG DEMAND AND REVENUE

4.1 FORECAST NGT & NON-NGT DEMAND

Table B-3 below provides a forecast of total NGT and non-NGT demand in 2016 and 2017 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 customers.[11] As directed in Order G-86-15, FEI has now included a forecast of spot purchases in the total NGT and non-NGT demand.

Table B-3: FEI Total Natural Gas Demand (GJ/Year) for NGT & Non-NGT

GJ	2016A	2016P	2017F
CNG	586,224	659,336	769,467
LNG	561,824	520,525	2,136,388
Total NGT Demand	**1,148,049**	**1,179,862**	**2,905,855**
Non-NGT CNG/LNG Demand	106,904	146,507	165,866
Total NGT and Non-NGT Demand	**1,254,953**	**1,326,369**	**3,071,721**

The total forecasted natural gas demand for 2017 of 3,071,721 GJ includes forecasted spot volumes of 999,348 GJ. The spot volumes consist of 165,866 GJ related to non-NGT customers mostly for power generation, and 833,482 GJ in new NGT demand mainly related to marine vessels. Since FEI does not have a stable historical level of spot volumes on which to establish a demand forecast, FEI has primarily relied on specific customer information for its forecast. For the spot volumes related to the power generation customers, FEI contacted the customers directly and received information on how much LNG would be required.

The incremental increase in NGT and non-NGT demand between 2016 and 2017 is 1,745,353 GJ. The following table provides a list of the number of vehicles and the demand that makes up this incremental load.

[11] Spot Volumes for Cryopeak, NWT Energy Corp, Yukon Energy and Anahim Lake are non-NGT and are mainly for the purposes of power generation.

Table B-4: CNG/LNG 2017 Demand Additions[12]

Customer Fuel	No. of NG Vehicles	Vehicle In-Service Date	2017 Incremental Demand (GJ)
CNG	8	January 1, 2017	12,000
CNG	2	January 1, 2017	1,121
CNG	22	September 1, 2016	25,000
CNG	n/a [13]	n/a	700
CNG	n/a [14]	n/a	4,845
CNG	0	3rd Party Station Vol.	30,000
CNG	0	3rd Party Station Vol.	200
CNG	0	3rd Party Station Vol.	3,000
CNG	47	April 1, 2017	20,625
CNG	20	July 1, 2016	3,000
CNG	3	July 1, 2016	2,500
CNG	5	August 1, 2016	6,417
CNG	2	August 1, 2016	723
LNG	n/a [13]	n/a	3,087
LNG	n/a [13]	n/a	2,088
LNG	7	July 1, 2017	65,000
LNG	2	November 1, 2016	155,000
LNG	3	December 1, 2016	200,000
LNG	1	May 1, 2017	1,190,688
LNG	0	Non-NGT	900
LNG	0	Non-NGT	3,459
LNG	0	Non-NGT	15,000
Total	**122**		**1,745,353**

The incremental demand of 1,745,353 GJ will be in addition to the 1,326,369 GJ of forecast annual demand from existing NGT and non-NGT customers to the end of 2016.

A total of 1,190,688 GJ in incremental LNG demand in 2017 reflects the new demand attributable to two agreements[15] between FEI and Puget Sound Energy (PSE) under Rate Schedule 46. Under both agreements, FEI will provide LNG to one shipping vessel that will be operated by Totem Ocean Trailer (TOTE) in the Port of Tacoma, collectively known as

[12] Pursuant to Order G105-15, the names of customers have been removed to preserve confidentiality.
[13] Incremental Demand forecast for 2017 is the result of an increase in forecasted consumption for 2017 above the Minimum Take or Pay as per the applicable agreement.
[14] Incremental Demand forecast for 2017 the result of an increase in the Minimum Take or Pay as per the applicable agreement.
[15] One spot LNG supply agreement and one firm LNG supply agreement.

PSE/TOTE. The expected in-service date of TOTE's first marine vessel is May 1, 2017. Of the total 1,190,688 GJ in incremental LNG demand in 2017, 833,482 GJ will be provided to PSE/TOTE under a spot LNG supply agreement from May 1, 2017 to December 31, 2017. The balance of 357,206 GJ will be provided to PSE/TOTE on a firm LNG supply agreement. The breakdown is as follows:

- The customer has estimated that they will require approximately 148,836 GJ of LNG per month beginning in May 2017.
- For the five month period from May 1 to September 30, 2017, FEI will supply approximately 744,180 GJ on a spot basis.
- Beginning on October 1, 2017, for the three month period from October 1 to December 31, 2017, 80% of the monthly volume, or 119,069 GJ per month, will be provided on a firm basis and the remaining 20%, or 29,767 GJ per month, will be provided on a spot basis.

4.2 FORECAST REVENUE, COST OF GAS AND DELIVERY MARGIN

Currently, FEI delivers CNG and LNG to the GGRR and non-GGRR stations under Rate Schedules 25 and 46.[16] FEI has used the forecast volumes from this appendix 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 25 and 46. This includes customers for which FEI does not construct the fueling station but delivers gas to the customer's location under approved FEI rate schedules. The LNG volume dispensed under Rate Schedule 46 also includes volumes provided to non-NGT customers, mainly for the purposes of power generation.

The following two tables identify, for the rate schedules 25 and 46, the forecast of CNG and LNG volumes sold, associated delivery margin at 2016 rates[17], cost of gas[18] (applicable for Rate Schedule 46 only), and revenue (delivery margin plus cost of gas).

Table B-5: Rate Schedule 25 CNG Forecast

Volume, Revenue, Margin under RS 25	2016A	2016P	2017F
Demand (GJ)	586,224	659,336	769,467
Total Delivery Margin ($ millions)	$ 0.728	$ 0.900	$ 0.991
Total Revenue ($ millions)	$ 0.728	$ 0.900	$ 0.991

16 As noted in Section 2.3 of this appendix above, Rate Schedule 6P applies to CNG provided at the Surrey Operations Centre for general public use only and as such has been excluded from this discussion. Please refer to Section 3 for the forecast of Rate Schedule 6P demand and revenues.

17 For this purpose, delivery rates exclude the delivery rate riders which are calculated separately.

18 The 2016 projected cost of gas is based on the GLJ Forecast Sumas Spot Price for April 1, 2016 for the year 2016 of $1.90 $US/MMBTU. The 2017 forecasted cost of gas is based on the GLJ Forecast Sumas Spot Price for April 1, 2016 for the year 2017 of $2.80 $US/MMBTU (exchange rate of 1 US$ = 1.32 CDN$, Conversion factor of 1.055056 GJ per 1 MMBtu is used to convert to GJ).

Table B-6: Rate Schedule 46 LNG Forecast[19]

Volume, Revenue, Margin under RS 46	2016A	2016P	2017F
Demand (GJ)	668,729	667,032	2,302,254
Total Delivery Margin ($ millions)	$ 3.076	$ 3.068	$ 10.802
Total Cost of Gas ($ millions)	$ 1.662	$ 1.586	$ 8.065
Total Revenue ($ millions)	$ 4.739	$ 4.654	$ 18.867

The volume, delivery margin, cost of gas and revenue forecasts are included in the financial schedules within this Application and serve to reduce the overall natural gas revenue requirement.

[19] A break out of the total Rate Schedule 46 demand into NGT and non-NGT categories is provided in Section 3.5.4 and shown in Figure 3-12 of Section 3.

5. NGT FUELING STATION SERVICES

A large component of FEI's NGT program consists of provisions to construct CNG or LNG fueling stations for the purpose of providing suitable fueling facilities for customers. FEI provides fueling station infrastructure under the two approved regulatory models, the FEI GT&C Section 12B Vehicle Fueling Stations, and the GGRR[20].

The Commission-approved GT&C Section 12B applicable fueling station agreements set 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 $12.000 million to own and operate CNG fueling stations and infrastructure and make expenditures of up to $30.500 million to own and operate LNG fueling stations and infrastructure.[21]

The following subsections discuss the existing approved fueling stations, forecast fueling station additions (including the forecast capital and operating costs embedded in the 2017 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 seven CNG fueling stations, is in the process of completing two additional CNG stations in 2016 and has one planned for construction in 2017. The CNG stations on the premises of FEI's Burnaby Operations Centre (Burnaby Operations) and the Mid Island Consumer Services Co-operative (Mid Island) fueling station in Nanaimo, BC, are currently under construction and are expected to be complete in July and August 2016, respectively.

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

[20] 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, currently held outside of FEI's rate base, to the general natural gas rate base. This treatment is consistent with the amended GGRR and Special Direction No. 5, which sets out the treatment of CNG and LNG services, including fueling station services, that forms part of FEI's natural gas class of service and natural gas rate base. If approved, FEI will include any projected LNG volumes associated with these assets as part of the LNG forecast demand in an evidentiary update.

[21] $12.0 million and $30.5 million total investment per utility over the regulation period, which ends March 31, 2018.

undertaken. The Waste Management of Canada Corporation (Waste Management) agreement was developed based on previously proposed GT&Cs, and was accepted "on an exception basis only".

Table B-7: CNG Fueling Stations Constructed by FEI

Customer/Station	Applicable Order Numbers	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

CNG fueling station customers pay a fixed monthly charge, a demand charge per GJ per month, and a variable delivery charge under Rate Schedule 25[22].

FEI has constructed and is operating LNG fueling stations for six customers. The table below summarizes the approvals granted for each of these customers. All of the LNG fueling stations, with the exception of the one on the premises of Vedder Transport Ltd. (the Vedder Station) , were constructed under the GGRR.

Table B-8: LNG Fueling Stations Constructed by FEI

Customer/Station	Applicable Order Numbers	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

The Vedder Station is also being used to provide LNG fueling services to Ledcor Resources and Transportation L.P., which was approved by Order G-57-14 on April 22, 2014. Denwill Enterprises Inc. (Denwill) and Westcan Bulk Transport Ltd. (Westcan Bulk Transport), (formerly Wheeler Transport Ltd.) are also permitted to receive fuel from the Vedder Station, approved on a permanent basis by Orders G-79-15 and G-80-15, respectively.

[22] Rate Schedule 25 is FEI's General Firm Transportation Service provides delivery service to larger volume customers who use gas typically for process load and generally has a higher load factor than residential and commercial customers due to the customers' consumption patterns. Customers under Rate Schedule 25 only pay delivery charges and must sign a contract with a natural gas marketer for the purchase of their natural gas commodity. On January 1, 2015 Cold Star commenced receiving service under Rate 5 General Firm Service, which has the same delivery charges as Rate Schedule 25, but also includes commodity charges. For forecast consistency FEI has included Cold Star's demand, revenue and margin within Rate Schedule 25.

Denwill is also receiving supply from the Arrow Transportation Systems Inc. (Arrow) fueling station, which was approved on a permanent basis by Order G-57-15.

FEI has filed two applications to the Commission requesting approval of rates for Arrow and Denwill to receive LNG fueling services from a station at the premises of Cool Creek Energy Ltd. (Cool Creek) on June 28, 2016 and July 4, 2016 respectively. FEI is currently awaiting Commission decisions on both applications.

5.2 *FORECAST FUELING STATIONS AND CAPITAL EXPENDITURES*

Based on the vehicle incentive expenditures to date and the forecast volume of natural gas demand for CNG and LNG, FEI is not projecting any new LNG fueling stations to be constructed under the GGRR model or GT&C Section 12B, in the remainder of 2016 or for 2017 (consistent with the 2016 and 2017 forecasts).

FEI is forecasting two new CNG fueling stations to be completed in the remainder of 2016, and one new CNG fueling station to be constructed in 2017. The following table provides the total projected and forecast number of FEI-owned stations as at December 31 for 2016 and 2017, respectively:

Table B-9: Forecast Total FEI Fueling Stations

	2016A	2016P	2017F
CNG Stations	9	9	10
LNG Stations	5	6	6
Total	**14**	**15**	**16**

Although five (5) LNG stations were forecast for 2016 in the 2016 Annual Review, there is now projected to be a total of six (6) LNG stations in 2016. The fueling station agreement with Vedder Resources was executed in October 2015, following the filing of the 2016 Annual Review.

The following table provides a summary of total capital expenditures projected in 2016 and forecast for 2017 related to fueling station additions.

Table B-10: NGT Fueling Station Capital Expenditures & Additions Forecast

$ millions	**2016A**	**2016P**	**2017F**
CNG Stations	$ 2.100	$ 2.300	$ 2.125
LNG Stations	-	-	-
Total	**$ 2.100**	**$ 2.300**	**$ 2.125**

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 stations for 2016 and 2017, the expenditures occur the same year that the assets are placed into service. The 2017 capital additions for the CNG and LNG stations can be found in Section 11, Schedule 4, Line 22, Column 4, under the Natural Gas for Transportation heading.

In 2016, capital expenditures of a total of approximately $2.3 million are projected for CNG stations and no capital expenditures were forecasted for LNG stations[23]. The 2016 Projection for CNG stations is higher than 2016 Approved due to the capital costs to construct a CNG station to serve two new customers, which were not included in the 2016 forecast because discussions with these customers did not occur until late 2015, after the 2016 Annual Review had already been filed. The capital cost for this station to serve these two new customers is partially offset by the capital cost of another CNG station that was forecast for 2016 but has been delayed to 2017.

In 2017, one new CNG fueling station is expected to be constructed for a total forecast cost of approximately $1.800 million, in addition to an expansion to an existing CNG fueling station with a total forecast cost of approximately $0.325 million. In 2017, FEI will apply to the Commission for approval of rates to recover the costs of the one CNG station, if FEI is able to reach contractual agreements with these customers, as well as for approval for the expansion of an existing CNG station.

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 the customer(s) of each fueling station through the rates charged to those customers as described in Section 5.4 below.

Based on FEI's experience in constructing and operating natural gas fueling stations, Table B-11 below shows the forecast O&M expenses for existing fueling stations, the two new CNG fueling stations to be constructed in 2016 and the additional new fueling station that will be constructed in 2017.

Table B-11: Forecast Annual CNG and LNG Fueling Station O&M

$ millions	2016A	2016P	2017F
CNG Stations	$ 0.424	$ 0.516	$ 0.723
LNG Stations	0.563	0.472	0.503
Station Subtotal	**$ 0.987**	**$ 0.988**	**$ 1.226**

5.4 *FORECAST FUELING STATION RECOVERIES*

The 2017 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.

[23] The capital expenditure for the Cool Creek Ltd. (Vedder Resources) LNG fueling station was incurred in 2015.

5.4.1 CNG and LNG Service Revenue Forecast

Based on the 16 CNG and LNG fueling stations identified in Tables B-8 and B-9 above, FEI has forecast fueling station recoveries of $3.693 million in 2017, which compares to 2016 projected recoveries of $2.438 million. The 2017 forecast uses the approved fueling station rates for the 13 completed fueling stations, and the 2 stations under construction, and estimated fueling station rates for the new fueling station forecast to be added in 2017.

Table B-12 provides a break down between CNG and LNG station recoveries by customer. The forecast revenue for the fueling station to be constructed in 2017 is based on fueling station rates that are not yet approved. As mentioned in Table B-1 of this appendix, all rates applicable to fueling stations are subject to a separate approval process with the Commission. 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 Service Revenue Forecast ($millions)[24][25][26]

CNG / LNG Service Revenue	2016A	2016P	2017F
CNG			
Customer 1	$ 0.269	$ 0.269	$ 0.274
Customer 2	0.177	0.177	0.180
Customer 3	0.054	0.054	0.055
Customer 4	0.178	0.179	0.838
Customer 5	0.159	0.159	0.162
Customer 6	0.041	0.046	0.054
Customer 7	0.273	0.273	0.332
Customer 8	0.046	-	0.196
Customer 9	0.033	0.036	0.073
Customer 10	-	0.006	0.012
Customer 11	-	0.050	0.123
Customer 12	-	0.006	0.014
Total CNG	**$ 1.230**	**$ 1.253**	**$ 2.313**
LNG			
Customer 1	$ 0.349	$ 0.348	$ 0.355
Customer 2	0.060	0.060	0.061
Customer 3	0.145	0.144	0.147
Customer 4	0.160	0.160	0.163
Customer 5	0.114	0.114	0.116
Customer 6	0.342	0.168	0.342
Customer 7	-	0.192	0.196
Total LNG	**$ 1.170**	**$ 1.185**	**$ 1.380**
Total CNG / LNG Service Revenue	**$ 2.401**	**$ 2.438**	**$ 3.693**

5.4.2 NGT Overhead and Marketing Recoveries Forecast

Pursuant to Order G-78-13, FEI has forecast for 2017 a recovery of overhead and marketing (OH&M) costs from NGT customers.

On August 21, 2015, FEI filed with the Commission a letter in response to Directive 5(II) of Order G-105-15[27], wherein FEI calculated the OH&M rate based on updated cost and volume

[24] Excludes compression revenue from Surrey Operations Pump. Other Revenue Schedule 23, Line 10 includes compression revenue from the Surrey Operations CNG pump of $0.034 million for a total of $3.727 million in 2017.
[25] Pursuant to Order G-105-15, the names of customers have been removed to preserve confidentiality.
[26] 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.
[27] Order G-105-15, Directive 5(II): *Recalculate the Overhead and Marketing (OH&M) Charge, using the most recent cost and volume forecast, and the same methodology as Order G-78-13, to determine if the $0.52/GJ OH&M Charge continues to be appropriate.*, issued June 18, 2015.

forecasts. FEI recommended that the OH&M rate remain unchanged at $0.52 per GJ. FEI further recommended that this OH&M rate continue to be applied to all fueling stations until it is reviewed as part of FEI's 2016 Rate Design Application. On September 30, 2015 the Commission's Performance Monitoring, Conduct and Compliance Division issued an acknowledgement letter indicating that no further action on this matter was required, effectively confirming the continuation of the OH&M rate of $0.52 per GJ as recommended by FEI until further order of the Commission.

As shown in Table B-13 below, the total forecast NGT OH&M revenue for 2017 is $0.332 million, which is calculated by multiplying he approved OH&M rate of $0.52 per GJ by the applicable[28] 2017 forecast CNG and LNG sales (GJ).

Table B-13: NGT Overhead and Marketing Revenue Forecast

NGT Overhead and Marketing Revenue	2016A	2016P	2017F
Applicable Volume (GJ)	505,131	509,481	638,891
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.263**	**$ 0.265**	**$ 0.332**

[28] This volume is limited to CNG and LNG contract volume delivered through an FEI-owned CNG or LNG fueling stations.

6. ENABLING LNG DEMAND FULFILMENT

Two aspects of LNG service that are interrelated with the NGT program are:

- The optional tanker transportation service provided to LNG customers under Rate Schedule 46 (the LNG Transportation Service); and
- FEI's LNG facility upgrades and expansions.

LNG Transportation Service is part of Rate Schedule 46 and the LNG tanker expenditures are a prescribed undertaking under the GGRR,[29] for which cost recovery is provided in section 18 of the Clean Energy Act. FEI has completed construction of the LNG tanker truck load-out at its Mt. Hayes LNG facility, and the expenditures for the construction were part of Prescribed Undertaking 3 described above.

6.1 *LNG TRANSPORTATION SERVICE UNDER RATE SCHEDULE 46*

6.1.1 LNG Tanker Capital Expenditure Forecast

On March 30, 2016, FEI applied to the Commission for approval for amendments to Rate Schedule 46 – LNG Sales, Dispensing and Transportation Service. FEI applied for approval (among other things) to add two new categories of tanker charge to the Rate Schedule 46 Table of Charges in order to recover the cost of additional tankers from applicable customers. The two new charges were the tridem tanker charge at $317 per day or partial day, and the marine equipped tridem tanker charge at $445 per day or partial day. On June 9, 2016, the Commission issued Order G-85-16, approving the proposed amendments to Rate Schedule 46 effective June 1, 2016, which included the two new categories of tanker charge.

FEI is projecting approximately $3.110 million in capital expenditures in 2016 and forecasting $0.870 million in 2017 for the purchase of a total of four LNG tanker trailers in 2016, three of which are marine equipped tridem tankers, and one tridem LNG tanker trailer in 2017, to serve the growing LNG demand. In early 2016, FEI entered into an agreement to place an order and pay a deposit amount of approximately $0.653 million to vendors for the purchase of three marine equipped tridem tankers and $0.125 million for one tridem tanker. The estimated balance of $2.332 million will be paid to the vendors by the end of 2016. The estimated approximate capital cost for each of these tankers is approximately $0.870 million each, which is higher in cost than FEI's existing standard tankers. The tridem tankers have been optimized to have a larger capacity than that of FEI's existing standard tankers and the three marine equipped tridem tankers will include customized marine fittings and pumps in order to serve specific requirements of the marine customers. The first marine equipped tridem tankers will

[29] Prescribed Undertaking 2.

begin operation in September, 2016 and the others will be phased in over 2016 and 2017.[30] The costs of the marine equipped tridem tankers will be offset by the approved Rate Schedule 46 LNG applicable tanker charge. FEI forecasts to place an order for one more marine equipped tridem tanker in 2017 at a cost of approximately $0.870 million to service additional forecasted demand that is expected to come online in 2018 and beyond.

6.1.2 Tanker O&M Forecast

FEI is forecasting 2017 O&M expenses of $0.183 million for LNG tanker trailers and $0.085 million for Emergency Response and Preparedness (ERAP) coverage, which is required to respond to emergency situations related to the transport of LNG from FEI's facilities to customers' sites. LNG is sold under Rate Schedule 46 as free-on-board (FOB) at the LNG facility. Under Transport Canada Regulations, as the producer of a dangerous good as defined by Transport Canada, FEI is required to provide a registered Emergency Response Assistance Plan (ERAP) for the LNG product while in transit. The plans lay 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 on LNG.

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 2017 tanker rental revenues related to the existing tankers as shown in Table B-14 below based on the 2016 projected tanker deliveries plus additional deliveries to account for incremental 2017 forecast LNG volumes. As described in Section 6.1.1 of this appendix, FEI is acquiring three marine equipped tridem tankers in 2016 to service the expected marine load. The table below summarizes the expected revenue per the current rate and the projected new rates to be charged on the new tankers[31]. The current applicable tanker charge per day or partial day is as per the Table of Charges for LNG Transportation Service of Rate Schedule 46[32].

[30] BC Ferries will put into operation 3 marine vessels beginning in Q4 2016, and Seaspan will put into operation 2 marine vessels in Q4 2016.
[31] Table B-14: Tanker Rental Revenue of the 2016 Annual Review outlined "Larger Tri-Axle Tanker Rental Deliveries", which included both volumes for tridem tankers and marine equipped tridem tankers for 2015 projected and 2016 forecast.
[32] OIC No. 557 and Commission Order G-85-16.

Table B-14: LNG Tanker Rental Revenue

Tanker Rental Revenue	2016A	2016P	2017F
Standard Tanker Rental Deliveries	768	768	768
Rate ($/Delivery)	$ 264	$ 264	$ 269
Sub Total ($ millions)	$ 0.203	$ 0.203	$ 0.207
Tridem Tanker Rental Deliveries	16	-	240
Rate ($/Delivery)	$ 380	$ 317	$ 323
Sub Total ($ millions)	$ 0.006	$ -	$ 0.078
Marine Equipped Tridem Tanker Rental Deliveries	-	16	360
Rate ($/Delivery)	$ -	$ 445	$ 454
Sub Total ($ millions)	$ -	$ 0.007	$ 0.163
Total Tanker Rental Revenue ($millions)	**$ 0.209**	**$ 0.210**	**$ 0.448**

6.2 *LNG FACILITY UPGRADES AND EXPANSIONS*

Capital expenditures at the Mt. Hayes and Tilbury LNG facilities are spent to support the growth of LNG demand and the NGT market and are discussed further below. As mentioned above, the expenditures are allowed for recovery by provincial legislation.

6.2.1 Mt. Hayes Truck Load-Out Facility

The Mt Hayes load-out project was the addition of tanker loading equipment at the facility with the capital expenditures occurring in 2014. The project was placed into service in 2015 at a completed capital cost of $4.800 million.

6.2.2 Tilbury Expansion Project

The current expansion of the Tilbury LNG facility is for the addition of up to 34,000 GJ per day of liquefaction capability and storage capacity of about 1.1 petajoules (PJ). The expansion of the Tilbury LNG facility will support the growth of LNG demand for domestic and regional use for the next number of years.

The project is expected to be completed at the end of 2016 and has been included in rate base starting January 1, 2017. See Section 7.2.2 of the Application for further information.

7. CONCLUSION

The following table provides a summary of the total O&M, capital and revenue forecast included in the 2017 forecast revenue requirement.

Table B-15: Summary of 2017 Forecast Revenues and Costs ($ millions)

Particular	2017	Reference
Incentives (deferral additions)	$ 13.548	Section 11, Schedule 11, Line 14, Column 4
Capital Expenditures		
Fueling Stations	2.125	Section 11, Schedule 4, Line 26, Column 4
Tankers	0.870	Section 11, Schedule 4, Line 26, Column 4
Tilbury Expansion	12.432	Section 11, Schedule 5, Line 13, Column 2
Total Capital Expenditures	$ 15.427	
Revenue		
Delivery Margin	$ 11.793	Appendix B, Table B-5 and B-6
Fueling Station	3.693	Appendix B, Table B-12
Overhead & Marketing	0.332	Section 11, Schedule 23, Line 7, Column 3
Tanker Rental	0.448	Section 11, Schedule 23, Line 6, Column 3
Total Revenue	$ 16.266	
O&M		
Fueling Stations	$ 1.226	Appendix B, Table B-11
Tankers	0.183	Appendix B, Section 6.1.2
ERAP	0.085	Appendix B, Section 6.1.2
Total O&M	$ 1.494	

Appendix C

PRIOR YEAR DIRECTIVES

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-101-12 – FEI KINGSVALE-OLIVER REINFORCEMENT PROJECT (KORP) STAGE 2A PROJECT DEVELOPMENT COSTS AND ACCOUNTING TREATMENT DECISION (DATED JULY 23, 2012)					
1.	3, 8, 9	No. 3	***FEI KORP Stage 2a Deferral Account:*** FEI is directed to establish a new non-rate base deferral account for recording of Stage 2a feasibility expenses with treatment of interest rate and deferral period to be determined at the next Revenue Requirement.	FEI has proposed that this account be discontinued.	Section 12.4.1
G-138-14 – FEI MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
2.	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.	Not yet started.	N/A
3.	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-15-15 - FEI MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019 APPLICATINO FOR RECONSIDERATION AND VARIANCE					
4.	3	6	***New Code of Accounts*** FEI is directed to file a proposal to deal with any benchmarking difficulties that may arise from the use of its New Code of Accounts by no later than the third annual PBR Review.	Completed.	Section 12.3.2

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-86-15 – FEI ANNUAL REVIEW FOR 2015 DELIVERY RATES					
5.	8	3	***Residential Use Per Customer*** The Panel directs FEI to review alternative methodologies and develop one that overcomes the identified shortcomings and more accurately predicts actual average UPC for the next annual review.	Completed	Appendix A-4
6.	9	5	***Commercial Use Per Customer*** The Panel directs FEI to include commercial customers as part of its review of alternative methodologies for forecasting UPC for the next annual review.	Completed	Appendix A-4
7.	10	8	***Commercial Customer Additions*** The Panel directs FEI to consider alternative methods for forecasting commercial customer additions which are appropriately sensitive to the business cycle. FEI is to provide an analysis of these alternatives in its next annual review application.	Completed	Appendix A-4
8.	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
9.	14	12	***Demand Forecast Presentation*** The Panel accepts FEI's proposal to include in its next Annual Review application a fulsome description of its demand forecast methodology. The Panel also directs FEI to include information that in this proceeding was obtained through staff and intervener information requests as well as the analyses of alternative forecasting methodologies directed in this Decision. This information is to include: • Historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals; • The results along with an explanation of various aspects of the Industrial Survey used by FEI to forecast industrial demand; Furthermore, the Panel directs FEI to include the most recent ten years of historical actual data where possible.	Completed - information provided.	Section 3 (10 years of historical data); Appendix A2 (Historical forecast and actual data); and Appendix A3 (Industrial survey explanation)

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
10.	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)
11.	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
12.	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
13.	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
14.	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
15.	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 1-2 in Section 1.4.2

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-97-15 – FEI FORT NELSON 2015-2016 REVENUE REQUIREMENTS AND RATES DECISION					
16.	17	14	***Reallocation of Capital Between the Entities:*** The Panel is not persuaded that the allocated amounts being charged to FEFN for Intangible Plant additions are appropriate...FEI is further ordered to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how these costs can be most appropriately and equitably handled going forward given the current PBR Plan in place.	Completed	Section 7.2.1.1
17.	20	16	***Communication and Line Heater Fuel Costs*** The Panel considers moving the communication and line heater fuel costs to Of concern to the Panel is the movement of communication and line heater fuel costs which were previously centralized in FEI to FEFN… In addition, FEI is directed to identify any other cases where FEI Base Capital or O&M amounts have been allocated to FEFN since approval of the PBR Plan. FEI is further directed to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how the communication and line heater fuel costs can be most appropriately and equitably handled going forward given the current PBR Plan.	Completed	Section 6.2.1
G-120-15 – FEI-FBC PBR CAPITAL EXCLUSION CRITERIA					
18.	17	4	***Capital ExpendituresExceeding 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					
19.	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.	

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
20.	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
21.	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
22.	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 now agrees to Schedule 1 of Section 11

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 C-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 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

Table C-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	**$0.3 million** This includes costs for IT and facilities.	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

1 **Table C-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

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1 **Table C-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 responsible for providing Information Systems (IS) Customer and Infrastructure Services to FEI. 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

2

Appendix D

DRAFT ORDER

British Columbia Utilities Commission

Sixth floor, 900 Howe Street
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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 2017 Delivery Rates

BEFORE:
D. J. Enns, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
B.A. Magnan, 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. On July 15, 2016, FEI filed a proposed regulatory timetable for the filing and review of the annual review materials in advance of filing its Annual Review of 2017 Rates materials;

C. On July 29, 2016, the regulatory timetable for the FEI Annual Review of 2017 Rates proceeding was established by Order G-122-16 and included, among other things, an anticipated date of August 3, 2016 by which FEI would file its Annual Review materials;

D. On August 2, 2016, FEI submitted its Annual Review for 2017 Rates Application materials (Application);

E. On October 12, 2016, a workshop was held in Vancouver, BC and on October 19, 2016, FEI filed its responses to undertakings;

F. The Commission has reviewed the Application and evidence filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59-61 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. FortisBC Energy Inc.'s (FEI) permanent delivery rates for all non-bypass customers, effective January 1, 2017, resulting in an increase of 1.2 percent compared to 2016 delivery rates, are approved, with the increase to be applied to the delivery charge, holding the basic charge at existing levels.

.../2

2. Deferral account changes as described in Sections 7.5 and 12.4 are approved:

    a. Creation of a rate base deferral account for the All-Inclusive Code of Conduct/Transfer Pricing Policy regulatory proceeding with a one year amortization period, commencing in 2017.

    b. A three year amortization period for the existing 2016 Cost of Capital Application deferral account, commencing in 2017.

    c. A five year amortization period for the existing Emissions Regulations deferral account, commencing in 2017.

    d. Discontinuance of the non-rate base deferral account for the Kingsvale-Oliver Reinforcement Project Feasibility Costs.

3. The Rate Stabilization Deferral Account riders for Mainland customers effective January 1, 2017, in the amounts set out in Table 10-7 in Section 10 of the Application are approved.

4. The Phase-in Rate riders effective January 1, 2017, in the amounts set out in Table 10-7 for Mainland customers and Table 10-11 for Vancouver Island and Whistler customers in Section 10 of the Application are approved.

5. The Revenue Stabilization Adjustment Mechanism riders, effective January 1, 2017, in the amounts set out in Table 10-12 in Section 10 of the Application are approved.

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

Attachment (Yes? No?)