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June 10, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

Enclosed please find FEI's Application for Approval of a Multi-Year Performance Based Ratemaking (PBR) Plan for the years 2014 through 2018.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (e-mail only): FEU 2012-2013 RRA Registered Parties

FortisBC Energy Inc.

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

Volume 1 - Application

June 10, 2013

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A: OVERVIEW AND INTRODUCTION

1. APPLICATION OVERVIEW

FortisBC Energy Inc. (FEI or the Company) seeks Commission approval of a multi-year performance based ratemaking (PBR) plan for the years 2014 through 2018 (the PBR Plan or the 2014 Plan), including approval of rates for 2014 in accordance with the PBR Plan. A detailed list of the approvals sought is set out in Section A2.

FEI's primary objectives for its PBR Plan are:

1. To enforce FEI's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for the upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

FEI's proposed PBR Plan builds on the successful components of the PBR plan that was approved for FEI for 2004-2007 and extended for 2008-2009 (the 2004 Plan), with improvements to a number of elements. Similar to the 2004 Plan, the proposed PBR Plan establishes incentives for those elements of cost of service over which the Company has the greatest control: operating and maintenance (O&M) and capital expenditures. The formula results in targeted levels of spending in these areas that are lower than FEI's forecast of O&M and capital costs over the five year period as set out in Section C. This provides the Company with an incentive to invest in new efficiencies to meet the targets under the formulas. In addition, the PBR Plan includes a sharing mechanism that provides an opportunity for customers to share in the benefit to the extent that FEI exceeds the formula-based targets. For those items over which FEI has limited or no control, the PBR Plan maintains the same regulatory treatment as was used in the 2004 Plan through the use of flowthroughs and Annual Reviews. The PBR Plan provides "off-ramps" should financial results or performance fall outside a band of reasonableness.

The elements of the PBR Plan are set out in Table A1-1 below:

Table A1-1: Summary of 2014 PBR Plan Proposal

Element	PBR Plan
Term	A five-year term from 2014-2018 is proposed.
Inflation Factor (I-Factor)	A weighted average of BC Average Weekly Earnings (AWE) for labour costs and BC-CPI for other O&M costs will be used to determine the I-factor, which will be reforecast annually.
Productivity Improvement Factor (X-Factor)	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M is proposed. 2013 approved O&M expenditures (with adjustments) are adopted as the base O&M The O&M formula will adjust the prior year's formula O&M by forecast customer growth and (I-X). O&M will not be rebased during the PBR term but will be subject to true-up for actual customer growth.
Controllable Expenses – Capital	A formula based approach for Capital is proposed using 2013 approved capital expenditures (with adjustments) as the base. Two formulas will be applied. Growth Capital is tied to forecast service line additions and other regular capital is tied to forecast growth in average customers. The (I-X) escalation factor is also applied to both formulas. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%. Formula amounts will be subject to true-up for actual cost driver results (i.e. service line additions or average customers).
Flow Through Expenses and Revenues	Revenues and non-controllable costs are forecast each year and flowed through in rates each year in the Annual Review Process.
Exogenous Factors	Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and Commission decisions will be flowed through in rates.
Earnings Sharing Mechanism	The PBR includes a 50/50 earnings sharing mechanism for returns above or below the approved return on equity
Efficiency Carry-Over Mechanism	An expanded Efficiency Carry-over Mechanism is proposed based on a rolling 5-year benefit calculation derived from O&M and capital efficiencies achieved each year.
Service Quality Indicators	10 SQIs (7 SQIs with a target benchmark and 3 informational measures) are proposed that deal with emergency response, customer service (telephone service, billing), employee safety and meter exchanges.
Mid-Term Review and Off Ramps	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	Annual reviews are also proposed for this PBR.

FEI's PBR experts, Black and Veatch (B&V),[1] have studied the available PBR methodologies and provided their recommendations on FEI's proposed PBR model (Appendix D1, Comparison of Recent Canadian PBRs). They conclude that there is no one "right" PBR model, and that the

[1] Appendix D3 contains the curriculum vitae of Russell Feingold and H. Edwin Overcast of B&V.

framework adopted for FEI should be in keeping with FEI's specific circumstances. B&V also identified some theoretical and practical issues with aspects of the plans developed in other jurisdictions that do not exist with the model being proposed by FEI. FEI's proposed PBR Plan incorporates a more aggressive "stretch" productivity factor than is suggested by B&V's research of other North American utilities (Appendix D2, Estimating Total Factor Productivity). FEI's model produces lower rate increases over the five year period than a revenue cap model of the type approved by the Alberta Utilities Commission.

Overall, FEI believes that the proposed PBR Plan is an appropriate model that will encourage FEI to seek efficiencies in its operations over the term of the PBR plan for the benefit of both customers and the Company, while maintaining safe, reliable and customer-oriented utility service. B&V, who have provided input in the preparation of both the PBR Plan and Section B of the Application, endorses the overall proposed PBR Plan as being reasonable in the circumstances of FEI, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regard the appropriate productivity factor as being approximately zero, based on the TFP study they conducted and the specific elements of the proposed PBR Plan. In other words, FEI's proposal is more favourable to customers than they would recommend. FEI is nonetheless comfortable with the proposal as part of an overall package. Section B of the Application provides a review of PBR in general, a review of PBR regimes approved in other jurisdictions and more detailed discussion of the proposed PBR Plan.

FEI has provided forecasts of demand, revenue, O&M, and capital for the full 2014-2018 term (the PBR Period) in Section C of the Application. The 2014 through 2018 forecasts are included for reference purposes and represent a high level forecast of future trends and upcoming challenges for FEI. As FEI's proposed rates are based on the PBR Plan, FEI's cost of service forecasts should not be the focus of this proceeding. FEI has also provided an historical review of O&M expenditures since 2010. This historical review demonstrates that FEI has implemented a renewed focus on productivity which has resulted in efficiencies and sustainable savings. These sustainable savings have been incorporated into the 2013 Base O&M to which the O&M formula in the PBR Plan will be applied.

Section D of the Application adresses the Company's financing activities and requirements, taxes, changes in the accounting policies and procedures followed by the Company, and deferral accounts and amortization periods.

FEI's deferral accounts include rate base and non-rate base deferrals for Energy Efficiency and Conservations (EEC) measures. As set out in Appendix I, FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC Energy (Whistler) Inc. (FEW) (together, the FortisBC Energy Utilities or FEU) are seeking acceptance of an EEC portfolio over a five year term. The EEC expenditures under the FEU's EEC Plan (Appendix I1) are approximately at the same levels as currently approved for 2013. The FEU are seeking the continuation of the existing EEC framework, with the addition of: the administration of EEC funds by a neutral third party in cases where EEC funds are provided to projects with a third party thermal energy component;

endorsement of spillover and attribution of savings from codes and regulations for reporting purposes; and the ability to allocate funds to new programs without prior Commission approval over the five-year period.

Section E provides the financial schedules filed in support of the 2014 delivery rates proposed in this Application. The proposed 2014 non-bypass delivery rates are approximately 1.7 percent lower than the existing 2013 interim rates. This decrease is due to two factors. The first is the impact of the Generic Cost of Capital Phase 1 Decision (GCOC Decision) which decreases delivery rates by approximately 2.4 percent.[2] The second is a delivery rate increase of approximately 0.7 percent that results from the PBR Plan and demonstrates the continuing benefits of the Company's productivity and customer focus.

In its 2012-2013 RRA Decision,[3] the Commission made the following comments in its discussion of FEI's 2004 Plan:

> *"The Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements…*
>
> *In the view of the Commission Panel, the most important lesson to be learned from the PBR period was not specifically addressed by any of the parties. We refer directly to the success of PBR…However, the Commission Panel believes the success was not only in the amount of savings which was achieved, but perhaps more importantly, in the fact that when presented with a challenge, the FEU took the necessary steps to ensure the cost targets set during PBR were not only met but consistently exceeded. Moreover, this was achieved with no indication that the safety or reliability of the system was in jeopardy…*
>
> *In British Columbia, PBR, combined with the Negotiated Settlement Process has played a role within the rate setting process of FEI. Starting in 2004 and lasting through 2009 FEI operated in a PBR environment. During this period FEI was very successful as targets were met and the Companies note that shared earnings benefits flowing to customers and shareholders totalled $67.5 million each over the six years."*

FEI agrees that the 2004 Plan and the negotiated settlement process that produced it were a success. While FEI's proposed PBR Plan is similar to the 2004 Plan, FEI's going-in rates for this PBR Plan already incorporate a number of productivity savings. These productivity savings include both those that were achieved in the 2004 Plan through the Utilities Strategy Project and

[2] FEI will be providing an Evidentiary Update to this Application that will reflect the 2013 permanent delivery rates once those rates are finally determined.

[3] British Columbia Utilities Commission, *In the Matter of The FEU 2012-2013 Revenue Requirements and Rates*, Decision and Order G-44-12, dated April 12, 2012.

other initiatives, and those that have been realized in the 2012-2013 period through a renewed productivity focus. In addition, FEI's business environment has changed considerably since 2009, so that the previous PBR period is not directly comparable in terms of customer growth and energy policy. As a result, it will be challenging for this PBR Plan to produce the same level of savings that were realized under the 2004 Plan. Nevertheless, FEI believes that the proposed PBR Plan will continue to provide a sound framework to challenge the Company to maintain its productivity improvement culture, to the benefit of both customers and the Company.

2. APPROVALS SOUGHT

In this Application, FEI is seeking an Order of the Commission granting approvals required to implement a five-year PBR Plan. The approvals sought are described in terms of their main categories below.

PBR Plan

1. Approval pursuant to sections 59 to 61 of the Act of the PBR mechanisms set out in Section B of this Application for setting delivery rates for the years 2014-2018.

Delivery Rates

2. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for all non-bypass customers effective January 1, 2014, resulting in a decrease of 1.7 per cent compared to 2013 interim delivery rates, with the decrease to be applied to the delivery charge, holding the basic charge at 2013 levels.
3. Approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2U, 2X, 3, 3U, 3X and 23 effective January 1, 2014 of a credit amount of $0.118/GJ as set out in Section E Schedule 63 of the Application.

Deferral Accounts

4. Approval pursuant to sections 59 to 61 of the Act of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI as set out in Section D4 and Appendices F4 and F5 of the Application and summarized in the following table.

Type Of Change	Account	Company	Reference
New Account	2014 - 2018 PBR Application Costs	FEI	Section D4.1.1; amortization period of 5 years commencing January 1, 2014
	TESDA Overhead Allocation Variance	FEI	Section D4.1.2; disposition of account will be addressed in 2014 Annual Review
Amortization Period Change - New or Modified	Midstream Cost Reconciliation Account	FEI	Section D4.2.1; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Revenue Stabilization Adjustment Mechanism	FEI	Section D4.2.2; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Pension and OPEB Variance	FEI	Section D4.2.4; change from 3 year amortization period to a 12 year amortization period (EARSL), commencing January 1, 2014
	Customer Service Variance Account	FEI	Section D4.2.5; 5 year amortization period, commencing January 1, 2014

Type Of Change	Account	Company	Reference
Other	Energy Efficiency and Conservation	FEU	Section D4.2.6 The continuation of the FEI EEC Incentive non-rate base deferral account attracting AFUDC, approved by Commission Order G-44-12, to capture the actual as spent costs above the amount forecast in rates, up to the approved funding envelope, for 2014 through 2018, and to transfer the FEI portion of the balance to the FEI EEC rate base deferral account in the following year and recover the amount transferred over a ten year period beginning the year in which the balance is transferred. Additionally, FEI is seeking to transfer the FEI portion of the balance in this deferral as at December 31, 2013 to the FEI rate base EEC deferral account and to amortize the amounts in rates over 10 years beginning in 2014
	Biomethane Program Costs	FEI	Section D4.2.7; inclusion of application costs related to the FEI Biomethane Post Implementation Report
	NGV for Transportation Application	FEI	Section D4.2.8; inclusion of Rate Schedule 16 application costs[4]
	Generic Cost of Capital Application Costs	FEI	Section D4.2.9; amortization period of 2 years commencing January 1, 2014
	Amalgamation and Rate Design Application Costs	FEI	Section D4.2.10; transfer FEI's portion of the balance to rate base January 1, 2014, amortization of 3 years commencing January 1, 2014
	Residual Delivery Rate Riders	FEI	Section D4.2.11; inclusion of new residual balances for Rate Riders 3, 4 and 8
	On-Bill Financing Pilot Program	FEI	Section D4.3.1; transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and continue to recover the balance from OBF pilot program customers over approximately a ten year period until the account is fully recovered.
Discontinuance	Southern Crossing Pipeline Tax Reassessment	FEI	Section D4.4.2; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015
	Tilbury Property Purchase (Subdividable Land)	FEI	Section D4.4.3; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016
	CNG and LNG Recoveries	FEI	Section D4.4.4; discontinuation of this account effective January 1, 2015
	BFI Costs and Recoveries	FEI	Section D4.4.5; discontinuation of this account effective January 1, 2014
	Overhead and Marketing Recoveries from NGT Class of Service	FEI	Section D4.4.6; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016

[4] Pursuant to Commission Order G-88-13 received on June 4, 2013, Rate Schedule 16 Application Costs will be addressed through an Evidentiary Update to this Application once the Rate Schedule 16 Decision has been fully evaluated

Type Of Change	Account	Company	Reference
	2011 CNG and LNG Service Costs and Recoveries	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Olympic Security Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	IFRS Implementation Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2009 ROE and Cost of Capital Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2010-2011 Revenue Requirement Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2012-2013 Revenue Requirement Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	CCE CPCN Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Deferred Removal Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	US GAAP Conversion Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	US GAAP Transitional Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Mark to Market - Customer Care Enhancement Project	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2014

Accounting Policies

5. Approvals pursuant to sections 59-61 of the Act of changes to the following accounting policies to be used in the determination of rates for FEI effective January 1, 2014:

(a) Modification to the approved Lead Lag days with the removal of the HST lead days and the insertion of GST and PST lead days as set out in Section D3.2 of the Application.

(b) Inclusion of the retiree portion of pension and OPEB expenses in benefit loadings for O&M and capital as set in Section D3.1 of the Application.

(c) Capitalization of the annual software costs paid to vendors in support of upgrade capability as set out in Section D3.1 of the Application.

(d) Depreciation to commence January 1 of the year following when the asset is placed into service as set out in Section D3.3 of the Application.

(e) A depreciation rate of 12.5% for asset class 484 Vehicles as set out in Section D3.1 of the Application.

(f) Approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application.

6. 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 2014-2018 PBR Period as set out in Section C2.3 of the Application.

7. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and FEI and for Shared Services as between FEI and FEVI, and between FEI and FEW, as reflected in the Corporate Services Agreement and Shared Service Agreements as described in Section D3.6 of the Application. Approval of these cost allocations is subject to FEVI and FEW receiving regulatory approval for the same allocation in their next RRA filings.

Energy Efficiency and Conservation (EEC) As Set out in Appendix I of the Application

In this Application, the FEU are also seeking approvals to continue their EEC programs for the next five years. The approvals sought by the FEU together are as follows:

8. Acceptance pursuant to section 44.2(a) of the Act of the following EEC expenditure schedules for the FEU to be spent on the EEC program areas described in Appendix I of the Application: Up to $34.353 million for 2014, $37.303 million for 2015, $37.358 million for 2016, $37.664 million for 2017, and $38.982 million for 2018.

9. Continuation of the EEC framework approved by the Commission, with the following changes:
   a. Approval of the administration by a neutral third party of EEC funds provided to projects with a third party thermal energy component.
   b. Approval of the incorporation of spillover effects and the attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis, for the purpose of reporting on cost effectiveness in the EEC Annual Report pursuant to section 43 of the Act.
   c. Approval for the FEU to transfer funds within a program area to a new program without prior Commission approval, provided that the new program is in accordance with the DSM Regulation, EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

FEI's proposed regulatory process for this Application is set out in Section A7 below. FEI has provided a Table of Concordance with past directives in Appendix C1 and a Draft form of Order sought in Appendix J. In the following three sections, FEI discuss the productivity and customer focus as well as its organizational performance and monitoring.

3. PRODUCTIVITY FOCUS

3.1 PRODUCTIVITY FOCUS

A priority for FEI and its employees is to improve productivity and realize efficiencies to more effectively manage rates for our customers while maintaining a customer service focus. Employees are encouraged to assess work and ensure that it is being performed as efficiently and productively as possible. When evaluating productivity opportunities, maintaining a customer focus remains a priority, helping strike a balance between lower costs while providing the appropriate level of service and quality.

During 2012, this productivity focus led to a number of initiatives and opportunities that contributed to sustainable O&M savings realized by the FEU (or the gas utilities). Employees were asked to challenge embedded practices and rethink work while maintaining appropriate service. As a result, efficiencies were realized from streamlining processes, leveraging technology and optimizing opportunities for integration with FortisBC Inc. (FBC or the electric utility).

In 2012, the Company was able to achieve a number of efficiency successes. These included significant annual savings of approximately $9 million related to implementing a new manual meter reading contract. Starting in 2013, the new arrangement provides improved meter reading service at a lower cost than the previous arrangement.

Streamlining and enhancement of processes contributed to increased productivity and provided increased service to customers. FEI reduced the customer wait time for installation of a new gas service not requiring a permit by implementing process changes. An on-line self-help Home Energy Calculator was introduced allowing residential customers the ability to compare energy costs of operating home appliances at the customers' convenience while reducing the amount of support required from customer service staff. The meter exchange process was improved using live-agent calls, in addition to letters, which led to increased customer satisfaction with the process as well as increased efficiency. Process enhancements in the GIS area have enabled faster drawing production in support of distribution main expansions and alterations and more efficient use of resources. Simplification of various physical processes within Materials Services contributed to reduced cycle times.

Productivity gains from leveraging technology include enhancements in support of the BC One Call process which resulted in significant productivity gains and provides the Company the ability to respond faster to customer inquiries. In the supply chain services, business processes were simplified using automation.

Integration with the electric business enabled certain efficiencies to be achieved. Integration driven opportunities involved a common management team, common processes and sharing of resources. Additionally, integration driven efficiencies were not only focused on lowering costs but also on increasing the capacity of both the gas and electric businesses and providing employee growth and development opportunities.

Integration driven opportunities in 2012 include the Human Resources (HR) department where the employee development, talent sourcing, labour relations, compensation administration, pension and benefits administration and corporate HR functions were integrated and aligned between gas and electric utilities. Roles were redesigned and automated technology was implemented. The Communications and External Relations groups were also able to realize productivity improvements through sharing of resources across the two companies. In the Environmental Health and Safety department, many processes, programs, operating standards and roles have been aligned between the gas and electric utilities, contributing to the efficiencies realized.

For further discussion and other productivity examples, refer to the O&M departmental review in Section C3.

3.2 *SHARING OF GAS AND ELECTRIC SERVICES*

Sharing of services across the gas and electric businesses capitalizes on some of the efficiency opportunities available. By leveraging the available employee knowledge base and skillsets of both the gas and the electric businesses, consistency of service and flexibility in staffing is improved.

In 2012, the gas and electric utilities approached vacancies as an opportunity to employ more temporary employees and shift work to contractors in order to provide flexibility in meeting peak demands, allowing the Company to shed labour costs more easily. In addition, the utilities took the opportunity to streamline and align roles through job redesign. This resulted in efficiencies being realized through a common management team. To varying degrees, leadership positions are now shared between the FEU and the FBC. In these circumstances employees of one entity cross charge an appropriate share of their time to the other entity to allocate costs appropriately. As set out in the 2012-2013 RRAs for both utilities, the cross charges include a fully loaded wage.

For 2013, sharing of labour resources between the gas and electric businesses is forecasted at a net amount of approximately $0.5 million, with approximately $2.5 million being allocated from gas to electric and approximately $3 million from electric to gas. The forecasted labour dollars represent sharing of labour resources between the different gas and electric departments. Instead of using a Shared Services cost allocation model similar to that approved for allocating shared services costs between FEI and FEVI/FEW, the traditional timesheet allocation approach is being used. The traditional timesheet allocation approach provides the benefits of a more specific and tailored allocation of shared services costs based on actual and/or specific estimates.

FEI will evaluate the feasibility of introducing a Shared Services cost allocation approach during the PBR Period similar to that used between FEI and FEVI/FEW. The ability to implement such an approach depends on the nature of future integration opportunities and having the necessary conditions in place for shared services such as common management, common IT platforms and common policies and processes. The introduction of a cost allocation model would provide a representative approach to allocate costs and efficiencies between gas and electric, while minimizing the administrative efforts associated with the timesheet allocation approach.

3.3 PRODUCTIVITY FOCUS – 2013 AND ONWARD

Productivity gains and efficiency review activities will continue in the future, similar to the path followed in 2012, with the emphasis on managing costs and working more efficiently and effectively.

Further opportunities may emerge and will be evaluated depending on the circumstances and potential benefits to customers. Future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome some challenges. These challenges include concerns raised by unions representing gas and electric employees around shifting of unionized work from one entity to another, and the need to transition to common IT platforms before more harmonization of business processes can occur. Differences in the nature of the gas and electric operations also pose challenges and limit the breadth of opportunities available. While the Company will continue its efforts to investigate productivity opportunities, future progress is expected to be considerably slower given the highlighted challenges, and may require an upfront investment in IT systems or other initiatives to achieve significant and sustainable savings.

In providing value for our customers while delivering safe and reliable service at the most reasonable cost, a productivity focus is a requirement and is engrained into the Company. The implementation of the PBR Plan proposed in this Application will result in a continuation of this focus through the PBR Period, and in an equal sharing with customers of the resulting incremental savings above the productivity factor built into customer rates.

4. CUSTOMER FOCUS

4.1 *INTRODUCTION*

An underlying principle of PBR is that the regulatory construct should align the interests of customers and the utility company. Under PBR, the utility is provided incentive to find efficiencies in its operations and new revenue opportunities, while providing safe and reliable service, and maintaining (or improving) customer service levels. Customers benefit from the efficiency initiatives undertaken in PBR by having lower rates and the utility benefits from additional income deriving from superior performance as compared to the productivity levels embedded in rates. FEI places high importance on providing value to customers in the utility services delivered and believes the proposed PBR Plan provides the desired alignment between the customers' and the Company's interests. This section discusses our customer focus and initiatives to retain existing customers and attract new ones that will continue throughout the PBR period.

4.2 *STRENGTHENING CUSTOMER FOCUS*

Strengthening customer focus remains a high priority for the Company in serving customers and responding to their new and evolving requirements while controlling costs and maintaining system safety and reliability. In the past number of years, customer growth and overall demand for natural gas has declined, influenced by competitiveness of natural gas to alternative energy sources and the challenge of the higher upfront capital and installation costs for natural gas. Furthermore, the evolving market environment characterized by the growth of alternative "green" technology, government policy changes affecting minimum appliance and building efficiency standards, and the introduction of the carbon tax imposes more challenges for the Company. Despite this environment, the Company continued to add new customers, maintain or increase the customer satisfaction levels, and enhance customer service activities.

Recent customer focused enhancement initiatives included the successful completion of the Customer Care Enhancement Project (CCE Project). The FEU successfully completed the stabilization phase of the CCE Project in the second quarter of 2012. The CCE Project was delivered on-time and under budget and successfully transitioned to an internally-delivered customer service operation, going live as planned on January 1, 2012. Final project costs were $109 million as compared to a budget of $115 million, a significant savings achieved while still meeting the timeline and project deliverables.

During the first year of operations, the FEU were able to deliver on customer service level commitments and make improvements to services while achieving cost savings over and above what was committed to in the FEU's 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (2012-2013 RRA). These cost efficiencies have been built into the Customer Service department O&M and therefore will be sustained for the benefit of customers into the future. The operational efficiencies gained and the solid performance during the first year of operations sets the foundation for further improvements over the next several years.

The Company is also continuing its efforts to add more customers to the system by working directly with key influencers like builders and developers, architects and engineers and promoting the benefits of using natural gas more broadly in the marketplace. Recently, there are encouraging signs of the success of these activities as the declining customer growth trend may be flattening. For new housing construction, the Company's overall capture rate (i.e. new homes with natural gas) appears to have stabilized. At the end of 2012, the Company's capture rate was 67 percent of new housing completions, up from 61 percent in 2011.

In addition to new housing, there is renewed interest from residential and small commercial customers to convert from oil and propane to natural gas. As a result of the Company's campaign to identify and market to homes using oil and propane, conversions were 4 percent higher in 2012 compared to 2011.

For industrial customers, the Energy Solutions team is working with large volume customers to understand and find solutions to meet their energy needs. With a stabilizing economy and low natural gas prices, load growth is being experienced from industrial customers in the mining, lumber, greenhouse and manufacturing sectors. From 2011 to 2012, total industrial volumes increased from approximately 58 petajoules to 60 petajoules. Similar to customer growth, adding more economic industrial load to the system will help to maintain the competitiveness of rates for customers.

To meet customers' growing demand for alternate uses of natural gas, the Company has been developing the natural gas for transportation (NGT) and liquefied natural gas (LNG) markets and also supporting customer demand for renewable natural gas (RNG). Added load from these markets will help maintain the competitiveness of rates by increasing throughput on the gas delivery system. Similarly, on the industrial front, FEI has received interest in the development of new major industrial facilities that use natural gas as a feedstock. The Company is engaging these customers to explore the opportunities and benefits that could be achieved for the benefit of ratepayers if we were to deliver natural gas for them.

The Company will continue its efforts to enhance service delivery performance by building on recent achievements and operational enhancements. A priority will be to improve first contact resolution by identifying and eliminating major drivers for repeat calls, which will positively impact customer satisfaction. To help maintain the competitiveness of natural gas rates for customers, FEI will focus on growing its customer base and the load on the natural gas system by developing new markets for natural gas use, attracting new customers and retaining existing customers. The following sections provide more details about the initiatives that the Company has undertaken and is continuing to pursue.

4.3 *CUSTOMER SERVICE INITIATIVES*

During the first year of operations of the in-sourced customer service functions, the following improvements have led to an increased focus on the customer and first contact resolution:

- Ability to receive and react quickly to customer feedback;
- More integration with and support from the rest of the organization;
- More choices for customers on how they interact with FEI; and
- Better understanding of customer needs and trends related to customer service through metrics and reporting.

The Customer Service group regularly receives direct feedback from customers and uses this feedback to improve its processes. Recent examples of these types of improvements include changes to the meter exchange and collections processes which resulted in operational efficiencies and improved customer satisfaction and the switch to monthly meter reading which reduces estimated bills, a significant source of customer dissatisfaction in the past.

There are significant benefits from having billing staff in close proximity to call center representatives. More complex billing inquiries are escalated to the billing area where analysts have a greater depth of utility and client specific knowledge. This has resulted in more timely resolution of complex billing issues and rapid response to escalated complaints. The knowledge transfer between billing and call center staff results in quicker identification of potential billing issues based on customer service representative or customer feedback, leading to a higher quality of service to customers.

The proximity of the Customer Service group to other departments in the organization also supports an enhanced customer experience. Feedback from the Customer Service group creates an improved understanding of customer communication when developing bill messaging. Improved communications between departments has also resulted in faster resolution of new construction and meter installation inquiries.

Customer Service staff from both billing and the call centers have also benefited from the knowledge transfer with the field staff. Field technicians have provided ‘ride-along’ opportunities for office staff, creating a greater understanding between the groups. Similarly, field employees have the opportunity to listen to live calls in the call center, gaining knowledge of how the call center interaction affects the customer experience. A high bill initiative saw billing and call center managers visit various locations throughout the service territory to build a greater understanding of the customer experience with high bill inquiries.

Enhancements to interactive voice response (IVR) and account online provide increased choices for customers in how they interact with FEI. The enhancements include a call back feature and ability to enroll in the Equal Payment Plan and inquire and create payments, allowing the customer better access to information during off-contact hours, and routine transactions to be completed more efficiently. In the future, self-serve options through IVR and account online will continue to be added.

Overall, 2012 was a successful first year of operations and sets the foundation for further improvements and efficiencies over the next few years.

4.4 *CUSTOMER RETENTION AND GROWTH INITIATIVES*

The Company is faced with slow customer addition growth and a decline in average use per customer despite low gas commodity rates in recent years. Although the decline in gas commodity rates has improved the price competitiveness of natural gas against electricity on an operating cost basis, this decline has been offset by increases in carbon tax along with higher capital and installation costs for natural gas equipment versus those of electric equipment. Additionally, residential customers do not generally understand the price differentials between differing fuel sources. Furthermore, the role of natural gas in its traditional use of space and water heating, which makes up over 80 per cent of residential natural gas throughput, continues to be challenged by changing environmental policies, energy policies and regulations. These declining trends negatively impact throughput and load growth. Steps need to be taken to mitigate these pressures.

4.4.1 Customer Retention

FEI will continue to focus its efforts on customer retention with a proactive approach to addressing customer concerns before they make the decision to leave the gas distribution system. This includes understanding customer attrition and the causes, through the identification of the factors that are predictors of customer loss and also understanding which customer segments are at flight risk. By better understanding these factors, FEI can implement initiatives to create a competitive differentiation through customer experience and through building loyalty with customers through a continued focus on customer satisfaction.

FEI continues to improve customer engagement through education and awareness of the benefits of natural gas use along with providing customers with energy management tools and energy efficiency programs facilitated through multiple communication channels. With ongoing analysis and information gathered during the PBR period, FEI will adapt its strategy for customer retention to ensure that such efforts are realized.

4.4.2 Customer Growth

Addressing the customer growth challenges requires an approach that attracts customers by increasing preferences for natural gas use with a focus on efficient use of energy and continuing the Company's sales efforts to enhance relationships with the builder and developer community.

FEI is currently reviewing its customer growth strategy with a view to increasing the penetration rates of end-use gas appliances in the home and to promote gas use for cooking. This strategy will serve to both add new customers, as well as aid in the retention of the customer once added to the system, as customers with a greater number of gas-end use appliances are more likely to remain connected to the gas delivery system.

Customer growth will continue to be facilitated through enhancement of FEI's high carbon fuel switching program which provides incentives to customers to switch from higher carbon to lower carbon-emitting fuels, through the installation of high efficient ENERGY STAR® heating systems. The program adds value to new and existing customers by reducing their fuel costs, increasing natural gas throughput, minimizing environmental hazards associated with oil storage tanks, decreasing the need to import propane and heating oil fuel from other provinces, and improving air quality.

The Company continues to review its sales channel network approach. Small builder and developers groups now make up a large proportion of the new meter requests where historically large builder and developers groups initiated new meter and service line requests. This shift requires an alignment of the sales method as builder and developer groups have a significant influence on gas use in new homes. Additionally, the sales group is continuing to explore innovative ways to engage this wider network of builders and developers along with other influencers of gas use in new homes, including architects, engineers, contractors, manufacturers, dealers as well as homeowners. In addition FEI will explore the role that incentives to add gas appliances may play in the decision making process through these additional sales channels.

5. ORGANIZATIONAL PERFORMANCE AND MONITORING

5.1 *BALANCED SCORECARD*

The FEU use a Balanced Scorecard approach to deliver on a number of key success measures critical to the business. The performance assessment is integral for management in evaluating performance and in determining cost-effective service levels for customers going forward.

Starting in 2012, changes to the FEU's scorecard were made to standardize the scorecard categories between the Gas and Electric businesses. The number of measures was reduced from 10 to six with two new measures added: All Injury Frequency Rate and Public Contacts with Pipelines.

The FEU's Scorecard is currently comprised of four categories of measures with six measures in total that describe and guide the Companies' overall performance in meeting the targets that are set annually. The scorecard serves as a valuable communication tool used to describe in clear and objective terms success measures for the Utilities. The four categories of measures include Financial, Safety, Customer and Regulatory and are described below.

5.2 *FINANCIAL*

Net earnings for the FEU is used as the financial performance measure taking into account earnings from revenues, operating and maintenance expenses, depreciation, amortization, property taxes, interest expense and income taxes. It incorporates the approved costs and revenues that are utilized in determining customers' rates each year.

5.3 *SAFETY*

Employee safety is of fundamental importance and is measured through the All Injury Frequency Rate (AIFR) which is the number of medical aids and lost time injuries per 200,000 work hours. Safety is also measured by the number of recordable vehicle accidents. The targets are set to encourage employee behaviours that all accidents are preventable and no accidents are acceptable.

5.4 *CUSTOMER*

The two measures related to the category Customer include Customer Satisfaction and Public Contacts with Pipelines. Customer Satisfaction as measured through an index score is designed to reflect feedback from residential and business customers on emergency and non-emergency services, billing and call centre services, natural gas products, communications and corporate image. Public Contacts with Pipelines reflects the number of line hits per 1,000 BC One Calls received. It measures the overall effectiveness of the public's awareness to minimize damage to FEI's natural gas system, which will reduce risk to public safety and service interruption to customers.

5.5 REGULATORY

Regulatory performance highlights the importance of achieving success on regulatory issues and agreements for the benefit of customers and the shareholder. The Company's overall objective is to submit effective, accurate and complete filings that result in efficient regulatory proceedings resulting in timely decisions to support the Company's management of the business.

Comparison of FEU's Scorecard to Peer Companies

The FEU's scorecard and the linkage to employee performance pay are consistent with that of other Canadian natural gas distribution utilities. This is indicated in the benchmarking survey completed by the FEU at the request of the Commission. On Page 127 of the 2012-2013 RRA Decision, the Commission directed

> *"The Commission Panel directs that for the next revenue requirements application, the FEU bring forward a benchmarking study that would assess their balanced scorecard against mechanisms used in other peer group companies and jurisdictions. Such an assessment should examine, among other things, the appropriate measurements for productivity and describe what a fulsome set of productivity measurements would entail. Additionally, the Commission Panel believes it would be useful for this study to examine how other members of the FEU's peer group link the use of their performance metrics with the assessment of corporate and individual performance."*

The request to bring forward a benchmarking study to assess the FEU's scorecard against that used by its peer companies and examine how other members of the FEU's peer group link the use of their performance metrics to performance is addressed in Appendix C2 – Scorecard Benchmarking Study. The study findings indicate that the FEU's scorecard is generally consistent with scorecards used by its peer group companies and incorporates comparable categories and performance metrics. Additionally, for the majority of companies surveyed, the scorecard results have some level of impact on corporate and/or individual performance, with scorecard results often used to determine employee's incentive compensation payments.

With regards to the part of the Commission's directive that FEU "should examine, among other things, the appropriate measurement for productivity and describe what fulsome of productivity measurements would entail", FEI undertook a review of productivity improvements in use and concludes that there is no consistent set of productivity measures in use in FEI's peer companies.

In its examination efforts for appropriate measurements of productivity, FEI as part of its Scorecard Benchmarking Study asked Canadian natural gas distribution utilities if there were metrics related to productivity on their scorecard. Of note for the responses received is the disparity in the productivity measures used by the respondents. Responses varied, with three respondents indicating there were no productivity metrics on their scorecard while two respondents indicated the use of O&M per customer. Other productivity metrics noted included the use competitive residential delivery rates and response to emergency calls as measures of productivity.

The disparity in responses on productivity metrics used was also noted in the Oliver Wyman report for Hydro One on measuring productivity[5]. As part of the study, a survey of US and Canadian utilities and regulators was conducted to assess how productivity measures were used. For the purpose of this survey, productivity was considered to be an activity-level metric such as “cost per pole” while service quality and cost were considered higher level metrics. For FEI, an example of a productivity measurement in use defined at the activity level is cost per interaction, discussed further in Section C3.5, or service line unit cost discussed further in Section C4.5.3.

The report noted that there “was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently. The reason for the disparity may have been because each utility was choosing metrics to track the success of different corporate goals.” In addition, it was noted in the report that “it is likely that most utilities are not measuring productivity across a large portion of their activities and total costs. The productivity metrics collected are generally not benchmarked, and none are regularly reported as [sic] to regulators.”

The inclusion of a productivity improvement factor in FEI’s PBR Plan provides a comprehensive productivity measurement that will require each department to consider continuous improvement, which is preferred to measurement of individual activity. Departments have a requirement to maintain or increase their outputs and activity levels while keeping cost increases below inflation on a per customer basis, which will result in a measured improvement in productivity. The result of this focus is evident and discussed in the departmental results and forecasts included in Section C3 of this Application and in the Productivity Focus and Organizational Performance discussion above that contains many actual examples of productivity achievements. FEI will continue to discuss productivity measures taken during the PBR Period at its Annual Reviews.

In support of this overall approach, the use of SQIs as a metric of performance ensures that productivity is being sought without any degradation of performance. Achieving productivity combined with maintaining service quality ensures that both customers and shareholder benefit.

[5] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20A/A-17-02.pdf

5.6 SUMMARY OF BALANCED SCORECARD

The FEU believe the Scorecard is an effective tool for improving organizational alignment and helping to focus the Companies' activities on key measures. The Scorecard remains an essential tool to measure the Companies' performance on key success measures important to customers, employees, the regulator, and the shareholder.

6. PROPOSED REGULATORY PROCESS

FEI proposes that this Application can be addressed efficiently and effectively through a Negotiated Settlement Process (NSP). FEI has discussed the proposed process with its customary intervener groups, and understands that they are not opposed to an NSP. FEI's proposed draft regulatory timetable presented below seeks to acknowledge the workload required by the Commission and all parties and which will promote an efficient regulatory process.

As noted above, FEI requests that the regulatory process used to establish the terms of the PBR include a negotiated settlement process. A review of recent academic literature on the success of negotiated settlements as a regulatory process for oil and gas utilities in Canada indicates that settlements have cut regulatory processing time, increased the duration of outcomes, and were generally used as a vehicle for rapid development of multi-year incentive agreements and light-handed regulation[6]. FEI believes that flexibility is needed in the regulatory process to address the varied interests of the participants and the array of risk-reward trade-offs implicit in possible PBR plan provisions. A negotiated settlement process provides the needed flexibility to address these issues in a dynamic way for both interveners and the utility.

To illustrate, various plan elements such as the productivity factor, earnings sharing arrangements, service quality indicators, exogenous factors, off-ramps and others are all, in effect, inter-related with each other in a PBR plan. A change in one of these elements may suggest or require changes in one or more of the other components to keep the plan in balance. An example of this is whether a PBR plan should include an ESM. A PBR plan with an ESM would most likely have a narrower range for a return on equity (ROE) off-ramp and perhaps no stretch factor component in the productivity improvement factor (or X-Factor). An otherwise similar PBR Plan without an ESM would likely have a wider range for an ROE off-ramp and possibly a larger X-Factor. The larger X-Factor acts as an upfront dividend for ratepayers, but the utility receives a larger reward for performing better than the target by not being required to share the earnings.

FEI believes that a negotiated settlement process provides an efficient way to discover the overall balance of interests and how changes in the plan elements are best reflected in adjustments to other plan elements. An oral hearing to establish a PBR is not conducive to the give and take between parties or accommodations by the utility or the customer groups to achieve a balanced result. With only a small number of utilities in British Columbia that might be regulated under a PBR, the use of negotiated settlement provides an opportunity to address the unique circumstances of each utility and, as has been proven with past PBRs, provides a practical and efficient means to establish a successful plan.

FEI's proposed draft regulatory timetable is set out below.

[6] Appendix D8-1: J. Doucet and S. Littlechild "Negotiated Settlements and the National Energy Board in Canada" (2009) Energy Policy 37(11): 4633-4644.

ACTION	DATE (2013)
Workshop	June 19
Commission Information Request No. 1 to FEI	July 8
Intervener Information Request No. 1 to FEI	July 15
FEI Response to Information Requests No. 1	August 15
Commission Information Request No. 2 to FEI	August 30
Intervener Information Request No. 2 to FEI	August 30
FEI Response to Information Requests No. 2	September 20
Negotiated Settlement Process or Hearing if Required (proposed date range)	October 1 to October 21
FEI Final Argument Submissions (if required)	November 1
Intervener Final Argument Submissions (if required)	November 8
FEI Reply Argument Submissions (if required)	November 15
Anticipated Decision	December 4

FEI is optimistic that the proposed regulatory timetable will allow for a Commission determination on rates in time to have permanent rates effective January 1, 2014. FEI will seek approval of rates, on an interim basis effective January 1, 2014, should it become apparent that a Commission decision may not be received before year end.

7. ORGANIZATION OF THE APPLICATION

This Application provides detailed information in support of the Company's proposed PBR Plan. The remainder of the Application is organized as follows:

- Section B is a description of the PBR Plan, providing a discussion of the history of PBR at FEI, a comparison to PBR in other jurisdictions, and a summary of all of the key PBR Plan elements;
- Section C sets out the Company's forecasts for the PBR Period as follows:
  - Section C1: Forecast demand for natural gas and resulting revenues and margin at existing rates;
  - Section C2: Forecast of other revenue;
  - Section C3: Historical and forecast O&M with supporting departmental summaries and drivers; and
  - Section C4: Historical and forecast capital expenditures by major capital category;
- Section D discusses the Company's accounting, finance and tax issues:
  - Section D1: Financing and Return on Equity;
  - Section D2: Taxes;
  - Section D3: Accounting Policies; and
  - Section D4: Deferrals; and
- Section E provides the financial schedules filed in support of the 2014 delivery rates proposed in this Application.

Each section of the Application is also supported by a set of Appendices, including expert reports where applicable.

B: *MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM*

1. INTRODUCTION

This section of the Application sets out FEI's proposal for a Performance-Based Ratemaking plan for a five-year period commencing in 2014 (the PBR Plan or the 2014 Plan), and provides other background information with respect to PBR. The material in this section, along with information contained in Appendices D1 through D9, provides FEI's response to the Commission letter dated April 18, 2013, which requested that the FortisBC Energy Utilities and FortisBC Inc. include a PBR proposal with their next revenue requirements application and provide a review and comparison of PBR regimes in effect in other jurisdictions with the proposed PBR plan.

FEI has had two successful PBR plans in the past (1998-2001 and 2004-2009) that further aligned the interests of customers and the Company. In FEI's 2012-2013 RRA the Commission examined the results of FEI's 2004-2009 PBR plan (the 2004 PBR Plan) and concluded that significant benefits were achieved for both ratepayers and shareholders:

> *"In British Columbia, PBR, combined with the Negotiated Settlement Process has played a role within the rate setting process of FEI. Starting in 2004 and lasting through 2009 FEI operated in a PBR environment. During this period FEI was very successful as targets were met and the Companies note that shared earnings benefits flowing to customers and shareholders totalled $67.5 million each over the six years.*
>
> *The Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements."*[7]
>
> *"As noted in section 4.2, the Commission recognizes that during the PBR period FEI was able to find significant cost savings to the benefit of customers and the shareholder. During this six-year period $67.5 million in benefits flowed to customers, while an equal amount flowed to the shareholder."*[8]

The proposed 2014–2018 PBR Plan builds on FEI's successful 2004–2009 PBR Plan. The new PBR Plan focuses the performance incentives on the main areas of controllable costs, operating and maintenance (O&M) expenses and capital expenditures, consistent with the 2004 PBR Plan. The formulas to be applied to O&M and capital expenditures over the PBR term have the

[7] Commission Order G-44-12, Reasons for Decision, page 22
[8] Commission Order G-44-12, Reasons for Decision, page 34

same structure as in the 2004 PBR Plan, and employ the same or similar cost drivers, an inflation factor and a productivity improvement factor; however, some refinements to the formula parameters are proposed.

The success of FEI's 2004 PBR Plan provides a strong basis for going forward with a similar model for the proposed PBR. The model approved for use by FEI between 2004 and 2009 provided a flexible framework of incentives that allowed FEI to capture efficiencies for the long-term benefit of customers. Although the opportunities and potential results may be different in 2014 to 2018 than they were in 2004 to 2009, the Commission should have confidence that the incentive framework in the proposed PBR Plan will lead to a similar response from FEI this time.

FEI's PBR experts, B&V, have studied the available PBR methodologies and provided their recommendations on FEI's proposed PBR Plan model in Appendix D1 Comparison of Recent Performance Based Regulation for Distribution Utilities in Canada (the PBR Report). They conclude that there is no one "right" PBR model, and that the framework adopted for FEI should be in keeping with FEI's specific circumstances. B&V also identified some theoretical and practical issues with aspects of the plans developed in other jurisdictions that do not exist with the model being proposed by FEI. FEI's proposed PBR incorporates a more aggressive "stretch" productivity factor than is suggested by B&V's research of other North American utilities. (B&V Total Factor Productivity (TFP) for Gas Utilities Report – referred to as "TFP Report" or TFP Study", Appendix D2) FEI's model produces lower rate increases over the five year period than either cost of service regulation or a revenue cap model of the type approved by the Alberta Utilities Commission.

Overall, FEI believes that the proposed PBR Plan is an appropriate model that will encourage FEI to seek efficiencies in its operations over the term of the PBR for the benefit of both customers and the Company, while maintaining safe, reliable and customer-oriented utility service. B&V, who have provided input in the preparation of both the PBR Plan and this chapter of the Application,[9] endorses the overall proposed PBR Plan as being reasonable in the circumstances of FEI, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regard the appropriate productivity factor as being approximately zero, based on the TFP study they conducted and the specific elements of the proposed PBR Plan. In other words, FEI's proposal is more favourable to customers than they would recommend. FEI is nonetheless comfortable with the proposal as part of an overall package.

The section is organized as follows:

- Section B2 – PBR Overview – discusses the effectiveness of PBR, its benefits and challenges;

[9] B&V has provided input in the preparation of this chapter of the Application, and has also contributed sections providing their commentary on certain elements of the proposed PBR Plan. FEI has endeavoured to expressly attribute the portions that reflect B&V's commentary.

- Section B3 – PBR Variations – discussion of price cap and revenue cap variations on the PBR model;
- Section B4 – FEI Experience with PBR - a historical review of FEI's prior PBR plans;
- Section B5 – Jurisdictional Comparison – a review of the most recent PBR plans employed in Canada;
- Section B6 – FEI 2014 Proposed PBR - a full description of the proposed PBR for 2014-2018;
- Section B7 – Delivery Revenue Forecasts Under PBR - a comparison of customer delivery rates under the proposed PBR with rates under a cost of service regulatory approach and under a revenue cap model; and
- Section B8 – Conclusion.

2. PBR OVERVIEW

This section, which was prepared with input from B&V, addresses the benefits and challenges of PBR. PBR can provide additional incentives to the utility beyond those incentives inherent in cost of service regulation to undertake additional steps to reduce costs. The mechanism thus further aligns the interests of both customers and the utility shareholder. The concerns typically cited regarding PBR are, in some cases, overstated. In other cases, the concerns can be addressed by appropriate PBR design.

2.1 *PBR BENEFITS*

The two most commonly cited benefits of a PBR plan are its effectiveness in incenting the utility to capture efficiencies, and regulatory efficiency.

A PBR plan (also known as incentive regulation) uses a formula-based approach to adjust the prices or rates during the PBR term and decouples the utility's revenues and earnings from its costs. This approach encourages the regulated utility to adopt proactive efficiency plans that reduce costs. Customers also benefit from these efficiency plans, as an indexing formula ensures that the anticipated productivity gains, such as those expected on an industry wide basis, are provided to customers through lower rates. In other words, pure PBR regulation operates more like a fixed price contract in the sense that for a pre-specified period, the utility cannot pass on its additional controllable costs[10] to customers and takes on most of the risk for these costs. PBR can also improve the dynamic efficiency of the utility if the PBR term is long enough to encourage the cost-reducing innovations and investments that bring long-term efficiency gains.

PBR provides a longer term framework in which the utility can operate without frequent, costly and time consuming revenue requirement applications. Hence, a PBR mechanism can decrease the amount of regulatory process required for rate setting, particularly for utilities with regular cost of service rate cases, such as FEI's RRAs in 2010-2011 and 2012-2013. However, the extent of regulatory efficiencies achieved depends, for instance, on the frequency and scope of the review process adopted as a component of the PBR plan. As discussed later, FEI's proposed PBR Plan seeks to balance the anticipated desire on the part of some stakeholders for periodic review with the objective of capturing regulatory efficiency.

2.2 *POTENTIAL PBR CHALLENGES*

The arguments typically raised in opposition to PBR relate to the potential for "windfall" profits or losses for the regulated utility or customers, service issues, and challenges relating to the timing of capital expenditures. These challenges are discussed below. B&V concurs that the

[10] The utility can only pass on the costs implicit in the PBR formulas that determine the rate adjustments. If the PBR includes an earnings sharing mechanism some additional costs or cost savings may be passed on indirectly.

challenges can be managed through the design of a PBR Plan, and that there are provisions in FEI's proposed PBR Plan that appropriately address these challenges.

B&V observe that the potential for the utility to achieve higher earnings is inherent in a PBR and is one of the key reasons why it works. The issue is typically one of degree, with the potential for very significant losses or gains to be perceived by some stakeholders as being contrary to the "just and reasonable" rate principle. B&V also addresses this issue, for instance, in its TFP Report (refer to Appendix D2, page 7), stating:

> *"The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level. Customers actually benefit even in the absence of an earnings sharing mechanism by a reset of the cost basis of rates at the start of a new regulatory control period as the efficiency gains become entrenched in the utility's revenue requirements on a going forward basis."*

Earnings sharing mechanisms and mechanisms that allow the utility or customer to re-open the PBR (sometimes referred to as "re-opener" provisions) can be incorporated into the design of an overall PBR plan to temper the potential for profits or losses for the regulated utility.

A concern under PBR is that efficiencies not be achieved at the expense of service quality. B&V observe that, for this reason, PBR plans typically include provisions relating to service quality. FEI's 2004 PBR Plan, for instance, included a variety of Service Quality Indicators that FEI was required to report on in the Annual Reviews. Service Quality Indicators (SQIs) are proposed in the current FEI proposal as well.

B&V identify capital investment lumpiness in the utility industry as being another industry-specific problem for pure formula-based PBR plans. The formula's cost drivers used to forecast the capital investments may not be able to capture all of the significant, inconsistent and unusual investments that are common in the utility industry. The current recognition across many jurisdictions that much of the existing utility infrastructure is ageing and in need of replacement or major refurbishment is an example of a capital investment issue that formula-based PBR models may not adequately capture. B&V observe that it is particularly important to recognize that infrastructure replacement programs have significant and negative impacts on productivity and thus change the dynamics of the price or revenue cap requirements (this impact of infrastructure replacement on productivity is the subject of considerable discussion in B&V's TFP Report). This legitimate concern is ordinarily dealt with through the use of special cost recovery mechanisms that fund certain capital expenditures outside the PBR formula and within separate regulatory proceedings[11]. These are sometimes referred to as "capital trackers", a concept akin to excluding CPCN projects from the operation of the PBR formula.

Concerns are sometimes expressed that a utility under PBR may defer capital or O&M costs to outside the PBR term, or adopt other cost shifting strategies that do not produce true efficiency gains in order to obtain benefits under the PBR. These issues are not a function of PBR; rather, they relate to how the utility manages its costs within a defined rate setting period that could be either PBR or a forward test year under cost of service ratemaking. Nevertheless, FEI has addressed these concerns in Appendix D4, as some customer groups raised a concern that they perceived FEI had deferred expenditures to outside the 2004 PBR Plan period in a way that was detrimental to customer interests. In summary, FEI has shown in Appendix D4 that cost deferrals were very minor, and that deferrals of capital tend to produce a positive net present value in any event. Appendix D4 also explains how proposed changes in this PBR Plan should eliminate or minimize any further concern in this area.

In practice, the majority of PBR models are of a hybrid form, reflecting elements of both PBR and cost of service and regulators use various policy tools to overcome the above mentioned challenges.

[11] According to American Gas Association report (June 2012), 47 utilities in 22 states serving 24 million residential natural gas customers are using full or limited special rate mechanisms to recover their infrastructure investments.

3. PBR VARIATIONS

The most common PBR approaches use formulas that employ an inflator and a productivity offset factor (referred to as (I – X) mechanisms). These approaches fall into two broad categories: price caps and revenue caps. The technical discussion below was prepared in consultation with B&V.

Under a price cap formula, the current prices or rates are a function of the previous year's rates, inflation (the "I factor") and an efficiency factor (known as the "X-Factor") where current rates are determined by adjusting the previous year's rates based on the difference between the inflation and efficiency factors:

$$P_{t,m} = P_{t-1,m} * (1+ (I-X)) +/- Z$$

Where: $P_{t,m}$ *= rates for customer class m in time t*
I = inflation factor
X = efficiency factor
Z = adjustments for unforeseen events beyond management's control

Under a revenue cap approach, the company's authorized revenue is subject to a cap. The cap might fix the base-rate revenues or it might allow some adjustments for increases in direct proportion to a growth adjustment factor (usually the number of customers). A variant of this approach is a revenue per customer cap, where the growth adjustment factor includes average revenues per customer and annual change in number of customers.

The revenue cap formula is similar to price cap; however, instead of customer rates, it is the allowed revenue which is adjusted by the (I – X) formula and is presented as:

$$R_t = (R_{t-1} + RGAF) * (1+ (I-X)) +/- Z$$

Where: R_t *= allowed revenues for in time t*
RGAF = revenue growth adjustment factor
I = inflation factor
X = efficiency factor
Z = adjustments for unforeseen events beyond management's control

Both cap approaches create incentives to reduce costs and increase efficiency. However, there is a significant difference between price cap and revenue cap models in terms of the way they treat energy demand and incremental sales volumes. In the price cap model, a utility bears the risk for demand variations and is encouraged to maximize sales volumes up to the point where marginal revenue is equal to marginal costs. This is beneficial to utilities with a stable and growing demand trend. Demand variations can be problematic and unfair under a price cap model for utilities where, due to exogenous factors, there is a continuing decline in sales per customer (such as the case with current and forecast trend in natural gas use rates in BC). On the other hand, similar to revenue-decoupling mechanisms used for demand-side management regulation, the revenue cap model decouples the allowed revenue from demand and protects the utility against possible demand variations.

PBR plans (both price cap and revenue cap) are typically further categorized into two subgroups based on their rate base assessment methodology and the role of (I–X) mechanism in forecasting their costs. These are termed the "building-block" approach and the "total expenditure" approach.

Under a building-block approach, the O&M expenditures (Opex) and capital expenditures (Capex) are assessed separately, and in some cases the Capex expenditures are treated outside the (I – X) mechanism and the efficiency factor is only applied to the Opex. Under the total expenditure approach (also known as Totex), Opex and Capex are summed up and regulated under one efficiency factor (ordinarily total factor productivity). Totex and the building-block approaches lead to equal results if the productivity improvement factor and the expenditures covered under the formula are the same, other things being equal. However, due to the lumpy nature of utilities' forecast investments, the majority of PBR plans end up as hybrid systems where a part of the capital expenditures (such as significant sustainment capital) is treated outside the PBR formulas and the rest of capital expenditures and O&M expenditures are determined under the indexing formula and the productivity factor. By removing sustainment capital from the formula, the large negative impact on TFP from infrastructure replacement is reduced or even eliminated resulting in a TFP that would otherwise be negative moving closer to zero.

PBR design is an exercise in balancing utility flexibility to seek out efficiencies and the need for a regulatory review process that ensures just and reasonable rates and the safe and reliable provision of services to customers. B&V's view is that there is no single "correct" type of PBR design, and pure revenue and price cap PBR designs are unlikely to be practical. FEI's proposed PBR plan, discussed later in this chapter, is a building block model within the revenue cap category. It has been designed with reference to past experience and the particular context relevant to the utility. B&V endorses the proposed PBR Plan, with the caveat regarding the proposed productivity factor should be closer to zero rather than FEI's more challenging and aggressive proposal of 0.5 percent.

4. FEI EXPERIENCE WITH PBR

The Commission letter dated April 18, 2013, titled "Productivity Improvements in a Performance Based Rate Setting Environment" requested that FEI's examination of PBR methodologies include discussion of the most recent PBR plans employed by FEI. FEI has had two successful PBR plans in the past (1998-2001 and 2004-2009). FEI's proposed PBR Plan builds on that success, incorporating a number of similar elements, with adjustments where appropriate. This section outlines FEI's past PBR plans. Further discussion regarding FEI's most recent PBR Plan is included in B&V's PBR Report (Appendix D1).

4.1 *FEI PRE-2004 PBR EXPERIENCE*

A formula-based approach to setting O&M was first adopted in FEI's 1994-1995 settlement and refined in the 1996-1997 settlement. The PBR plan originally approved for 1998-2000, subsequently extended to 2001, was a further step forward. In comparison to the alternative of annual revenue requirement filings, the longer term focus better enabled the Company to invest in efficiency initiatives with multi-year paybacks; there was time to realize incentive gains before the multi-year term ended. During the 1998-2001 PBR, the Company undertook restructuring, and the break-even point on this restructuring "investment" was achieved by the fourth year. In addition to a focus on pursuing operating and maintenance cost efficiencies, the 1998-2001 PBR plan included a limited capital incentive mechanism and a series of SQIs that were tracked to confirm that service quality was being maintained throughout the term.

4.2 *FEI 2004 PBR EXPERIENCE*

FEI's next PBR plan, which is the subject of this section, commenced in 2004 pursuant to an approved Negotiated Settlement Agreement and remained in effect (after an approved two-year extension) until 2009. It was based on the previous PBR Plan in key aspects. For instance, base O&M expenses and capital expenditures were escalated by a formula that incorporated forecast inflation and productivity factors. It included a 50/50 earnings sharing mechanism between customers and shareholders, and retained most of the same deferral accounts and exogenous factors as the 1998 PBR. The 2004 PBR Plan did however incorporate some enhancements over the prior plan, including (i) a longer term, (ii) a stronger capital incentive, (iii) service quality indicators that were more results oriented, and (iv) a proposed Efficiency Carry-over Mechanism (ECM) designed to encourage the Company to continue to pursue efficiency gains throughout the PBR term. Approved components of the 2004 PBR Plan remain appropriate for the 2014 Plan, with some enhancements.

Term

FEI proposed a five year term for the 2004 PBR Plan, from 2004 to 2008. A four-year term from 2004 to 2007 was approved, and later extended for two years, ending in 2009.

O&M Expenses

The approved 2003 O&M was used as the base, and then escalated by inflation, a productivity factor and a customer growth factor. Customer growth was expressed as the change in the average number of customers from one year to the next. Although O&M was not rebased to actual spending levels during the PBR term, there was a provision to true-up the formula amounts going forward based on actual customer growth. Pension and insurance costs were forecast each year, with the variance deferred for flow-through amortization.

Capital Expenditures

Similar to O&M, the capital expenditures approved in the 2003 RRA were used as the base, and then escalated for inflation and a productivity factor. Each year, the capital expenditure forecasts were developed using the customer additions forecast for growth capital and the forecast average number of customers for all other base capital. The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer growth.

CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes.

Inflation Rate

An average annual forecast inflation rate was determined based on the following sources for BC Consumer Price Index (CPI):

- Conference Board of Canada
- BC Ministry of Finance
- RBC Financial Group
- Toronto-Dominion Bank

During the Annual Review, an updated inflation forecast for the upcoming year was provided.

Productivity Factor

The parties involved in the NSP agreed that linking the productivity factor to BC-CPI would be beneficial for both ratepayers and FEI since the productivity opportunities would increase as inflation increased, and conversely FEI would have more limited opportunities for productivity improvements if the rate of inflation decreased. The productivity factor agreed to was 50 percent of CPI for 2004 and 2005, and 66 percent of CPI from 2006 to 2009.

Customer Growth

Each year at the Annual Review, an update of the actual number of customers at the start of the year as well as a revised forecast for customer additions for the upcoming year was provided.

Earnings Sharing Mechanism

The variance between the allowed and actual return on equity was shared equally between customers and shareholders. Over the term of the PBR, customers and shareholders each received a benefit of $67.5 million, indicating that the PBR successfully reduced costs and resulted in material savings.

Service Quality Indicators

FEI established a number of SQIs to ensure that the Company continued to maintain a high level of service quality, and that cost reductions did not come at the expense of service and system standards. Each year, FEI's SQI results were compared to the established benchmarks and presented at the Annual Review. FEI consistently performed within the range for the SQIs.

Efficiency Carry-Over Mechanism (ECM)

FEI had proposed an ECM, referred to as the Full Term Efficiency Incentive. The proposed ECM was designed to provide incentives for the company to pursue efficiencies throughout the PBR term, even in the later years when the time remaining to generate benefits was limited. FEI's proposal incorporated a rolling five year period over which to recover the initial investment and generate further benefits.

The 2004 NSP resulted in a variation of the proposed ECM which was a phase-out of capital benefits only. It involved determining the difference between the formulaic and actual capital expenditures over the term of the PBR, and then, rather than full rebasing right away, the Company received 2/3 of its 50 percent share in the first year following the expiry of the plan, and 1/3 of its 50 percent share in the next year. The net benefit of the ECM in the 2004 PBR Plan was approximately $11 million, resulting in significant benefits for both customers and shareholders.

The rate base benefit factor was a factor to be applied to the capital expenditures savings to determine the amounts for the end-of-term phase-out. The agreed upon factor of 14 percent was representative of the average avoided revenue requirement (expressed as a percentage) related to capital expenditures being below the formula amounts.

Annual and Mid-Term Assessment Review

At its Annual Reviews, FEI presented its actual results from the previous year, projections for the current year and updated forecasts for the coming year. The Annual Reviews informed parties of past performance and also kept them apprised of any potential challenges facing the Company in the future.

The Mid-Term Assessment Review was held prior to the end of the third year of the 2004 PBR Plan, or 2006. The purpose of the review was to ensure that the PBR did not result in unintended outcomes, or lead to a deterioration in FEI's quality of service.

Results

As noted above, the Commission acknowledged that the 2004 PBR Plan was successful in achieving significant savings and benefits for both customers and the Company. These benefits were achieved in three ways – through the productivity improvement factor, through the O&M savings, and through the capital savings. Each of these is discussed below.

PRODUCTIVITY IMPROVEMENT FACTOR

In total the productivity improvement requirements over the six year period represented a 7.5 percent decrease in gross O&M or a cumulative benefit of approximately $45 million over the PBR term. This was a material benefit to customers even before any incremental earnings above the approved ROE could be achieved and shared. It was only with major restructuring that produced material sustainable savings that FEI was able to meet and exceed these targets. This was primarily the Utilities Strategy Project in 2003 and 2004 which brought FEI and FEVI under common management and produced lasting efficiencies for both utilities. The lasting benefit to customers from these efficiencies was that FEI had a lower O&M as the base level to move into the cost of service period, the 2010-2011 RRA that followed.

In addition, the efficiencies attained during the six year PBR period (both to meet and exceed the productivity improvement targets) were achieved without degradation in the quality of service provided to natural gas customers. FEI consistently performed within the range for the SQIs throughout the term. FEI also met other requirements in the PBR to be open and transparent in conducting its business. This included conducting Annual Reviews and Customer Advisory Council meetings as set out in the PBR, and responding to the issues and concerns raised by customers and Interveners in those settings.

O&M SAVINGS

During the PBR period, FEI found efficiencies to meet the productivity improvement requirements in the PBR formula and exceed the O&M targets by an aggregate amount of $87 million over the six years. Customers received 50 percent of this or $43.5 million back via the earnings sharing mechanism. O&M savings during the PBR Period benefit customers in two ways:

1. Through reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Through rebasing of the savings into opening O&M as the starting point for setting future rates after the PBR has ended.

CAPITAL SAVINGS

There were significant capital savings achieved over the term of the PBR period. Capital savings over the PBR period benefits customers in two ways:

1. Through reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Through rebasing of the savings in the opening rate base and future rates after the PBR has ended.

During the 2004 PBR, FEI's actual base capital expenditures for the six-year period were $490.2 million. This was $80.1 million, or about 14 percent on average, below the formula-allowed capital expenditures of $570.3 million for the period. The year-to-year amounts of the formula-based and actual capital expenditures are provided in Attachment 2 to Appendix D4 which is a copy of Exhibit B1-48 from the 2012 Generic Cost of Capital proceeding. FEI's actual capital spending was under the formula-based number in each year except 2009 where the actual spending was approximately $1 million above the formula-based amount.

The capital spending reductions relative to the formula-based spending allowances generated earnings benefits throughout the PBR term that were shared with customers through the earnings sharing mechanism. These earnings differences pertained to the differences in rate base return, depreciation expense and taxes between the formula-based plant balances and the plant balances from the actual expenditures. The earnings differences grew from year to year as FEI continued to contain its capital spending below formula allowed levels. The aggregate benefit over the six years that arose from these capital efficiencies was in the range of $50 million and customers received half of this back through the earnings sharing mechanism.

The second benefit to customers was that the opening rate base going into the next revenue requirement application was lower by approximately $80 million (less the corresponding accumulated depreciation on the $80 million during the PBR period). This rate base reduction produces sustained revenue requirement reductions in the order of $10 to $12 million per year.

A detailed description of PBR components for FEI's approved 2004 PBR Plan is included in the PBR Commission Decisions in Appendix D9. Continuing with that evolutionary approach, key elements of the 2004 PBR Plan are incorporated into the proposed Plan.

5. JURISDICTIONAL COMPARISON

The Commission letter dated April 18, 2013 requested that FEI's evaluation include the most recent PBR plans employed by FortisBC Inc. and PBR methodologies approved by other jurisdictions in Canada. B&V was retained to assist FEI in compiling and consolidating the information requested by the Commission and to provide its own expert assessment as to the merits of other PBR plans. In this section, FEI summarizes the elements of PBR plans employed in other Canadian jurisdictions. B&V's report, which is included in Appendix D1 to this section, contains further analysis. FEI's proposed PBR Plan shares many common features with other plans, with the overall package tailored to fit the circumstances of a BC utility with past experience in PBR.

In the last decade, various Canadian regulators (at provincial and federal levels) have employed PBR plans in the regulation of public utilities and pipeline companies within their jurisdiction. Currently, Alberta and Ontario are the only jurisdictions with PBR plans for major local distribution companies. Gaz Metro, a Quebec utility, recently emerged from PBR. FEI has provided information in this section about PBR plans from all three jurisdictions. B&V was asked to focus its analysis on the current plans (i.e. those in place in Ontario and Alberta), and the past plans from BC. In addition to being the most current, Alberta and Ontario are the largest jurisdictions in terms of the number of utilities and the background information required for B&V's assessment is readily available in English.

A summary of PBR plans applied to natural gas and electric utilities in these three jurisdictions is presented in the table below.

1 **Table B5-1: Jurisdictional Comparison**

	Alberta Electricity and Natural Gas	Union Gas (2008-2012)	Enbridge Gas (2008-2012)	OEB 4th Generation IR (Electricity)[12]	Gaz Metro (2007-2012)
Regulatory proceedings	Multi-utility oral hearing, AUC's initiative	Negotiated settlement	Negotiated Settlement	Multi utility hearing, OEB's initiative	Negotiated Settlement
Type	Revenue per customer (NG) and price cap (Power)	Hybrid Price cap (Cap adjusted based on Average Use)	Revenue per customer	Price cap	Hybrid (Cost of service, revenue cap and price cap)
Term	5 years				
Coverage	Includes both O&M expenditures and Capital expenditures				
Inflation	Composite (AWE,CPI)	GDP IPI FDD[13]	GDP IPI FDD	Composite index	Quebec CPI
X-factor methodology	TFP study	Negotiated. Not based on any specific report.	Different percentage of inflation	TFP Study	Negotiated. Reflective of the historical rate increases and inflation
Stretch-factor	0.2%	Implicit in the X-Factor	Implicit in the X-Factor	Three cohorts (0.2%, 0.4%, 0.6%)	Implicit in the X-Factor
Earnings sharing mechanism	No earnings sharing	If actual ROE is 300 bp above approved ROE; 90% of excess earnings is shared with customers	Weather normalized actual ROE is 100 bp above approved ROE; excess earnings is shared a 50/50 basis.	No earnings sharing	Yes, 100 percent after 375 bp. For less than 375 bp varied between 50% to 75% (for customers)
Off-ramps / re-openers	+/-300 bp weather normalized ROE for two consecutive years or +/- 500 bp in one year	No off-ramps (The initial settlement included an off-ramp).	+/- 300 bp normalized ROE for one year	+/- 300 bp weather normalized ROE for one year	3 consecutive years with no earned incentive return. Cumulative excesses or shortfalls exceeding 1.5 percent of rate base

12 For the determined elements of the OEB's Fourth Generation Incentive Rate Setting (productivity factor, SQIs, and efficiency carry-over mechanism), the Third Generation Incentive Rate Making data is used.

13 GDP IPI FDD is the Gross Domestic Product Implicit Price Index times Final Domestic Demand

	Alberta Electricity and Natural Gas	Union Gas (2008-2012)	Enbridge Gas (2008-2012)	OEB 4th Generation IR (Electricity)[12]	Gaz Metro (2007-2012)
					2 consecutive years with inflation that is greater than 5%
Efficiency carry-over mechanism	Yes, ROE Bonus	None	None	None	Yes, It incorporates previous productivity gains based on a moving 5-year average
Rebasing	COS rebasing at the end of the PBR period (No annual re-calibrating or true-up)				Yes, it includes annual cost of service application
SQIs	Yes (No penalty/reward mechanism attached to SQIs in the PBR plan)				Yes, linked to financial incentives
K-factor	Capital trackers	None	None	Incremental capital module (ICM)	Not applicable
Y-factor	Included in all plans				
Z-Factor	Included in all plans				

1

The following high-level conclusions can be derived from the above table:

1. The appropriate choice for regulatory proceeding (negotiated settlement or litigation) is highly dependent on the number of utilities that are part of the proceeding. For major gas local distribution companies (LDCs) such as Gaz Metro, Union Gas and Enbridge Gas, separate proceedings were initiated and negotiated settlement was used to address the unique circumstances of each utility. The Alberta Utilities Commission (AUC) PBR initiative as well as the Ontario Energy Board (OEB) renewed regulatory framework for power distributors, which were applicable to a number of utilities, were resolved by hearing.
2. All the utilities have a 5 year price control period (i.e. PBR term) and all plans cover both O&M expenditures and capital expenditures.
3. The measure of the inflation factor is evolving and the use of a composite factor (labour and non-labour inflators) and industry specific indices are on the rise. Both the AUC's recent initiative and the OEB's 4th generation Incentive Regulation (IR) for power distributors adopt a composite inflator.
4. There is no single approach to estimating the X-Factor. The X-Factor in OEB's 3rd generation IR and AUC's PBR initiative are based on exact productivity percentages that were calculated from a specific TFP study. On the other hand, Union Gas' and Gaz Metro's final X-Factors were a product of a negotiated settlement rather than any specific TFP study (in the case of Union Gas, TFP studies were used as a guide but not as an ultimate number). The Enbridge Gas X-Factor estimation was also based on a negotiated settlement and, similar to FEI's 2004 final X-Factor settlement, based on various percentages of the inflation factor.
5. There is no particular pattern with regard to the use of earnings sharing mechanism, stretch factors, off ramps, re-openers and efficiency carry-over mechanism. The use and design of these regulatory tools are mainly based on the overall design of the PBR and/or negotiations between the Companies and interveners. In addition, the design of these items is inter-connected. For instance, the trigger point in an off-ramp provision may be higher for PBR plans without a sharing mechanism. Another example is the stretch factor. Stretch factors are ordinarily a substitute for an Earnings Sharing Mechanism (ESM) and the amount of stretch factor is mainly subjective.
6. Annual capital re-basing is deemed as inappropriate in both Alberta and Ontario jurisdictions and cost of service re-basing is limited to the end of the PBR term. The Gaz Metro hybrid incentive plan included annual cost of service applications, which reduced the strength of the incentive.
7. In Alberta and Ontario the SQIs are monitored during the PBR plan however there is no direct reward or penalty mechanism attached to SQIs. Gaz Metro is the only utility among those reviewed that has had SQIs with financial penalties or rewards.

6. FEI 2014 PROPOSED PBR

6.1 PBR PRINCIPLES

In developing the PBR Plan, FEI applied the principles and objectives articulated below. B&V's view is that these principles and objectives are appropriate. There are many ways to articulate principles and objectives, and B&V is aware that various jurisdictions do articulate them differently. However, there are common threads or themes in the principles articulated by most jurisdictions, and the principles and objectives articulated by FEI are consistent.

The guiding principles are, in no particular order:

Principle 1: The PBR plan should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the PBR plan.

Principle 2: The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

Principle 3: The PBR plan should recognize the unique circumstances of the Company that are relevant to the PBR design.

Principle 4: The PBR plan should maintain the utility's focus on maintaining, safe, reliable natural gas service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.

Principle 5: The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

6.2 PROPOSAL

In this section, FEI outlines the key elements of the proposed PBR Plan. FEI's proposal builds on the 2004 PBR Plan, with some adjustments to enhance a customer focus and further promote FEI's productivity improvement culture. The proposed PBR shares common elements with plans in other jurisdictions, but FEI has preferred continuity with the past experience in circumstances where there are no obvious benefits, and possibly disadvantages, associated with adopting a new approach employed in the plans in other jurisdictions.

The material in this section should be read in conjunction with the reports prepared by B&V, included in Appendices D1 and D2, in which B&V provides its expert assessment of individual elements of FEI's past plan as well as PBR Plans in place elsewhere. As indicated previously, B&V endorses the overall proposed PBR Plan as being reasonable in the circumstances of FEI, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regard the appropriate X-Factor as being approximately zero based on the TFP study they conducted and the specific elements of the proposed PBR Plan. In other words, FEI's proposal is more favourable to customers than they would recommend. FEI is nonetheless comfortable with the proposal as part of an overall package.

Table B6-1 summarizes the items of FEI's proposed PBR Plan. Each item is discussed separately in the sections below.

Table B6-1: Summary of 2014 PBR Plan Proposal

Item	2014 PBR Application
Term	A five-year term from 2014-2018 is proposed.
Inflation Factor (I-Factor)	A weighted average of BC Average Weekly Earnings (AWE) for labour costs and BC-CPI for other O&M costs will be used to determine the I-factor, which will be reforecast annually.
Productivity Improvement Factor (X-Factor)	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M is proposed. 2013 approved O&M expenditures (with adjustments) are adopted as the base O&M The O&M formula will adjust the prior year's formula O&M by forecast customer growth and (I-X). O&M will not be rebased during the PBR term but will be subject to true-up for actual customer growth.
Controllable Expenses - Capital	A formula based approach for Capital is proposed using 2013 approved capital expenditures (with adjustments) as the base. Two formulas will be applied. Growth Capital is tied to forecast service line additions and other regular capital is tied to forecast growth in average customers. The (I-X) escalation factor is also applied to both formulas. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%. Formula amounts will be subject to true-up for actual cost driver results (i.e. service line additions or average customers).
Flow Through Expenses and Revenues	Revenues and non-controllable costs are forecast each year and flowed through in rates each year in the Annual Review Process.
Exogenous Factors	Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and Commission decisions will be flowed through in rates.
Earnings Sharing Mechanism	The PBR includes a 50/50 earnings sharing mechanism for returns above or below the approved return on equity
Efficiency Carry-Over Mechanism	An expanded Efficiency Carry-over Mechanism is proposed based on a rolling 5-year benefit calculation derived from O&M and capital efficiencies achieved each year.
Service Quality Indicators	10 SQIs (7 SQIs with a target benchmark and 3 informational measures) are proposed that deal with emergency response, customer service (telephone service, billing), employee safety and meter exchanges.
Mid-Term Review and Off Ramps	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	Annual reviews are also proposed for this PBR.

6.2.1 Term

FEI proposes a five-year term for the PBR, effective 2014 to 2018. Five years is a commonly adopted PBR term in North America, and similar in term to previous plans in BC. The proposed term is one year less than FEI's 2004 PBR Plan, which became six years in duration after an approved two-year extension was added to the initial four-year term. There are two key advantages to the proposed term, relative to a shorter term.

First, the five-year term addresses a key objective regarding regulatory efficiency as the term minimizes the frequency of comprehensive revenue requirement applications.

Second, this five year period provides an adequate amount of time for FEI to attain cost savings from capital investments and other efficiency initiatives. These types of investments generally require a few years for the benefits to be realized. An example of this can be seen in FEI's experience (noted above) in the 1998-2001 PBR where break-even on the efficiency investment did not occur until the fourth and last year of the plan. In addition, the proposed Efficiency Carry-over Mechanism (discussed below) will provide incentive for FEI to continue pursuing efficiency gains throughout the PBR term for the long term benefit of customers.

The perceived challenges associated with a longer PBR term relate to risk to customers and the utility, as well as regulatory transparency. The potential risks of a longer term PBR for either the utility or its customers are typically mitigated through other plan provisions such as exogenous factors, re-openers or off-ramps. There are checks and balances implicit in the proposed PBR Plan, discussed below, which mitigate risk to either customers or the Company in the context of a five-year term. Moreover, FEI proposes an annual review (and mid-term review) of Company performance as a means of maintaining transparency. The achieved efficiencies, service quality measure results, earnings sharing results, and the off-ramp mechanism (if necessary) will be reviewed in that context and will provide regular opportunities during the term to assess the success of the PBR Plan.

B&V has commented on the considerations that go into the selection of a PBR term in its PBR Report (Appendix D1), where it discusses the five-year terms adopted by the AUC and the OEB. B&V highlights that the determination of the length of term should only be made in conjunction with other elements of a PBR plan. It states, for instance at p.36:

> *"While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans*

have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable."

B&V's view is that 5 years is a reasonable plan term for FEI's PBR Plan, having regard to the other elements of FEI's proposal.

6.2.2 PBR Inflation and Productivity Factors

6.2.2.1 Inflation Factor (I – Factor) Proposal

The use of an inflation or I-factor in a PBR plan is to provide recognition that utility costs are subject to the general inflationary pressures occurring in the economy, although the specific pressures or weightings of the various inflationary influences may be different than for the economy in general. This is one area where FEI is proposing a change from the 2004 PBR Plan. FEI's previous PBRs calculated an average inflation rate for British Columbia using a combination of sources for CPI forecasts. These forecasts were collectively referred to as the BC-CPI. FEI proposes to use instead a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to BC All Weekly Earnings (BC-AWE) and non-labour indexed to BC-CPI. FEI believes it is more appropriate to use a composite labour and non-labour inflation index in determining the I-Factor since this is more reflective of Company costs, which consist of both labour and non-labour components, than an economy-wide inflation measure such as CPI.

Two recent PBR initiatives (the AUC's generic PBR initiative and the OEB's 4th Generation PBR for Electricity Distributors) have adopted a weighted composite I-factor. This change away from the prior approach of using BC-CPI alone is endorsed by B&V. B&V discusses the precedent and rationale for the use of the weighted composite I-factor in Appendix D1 PBR Report at pages 35 and 46. B&V states at p.46, for instance: *"It is instructive to note that the evolution of PBR Plans for FEI includes a newly proposed change to a composite measure of inflation more reflective of the cost drivers for FEI. Since FEI is proposing both a general measure of inflation and a labor measure, this is a better reflection of price changes.*"

In selecting the appropriate inflation indices, FEI considered whether or not the indexes were:

1. Indicative of the change in inflationary pressures that the Company expects to experience over the term of the PBR plan;
2. Published by a reputable, independent agency and made readily available on at least an annual basis;
3. Transparent, simple to calculate and easy to understand; and
4. Reasonably stable.

These selection criteria and the use of a composite I-Factor for the PBR are consistent with the model adopted in Alberta as approved by AUC Decision 2012-237[14]. FEI believes the BC-AWE and BC-CPI indexes satisfy each of the aforementioned criteria, as the indexes used are publicly available data that is published by the federal and provincial governments, as well as by three of Canada's largest financial institutions.

With respect to determining the composite factor weightings, FEI believes the weighting should reflect the Company's proportion of labour and non-labour costs.

An analysis of FEI's 2012 Actual O&M costs indicates that 55 percent percent of costs are labour-related while 45 percent of costs are non-labour related[15]. For that reason, FEI proposes the following I-Factor determination for the PBR period:

$$I_{t+1} = 55\%\, BC - AWE_{t+1} + 45\%\, BC - CPI_{t+1}$$

Where: *I=Inflation Factor*
BC-AWE = labour index
BC-CPI = non-labour index
t = current year

Consistent with the methodology employed in FEI's previous PBRs, FEI has calculated an average BC-CPI forecast from the sources listed in the following table[16]:

Table B6-2: BC-CPI Forecasts for the PBR Period[17]

BC CPI Forecast	2014	2015	2016	2017	2018
Toronto Dominion Bank	2.00%				
Royal Bank of Canada	1.60%				
Bank of Montreal	1.70%	2.00%	2.00%	2.00%	2.00%
Canadian Imperial Bank of Commerce	1.80%				
Conference Board of Canada	1.90%	2.10%	2.00%	2.10%	2.10%
BC Ministy Of Finance	2.00%	2.10%	2.10%	2.10%	
AVERAGE	**1.83%**	**2.07%**	**2.03%**	**2.07%**	**2.05%**

In addition, in November 2012 the Conference Board of Canada published the following forecast of annual changes in average weekly earnings data for British Columbia:

[14] Appendix D9 AUC Decision 2012-237 Rate Regulation Incentive Distribution Performance Based Regulation
[15] Section E, Schedule 15, Line 6, Column 2 Labour costs of $122,164 compared to Section E, Schedule 15, Line 17, column 2 Non-Labour costs of $97,540.
[16] Backup for the referenced sources of BC-CPI and BC AWE is found in Appendix E1. All referenced sources for BC-CPI do not provide five-year forecasts. For the rate setting process each year during the PBR term the average of all six sources for the coming year will be used.
[17] Refer to Appendix F1 for source information.

Table B6-3: BC AWE Forecasts for the PBR Period[18]

BC Average Weekly Earnings Forecast	2014	2015	2016	2017	2018
AVERAGE	2.70%	2.70%	2.60%	2.60%	2.50%

Based on these tables, the 2014 BC-CPI and BC-AWE rates are forecasted to be 1.83 percent and 2.70 percent respectively. As such, FEI proposes to use an I-Factor of 2.31 percent (calculated as (45% x 1.83%) + (55% x 2.70%)) for 2014.

As part of the PBR Annual Reviews, FEI will update both the BC-AWE and BC-CPI rates (using the same sources referenced above) to determine the value of the I-Factor for the 2015 through 2018 years. FEI proposes that the composite's weighting remain constant throughout the PBR Period.

6.2.2.2 X – Factor Estimation

The X-Factor (also known as efficiency factor or productivity offset) is a fundamental element of performance-based regulation. It represents the amount by which a company is expected to outperform the industry and economy-wide productivity gains. The X-Factor can be described as part of a forward-looking benefit sharing mechanism in which the company allocates the expected X-Factor productivity gains to customers, regardless of the firm's realized productivity. FEI proposes a fixed X-Factor of 0.5 per cent (inclusive of any stretch factor) for its 2014 PBR.

FEI commissioned B&V to perform a detailed analysis of industry-wide TFP growth and provide a survey of measured TFPs among natural gas utilities in other North American jurisdictions. FEI has also considered the business conditions expected to affect BC's natural gas utility industry during the PBR term as well as the analysis of proposed X-Factor rate impacts relative to forecast rate changes using the high level cost of service capital and O&M inputs discussed in Sections C3 and C4 to derive a reasonable and fair X-Factor. FEI has already embedded a great deal of efficiency into its operations. The proposed 0.5 percent expected productivity gain exceeds the measured industry productivity levels and represents a real challenge to the Company to seek additional efficiency and continue with its productivity improvement culture.

The following sections provide a discussion and explanation of the general literature on X-Factor estimation approaches as well as the rationale for FEI's proposed 0.5 per cent X-Factor, and were prepared with the assistance of B&V, reflecting B&V's views except where attributed to FEI.

[18] Refer to Appendix F1 for source information.

Approaches to X-Factor Estimation

Different approaches can be used to set the X-Factor. These can be classified into two major groups: "Pure TFP approach" and "Hybrid Judgement-based approach".

Under a "pure" TFP approach, the X-Factor is derived from rigorous mathematical models that calculate the growth of total factor productivity. In this approach the X-Factor is ordinarily defined as the measured industry TFP growth, plus an adjustment for any difference between the inflation index used in the PBR index formula and the rate of input price inflation for the regulated sector. The measured TFP growth is influenced by the following elements:

- TFP growth estimation methodology: Parametric (econometric modelling) and non-parametric (Index-based approaches) models are two major techniques used for the calculation of industry-wide TFP growth. The econometric models are statistically more robust; however, their complexity and extensive assumptions about items such as companies' production and cost functions have been criticized and limited their application. The index-based approaches on the other hand are well-established and relatively easy to understand as they do not impose any functional form on the relationship between inputs and outputs. However they are also based on assumptions that might not always hold. For instance, an index-based TFP may not yield a reliable estimate of future productivity gains if business conditions in the future differ from the past.
- The sample of companies: The first step in estimation of industry-wide TFP growth is to select companies from the applicable industry for which data is available. A broad sample is useful. Given that it is impossible to have exactly comparable firms, it becomes important to take the results of the analysis and consider them in light of the circumstances of the specific utility in question and the overall elements of its proposed PBR Plan.
- The measurement period: The TFP growth result is sensitive to the length of measurement period. In general it makes sense to use the most recent data, unless the recent past exhibits anomalous events that are not expected to continue during the PBR term. The evidence from other North American jurisdictions where PBR design has considered TFP analysis, demonstrates that the length of the study period for calculation of TFP varies between 5 to 20 years. This wide range may be partially explained by the choice of the measure of output in the TFP calculation. For example, an output measure based on customers or capacity is relatively stable so a shorter study period is adequate. However using throughput as a TFP output measure requires a longer study period to accommodate such factors as weather variations and impacts of the business cycle.
- Choice of Output measures: Output measures are representative of a regulated firm's cost drivers. Ideally a comprehensive set of cost drivers should be used to best capture the scale of the utility activities and services that the company undertakes. According to the research conducted by B&V, costs for natural gas distribution companies are mainly

caused by a combination of customers, density, the age of assets and design day capacity served by the utility system. Some jurisdictions have used volumetric output measures such as throughput in TFP analysis; however B&V notes that a change in the level of throughput for a natural gas LDC does not change the level of fixed costs for the utility delivery function, and therefore volumetric output measures mislead the TFP results. B&V also concludes that the anomalies in the TFP results from external factors such as weather variations or economic conditions mean that the volumetric approach requires longer study periods. (However, using a longer study period does not overcome the other shortcomings noted in Appendix D2 of using throughput as a TFP output measure).

- Choice of Input measures: The input measures represent the operating and capital costs associated with the utility delivery function. Inclusion or exclusion of particular cost items may add to the bias of TFP estimates. For instance, the B&V report indicates that in the AUC decision 2012-237, general plant was excluded from the capital component of the costs and therefore the AUC-adopted TFP study fails to recognize the capital costs associated with maintenance of the distribution system (such as costs related to line trucks and other vehicles).

The result of a TFP growth study is thus dependent on expert judgement in a number of areas, such as the definition and choice of an appropriate set of companies, the data source, the input and output indices as well as the measurement period. In practice, the X-Factor values estimated through the pure TFP approaches are often adjusted to reflect circumstances of a specific company and by a judgement-based stretch factor. The B&V TFP Study demonstrates that in some cases, the subjective stretch factors are much greater than the measured TFP. Both the AUC and OEB final X-Factor values include stretch factor values and therefore represent some degree of subjectivity (ranging between 0.2 and 0.6 percent).

Under a hybrid judgement approach, the mathematical derivations of the X-Factor, such as TFP studies, are still used as guidance for the determination of X; however, practical matters such as the actual effects of X on the company's bottom line and expected business conditions during the PBR term are also considered to determine a final measure. Researchers such as Crew and Kleindorfer (1996)[19] support the hybrid judgment-based approach and suggest that mathematical models are based on assumptions that may not always hold and therefore justify some level of judgement to adjust the results and choose a reasonable value for X. In other research, Stephen Littlechild[20] (a principal originator of the price cap regulation) indicates that the initial level of X should be "set as part of a whole package of measures, whose parameters affect the costs, revenues and risks of the regulated company". These parameters include items such as the PBR term, cost items subject to flow-through in customers' rates, the implementation of other sharing models such as earnings sharing mechanisms, the use of

[19] Appendix D8-2, Crew 1996 Incentive Regulation in the UK
[20] Appendix D8-3, Beesley, M.E. and Littlechild, S.C., The Regulation of Privatized Monopolies in the United Kingdom, Rand Journal of Economics, Autumn 1989.

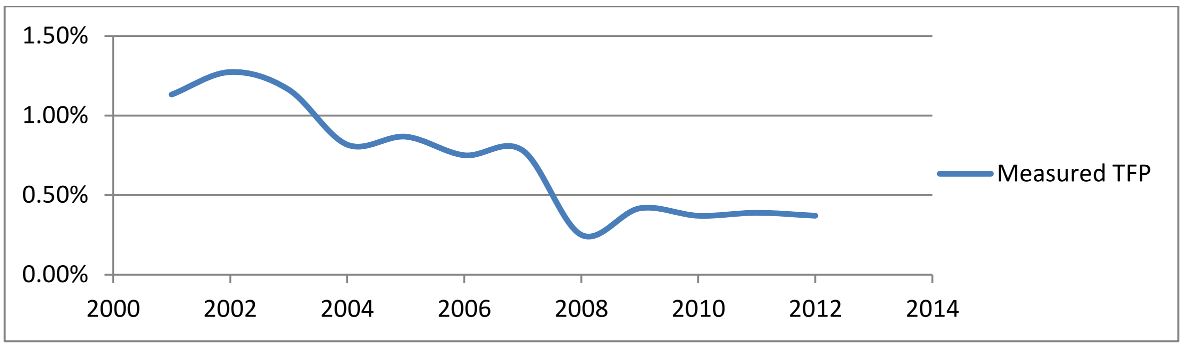
historical or expected performance as basis for X-Factor estimation, etc. For instance, it can be argued that the X-Factor for a PBR plan with an earnings sharing mechanism is less significant than under a plan with no earning sharing mechanism.

B&V TFP Report

Due to the high complexity of TFP estimation methodologies and in order to provide an independent expert analysis of TFP results, FEI retained the services of B&V to prepare a TFP study of the utility industry and to assess and benchmark the results of the TFP studies in other jurisdictions. The B&V TFP Report is found in Appendix D2.

The B&V survey of TFP studies used in the determination of North American electric and natural gas distributors' X-Factor values indicates a clear downward trend for TFP values in recent years. The graph below displays this downward trend for the 2001-2012 period.

Figure B6-1: The Historic Trend of Approved TFP Values in a Sample of North American Jurisdictions



This declining trend can also be seen as a pattern in individual jurisdictions. For example, Ontario's 3rd Generation Incentive Regulation (2009-2013) which was based on a TFP study conducted by the OEB's consultant was estimated at 0.72 per cent, while the most recent study prepared by the same consultant for the 4th Generation IR (2014-2018) indicates a negative TFP growth of -0.05 to -0.03 per cent. B&V concludes that the downward trend of TFP growth is mainly caused by capital intensive infrastructure replacement programs in both natural gas and electric utilities, which drive up input costs without increasing output. B&V expects that this trend will continue during FEI's proposed five year PBR term.

In addition to the survey analysis, B&V prepared its own TFP growth calculation. The analysis is based on three different output measures and the TFP results range between -3.1 to -4.9 per cent. The following is a summary of the main elements of B&V's analysis:

- X-Factor and TFP estimation approach: The B&V study confirms that the hybrid judgement-based approach is preferred. According to B&V, the estimated TFP value is one component of the X-Factor estimation process and that the measured TFP value should be considered along with other elements of the proposed plan to determine a reasonable X-Factor. In addition, the B&V TFP estimation methodology is based on a non-parametric index-based approach. This will help with the transparency and ease of understanding of the processes and results.

- The choice of companies: Given the lack of a centralized database of Canadian utilities and the different reporting requirements among Canadian jurisdictions, B&V compiled TFP data on 95 US-based natural gas LDCs operating in 30 states. U.S. data has been used in other Canadian jurisdictions as well. It is appropriate because of the operating similarities. For instance, the North American Energy Standards Board includes gas utilities in both Canada and the United States, assuring a consistent approach to a variety of operating and other activities between the two countries.
- The measurement period: The B&V study is based on a five year measurement period (2007-2011). The five year measurement period is considered appropriate due to the relative stability of selected output measures (customers and capacity), and the fact that the measured TFP uses a period where the business conditions are similar to those expected during the PBR term.
- Choice of Output Measures: To investigate the sensitivity of TFP analysis to different utility delivery function cost drivers, the analysis provides three different output measures based on the critical variables of customers served and system capacity, and a density-weighted composite factor of these two variables.
- Choice of Input Measures: The input measure includes a capital component and a composite component that reflects labour, materials, services, and rents. The capital component is designed based on the "Kahn" methodology (developed by noted regulatory economist Alfred Kahn) and is measured as Operating Revenue excluding gas costs and all other operating and maintenance expenses. The resulting revenue represents the cost of capital including return, depreciation, and taxes. The measure of all other costs is a direct composite measure as reported in the financial reports of each company.

The measured negative TFP growth is reflective of the business conditions faced by the natural gas utilities in Canada and BC. The following section addresses the need to consider the results of the measured TFP value in the context of the specific utility and PBR proposal.

Hybrid Judgement Approach and Derivation of Proposed X-Factor

FEI is proposing a TFP of 0.5 percent, which is well above the range specified in the B&V TFP Report. FEI's decision to adopt a more challenging X-Factor than that suggested by B&V's TFP Report for the natural gas industry is intended to account for FEI's specific circumstances and the overall design of the proposed PBR plan.

B&V and FEI are in agreement that B&V's TFP Report produces a more negative TFP number than would be applicable to FEI by virtue of how TFP data has been provided for the sample companies in TFP Report. The capital component in B&V's study is measured as the difference between operating revenue (excluding gas costs) and all other O&M expenditures, and which therefore includes all capital costs, whether pertaining to base capital or growth spending, as well as the infrastructure replacement programs that have been more prevalent in recent years. In contrast, in FEI's proposed PBR Plan, large capital projects approved as CPCNs are excluded from the (I-X) mechanism and are treated under a separate regulatory approval process. Due to limitations in the data used in the TFP Study, the revenue earned by the surveyed companies from these types of infrastructure projects or other particular categories of capital cannot be separated from the capital component as a whole. Therefore, a certain degree of educated judgement is required to adjust the TFP value for the companies in the study. The effect of FEI's proposal to exclude CPCN type projects from capital expenditures subject to the I-X mechanism is to moderate the measured negative TFP value applicable to the industry as a whole.

The reasonableness of FEI's proposed X-Factor can be assessed by comparing the impact of the proposed X-Factor on forecast rate changes under a formula relative to forecasted rate changes under the cost of service model. As FEI explains in Section B7 of this Application, the rates arising from PBR formulas (the combination of proposed 0.5 per cent X-Factor and the proposed composite inflator) will lead to average delivery revenues that are 2.0 percent lower than the average rates under the cost of service model which indicates that the proposed X-Factor is an ambitious estimate of expected productivity gains and represents a considerable challenge to the Company. FEI considers that this conclusion is further supported by the review of the most recent X-Factors approved or recommended in other North American jurisdictions, the declining trend of measured TFP values across North America and the negative measured TFP value of the B&V TFP Study. In addition, FEI's proposed PBR Plan includes an earnings sharing mechanism with no deadband which will further reduce the earnings of the Company in comparison with other jurisdictions.

All things considered, FEI considers that a 0.5 per cent X-Factor is an appropriate and reasoned value in the context of FEI and the overall PBR Plan that ensures the continuation of a productivity improvement culture. However, as indicated previously, this is the one area where B&V and FEI part company. B&V are of the view that even accounting for the above factors, the X-Factor should be no higher than approximately zero in order to be theoretically justifiable within the context of FEI's PBR Plan. B&V's evidence is an indication of the real challenge that the Company has set for itself in the proposed PBR Plan.

6.2.3 Determination of FEI Rates

The 2014 PBR Plan applies only to the delivery portion of customers' rates. The commodity and midstream components of customer rates are set through separate flow-through regulatory processes. Delivery costs include the costs incurred to build, maintain, finance and operate the infrastructure necessary to deliver natural gas and provide service to customers.

The proposed PBR formulas and flow-through cost components will affect the delivery rates, exclusive of rate riders and applicable taxes. In general, rate riders pertain to an established mechanism, approved in a previous Commission process and order, for recovering or refunding specific cost or revenue variances. Rate riders will continue in the approved fashion throughout the PBR term.

From 2014 onwards, the controllable expenditures will be adjusted annually by the PBR formula as outlined in Sections B6.2.4 and B6.2.5 which follow. Other items will be re-forecast annually as part of the Annual Review process. At that time, the delivery rates for the following year will be determined. Section B6.9 describes the Annual Review process.

Operating and maintenance expenses and capital expenditures are the two main types of controllable expenses that present an opportunity for FEI to identify and achieve cost savings. As discussed in the respective sections below, a formula is applied to the base year O&M and capital expenditures (2013 Approved amounts as adjusted to form the 2013 Base, discussed below) that will determine the amount of expenditures from 2014 to 2018 that will be included in the delivery rates. FEI will attempt to meet and ideally incur expenses below those amounts in each year, with net savings to be shared according to the proposed Earnings Sharing Mechanism as discussed further in Section B6.5.

6.2.4 O&M under PBR

2013 O&M expenditures are now at a level that reflects substantial productivity savings relative to previous years, yet still ensures that safety standards and other service requirements continue to be met.

For the PBR Period, actual O&M expenditures will not flow through to rates. Instead, each year the component of rates designed to recover O&M expenses will adjust the previous years' amount by the formula which includes a productivity factor. This will incent the pursuit of further efficiencies in O&M expenditures in the context of meeting SQIs and providing reliable service.

6.2.4.1 2013 Base O&M

Recognizing that the O&M Base for the 2014-2018 formula should be an O&M number that has undergone a full review in a public hearing, FEI has used the 2013 Approved O&M as the starting point for the O&M formula. A number of adjustments are then made to this amount to arrive at the "2013 Base". The adjustments are of three types:

1. An adjustment to recognize the sustainable savings that were realized in 2012 that should be carried forward to future years;
2. Adjustments to include actual incurred 2013 "non-controllable" O&M that is held in deferral accounts in 2013; and
3. Accounting changes that reclassify items from O&M to capital.

The goal of these adjustments is to determine the appropriate starting point for O&M expenses in the upcoming PBR Period. B&V considers this approach is reasonable given the fact that the current rates were set based on a fully litigated hearing that occurred recently. It is common to use approved rates in circumstances where the revenue requirements were recently assessed, and making known and measurable adjustments is also appropriate.

Under the above methodology, the 2013 Base is calculated as follows:

Table B6-4: 2013 Base O&M

		($ thousands)
2013 Decision		**236,003**
Sustainable Savings		(14,670)
2013 Deferrals:		
PST (full year impact)	762	
BCUC Fees & Insurance	1,016	
Pension (O&M portion)	10,605	12,383
Accounting Changes:		
Allocation of retiree pension/OPEBs	(930)	
Capitalization of annual software costs	(1,800)	(2,731)
2013 Base		**230,985**

Sustainable Savings:

The total sustainable savings that are being embedded in the 2013 Base O&M for the future benefit of customers is $14.67 million[21]. A breakdown of this total sustainable savings by department is shown in Table C3-2. Further description of the nature of these savings is provided in the departmental narrative that follows within Section C3.

2013 Deferrals:

The 2013 deferral adjustments reflect the re-basing of 2013 Approved to 2013 expected Actual amounts for those items that are considered non-controllable, and for which the variance is captured in a deferral account. In 2013, FEI will record the following amounts in O&M related deferral accounts:

1. $571 thousand[22] in the Tax Variance deferral account related to PST for 9 months of 2013 (equivalent to the $762 thousand shown above for the full year). In addition,

[21] Of this amount, $10.285 million in savings achieved in the Customer Service department in 2013 and deferred to the Customer Service Variance deferral account (Section E Financial Schedules Schedule 47, Line 26 Column 4)
[22] Appendix F7, 2013 FEI Summary of PST Expenditures for 2013 Revenue Requirements Lines 1, 6, 10, 11

$1.664 million[23] was included relating to PST on capital in the calculation of the amount to be included in the Tax Variance deferral account. Grossed up for a full year, the $1.664 million becomes $2.219 million, of which $1.999 million is related to capital expenditures and has been adjusted in the Base Capital below, and the remaining $220 thousand relates to removal costs (captured in another deferral account).

2. $923 thousand in the BCUC Levies Variance deferral account[24], representing the difference between the actual amounts that will be paid in 2013 and the amounts approved in rates.
3. $93 thousand in the Insurance Variance deferral account[25], representing the difference between the actual insurance that will be paid in 2013 and the amounts approved in rates;
4. A total of $12.607 million to the Pension and OPEB Variance deferral account[26]. Of this amount, $10.605 million is related to O&M, $1.311 million is related to capital expenditures and has been adjusted in the Base Capital below, and the remaining $691 thousand relates to removal costs (captured in another deferral account).

Accounting Changes:

The two accounting changes (allocation of retiree pensions/OPEBs and capitalization of annual software costs) are described in further detail Section D3.1 and serve to reallocate costs from O&M to capital.

6.2.4.2 2014 - 2018 O&M

The 2013 Base O&M is then escalated using the formula approach. Excluded from the O&M formula approach are pensions and OPEBs, insurance and also the O&M related to Rate Schedule 16[27]. The pensions, OPEBs and insurance were also excluded from the formula in the last PBR and were considered "flow through" items in recognition of their uncontrollable nature. The Rate Schedule 16 O&M has been excluded because these costs are directly tied to incremental revenue that is not part of the formula approach.

As in the 2004 PBR Plan, the PBR formula FEI proposes to apply to the O&M is tied to the average number of customers. FEI will reforecast the average number of customers for the upcoming year in the Annual Review. The following formula illustrates the formula applied to O&M:

[23] Appendix F7, 2013 FEI Summary of PST Expenditures for 2013 Revenue Requirements Lines 2 and 3
[24] Section E financial schedules Schedule 47, Line 22, Column 4
[25] Section E Financial Schedules Schedule 47, Line 20, Column 4
[26] Section E Financial Schedules; Schedule 47, Line 21, Column 4.
[27] Pursuant to Commission Order G-88-13 received on June 4, 2013, O&M related to Rate Schedule 16 may be updated in an evidentiary update to this Application once the Rate Schedule 16 decision has been fully evaluated.

$$OM_t = OM_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *OM=Operating and Maintenance Expense subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The inputs used for calculating the O&M under the PBR Plan, include:

1. The 2013 O&M Base;
2. The 2013 base and forecasted number of average customers, including its year to year per cent change;
3. The composite I-Factor values; and
4. The Productivity X-Factor.

B&V consider that linking O&M to the number of customers is appropriate. B&V has noted in its PBR Report and TFP Report that customers and capacity are the principle drivers for costs. For O&M, a number of the specific costs are driven by number of customers. Other costs are driven by capacity. The influence of the capacity component on O&M costs is not easily measured and would lack transparency if that measure were used. As a result, B&V believes it is appropriate to use customers since system capacity is also related to the number of customers and customer count becomes a reasonable proxy for the capacity variable in the formula. It effectively adds an estimate of additional O&M expense associated with system growth to the plan's revenue adjustment.

The O&M allowed under the PBR Plan is shown in Table B6-5. As indicated above, the O&M allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecasted number of customers and the re-forecasted composite inflation rate for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

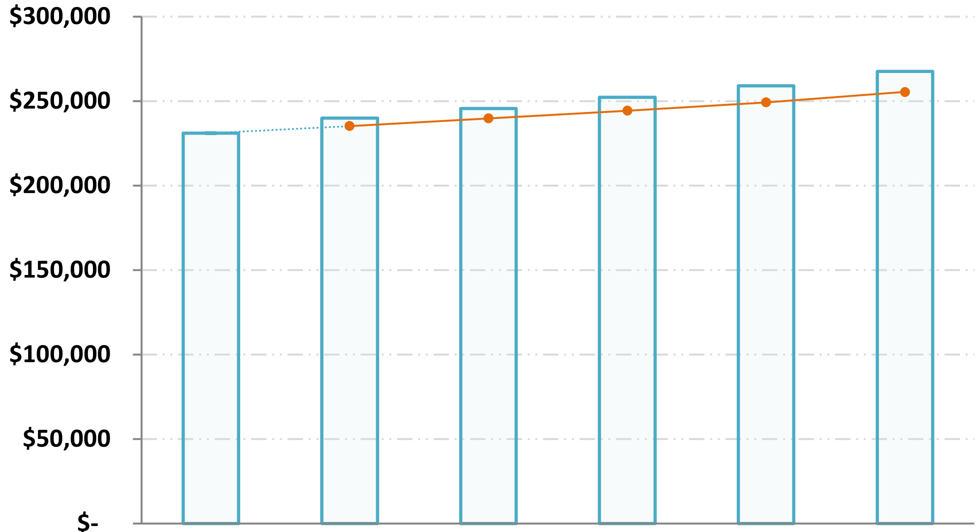
Table B6-5: Forecast O&M Formula Results[28]

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
2013 Base O&M ($000)	**$ 230,985**					
LESS O&M Tracked Outside PBR Formula:						
Pension / OPEB ($000) (O&M Portion)	$ (25,313)					
Insurance ($000)	$ (4,710)					
RS 16 O&M	$ -					
O&M Applicable to PBR Formula:	**$ 200,962**					
Average Number of Customers	840721	845495	850620	856001	861402	866681
% Change in Customer Additions		**0.57%**	**0.61%**	**0.63%**	**0.63%**	**0.61%**
Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
I-X Mechanism (1+I-X)		**101.81%**	**101.92%**	**101.84%**	**101.86%**	**101.80%**
Gross O&M Under PBR ($000)		$ 205,761	$ 210,983	$ 216,224	$ 221,636	$ 227,008
ADD: O&M Tracked Outside of the Formula						
Pension / OPEB ($000) (O&M Portion)		24113	22426	21340	20520	20973
Insurance ($000)		4990	5290	5610	5945	6300
RS 16 O&M		376	1089	1089	1089	1089
Total O&M Under PBR	**$ 230,985**	**$ 235,240**	**$ 239,788**	**$ 244,263**	**$ 249,190**	**$ 255,370**

Based on the results from Table B6-5 above and O&M forecasts provided in Section C3, Figure B6-2 below illustrates the comparison between the 5-year O&M forecasts, and the O&M calculated under the PBR Plan.

[28] Refer to Attachment 1 to Appendix E1 for the forecast of average customers.

Figure B6-2: Comparison of PBR O&M vs. Forecast ($000s)



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
O&M Forecast	$230,985	$239,861	$245,622	$252,235	$259,035	$267,553
O&M Under PBR	$230,985	$235,240	$239,788	$244,263	$249,190	$255,370

As Figure B6-2 indicates, the O&M expense allowed under PBR falls below the forecasted O&M expense throughout the PBR Term. FEI believes this level of O&M expenditure allowed under PBR provides a strong incentive for FEI to find efficiencies for O&M spending.

6.2.5 Capital Expenditures under PBR

The formula–based capital portion of the PBR Plan pertains to the categories of capital expenditures over which the Company and its employees have some control. The other components of rate base such as working capital and deferred charge balances are largely beyond management control. The PBR formulas recognize this distinction and are thus applied to controllable capital expenditures and leave non-controllable rate base components for the annual forecasting process.

Capital expenditures include both regular capital expenditures and projects approved as CPCNs. FEI proposes the same treatment in the 2014 PBR Plan for regular capital expenditures and CPCN expenditures as was approved in the 2004 PBR Plan. Regular capital expenditures will be determined by formula and CPCN expenditures will be excluded from the formula and will continue to be subject to the minimum $5 million cost threshold. CPCN expenditures will only be included in rate base after receiving CPCN approval from the Commission and being placed into service. B&V considers that the exclusion of CPCN capital is an appropriate means of addressing capital under a PBR Plan. It is akin to the adoption of a "capital tracker", which is incorporated in PBR plans elsewhere. B&V describe the purpose of such mechanisms as follows in the PBR Report:

> *"Given the lumpy nature of capital additions and the growing need for infrastructure replacement, a separate capital tracker is both a reasonable term of a PBR plan and a critical element to maintain a safe and reliable system while providing the utility an opportunity to earn the allowed return. As noted elsewhere in the TFP reports, the addition of infrastructure replacement costs significantly impacts productivity because costs increase without any change in capacity or number of customers. Thus cost increases with no change in output assuring a negative TFP. By including a capital adjustment provision, regulators assure that a consistent program of infrastructure improvement occurs, meeting the goal of a safe and reliable utility system."* (Appendix D1, p.37)

There are three categories of regular capital expenditures which FEI has included in its PBR formula – growth, sustainment and other capital. A description of the types of capital included in each of these categories is included in Section C4.

Similar to O&M expenses, actual regular capital expenditures (i.e. actual plant additions) will not be flowed through in rates. The formula-based capital expenditures will be added to rate base and carried through the PBR term, however similar to the 2004 PBR, the formula-based capital expenditures, which use customer counts as a cost driver, will be trued up each year for actual customer counts.

6.2.5.1 2013 Base Capital

FEI has used the approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula. Similar to the methodology used to arrive at the 2013 O&M Base for PBR, adjustments are made to the 2013 Approved capital to arrive at the "2013 Capital Base". These include:

1. Adjustments to include the capital portion of 2013 actual "non-controllable" items that are held in deferral accounts in 2013 (PST and Pension amounts); and
2. Accounting changes that reclassify items from O&M to capital.

The goal of these adjustments is to determine the appropriate starting point or base for capital expenditures in the upcoming PBR period.

Under the above methodology, the 2013 Base Capital is calculated as follows:

Table B6-6: 2013 Base Capital ($ thousands)

	2013 Approved	2013 Adjustments PST	Pension Deferral Ammount	Pension Accounting Change	Vehicles	IT Cap	2013 Base
Growth Capital	$ 21,515	$ 367	$ 333	$ 236	$ -	$ -	$ 22,451
Sustainment Capital	$ 75,114	$ 1,280	$ 978	$ 694	$ -	$ -	$ 78,066
Other Capital	$ 26,069	$ 444	$ -	$ -	$ 2,860	$ 1,800	$ 31,173
Total Gross Capital	$ 122,698	$ 2,091	$ 1,311	$ 930	$ 2,860	$ 1,800	$ 131,689
(Contribution in Aid of Construction)	$ (5,400)	$ (92)	$ -	$ -	$ -	$ -	$ (5,492)
Total Net Capital	$ 117,298	$ 1,999	$ 1,311	$ 930	$ 2,860	$ 1,800	$ 126,197

All of the adjustments have been described above in Section B6.2.4.1 Base O&M with the exception of the Vehicles adjustment. The 2013 Capital Base has been restated to show vehicle purchases that will start in 2013, at the 2013 Approved amount for vehicle lease additions of $2.860 million. This adjustment is simply a reclassification of what was considered a capital addition (the vehicle capital lease) to a capital expenditure (an upfront payment for the purchase of a vehicle) and therefore does not affect total capital additions at all. This adjustment is described further in Section D3 Accounting Policies.

For capital, there is no need to adjust the 2013 Approved for savings realized in 2012. This is because amounts that were not spent in 2012 are not considered sustainable, since they have been carried forward to the 2013 Projection. As described in Section C4 on Capital Expenditures, the total of the 2012 Actual and 2013 Projection amounts are very close to the 2012-2013 RRA Approved amounts (approximately $2 million less), and in fact the 2013 Projection is $6.5 million higher than the 2013 Approved amount that is being used as a base for the PBR capital formula. Excluded from the capital expenditures subject to the formula are biomethane upgraders and CPCNs. Bio-methane upgraders are not recovered through the delivery rate, but rather through a separate rate setting process, and CPCNs are subject to separate regulatory processes. These separate processes are analogous to the capital tracker mechanisms adopted in other jurisdictions, in that the capital expenditures in these categories are outside the PBR formula just as the capital expenditures in capital tracker applications are outside the formulas in those jurisdictions. Consistent with past practice, the impact of CPCNs will not be included in rates until FEI has received Commission approval for such projects through separate processes.

Consistent with O&M, the capital portion of the annual pension/OPEB expense is flowed through outside of the formula.

6.2.5.2 2014 - 2018 Capital

Consistent with the 2004 PBR plan, FEI proposes to apply two capital formulas under the proposed PBR in determining total annual capital. B&V believes that using two separate formulas for capital results in a better estimate of overall capital than would result from a single formula. These formulas are described below.

Growth Capital under PBR

Of the three categories of regular capital expenditures that FEI has included in its PBR formula, Growth Capital differs from Sustainment and Other capital in that it is primarily driven by customer additions. In particular, Growth Capital is driven by service line additions (which are calculated as a percentage of gross customer additions) that arise from providing service for new customers. For that reason, the PBR formula FEI proposes to apply to Growth Capital is tied to the forecasted service line additions for the upcoming year. FEI will re-forecast the level of service line additions for upcoming years (driven off of the gross customer additions) in the PBR Annual Reviews.

In determining the Growth Capital allowed under PBR, a Average Growth Capital Cost[29] per Service Line Addition is calculated by dividing the current year's total Growth Capital by the current years' service line additions. This Average Growth Capital Cost per Service Line Addition is then escalated by the I-X mechanism and then multiplied by the forecasted level of service line additions for the upcoming year. FEI will recalculate the Average Growth Capital Cost per Service Line Addition yearly in the PBR Annual Review, based on the forecasted gross customer additions and resulting number of service line additions over the same period. The following formula illustrates the formula applied to Growth Capital:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: $GC = Growth\ Capital$
$SLA = Service\ Line\ Additions$
$t = Upcoming\ year$
$I = Inflation\ Factor$
$X = Productivity\ Factor$

The inputs used for calculating the Growth Capital under PBR include:

1. The Growth Capital 2013 base;
2. The 2013 Base and forecasted level of service line additions.
3. The composite I-Factor values; and

[29] Average Growth Capital Cost per Service Line Addition includes the average cost of a new service line as well the meter, regulator and average main extension costs.

4. The Productivity X-Factor.

The Average Growth Capital Cost per Service Line Addition allowed under the PBR Plan is shown in Table B6-7. As indicated above, the Average Growth Capital Cost per Service Line Addition allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecasted level of service line additions and the re-forecasted composite inflation rate for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

Table B6-7: PBR Growth Capital Formula Results

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Growth Capital ($000)	$ 22,450					
LESS: Capital Tracked Outside of the Formula:						
Insurance & OPEB ($000)	$ (569)					
Growth Capital Applicable to PBR Formula	**$ 21,881**					
Service Line Additions *	7989	8051	8407	8555	8444	8270
Average Growth Capital Cost per Service Line Addition	**$ 2,739**	**$2,788**	**$2,842**	**$2,894**	**$2,948**	**$3,001**
Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
I-X Mechanism (1+I-X)		**101.81%**	**101.92%**	**101.84%**	**101.86%**	**101.80%**
Gross Growth Capital Under PBR ($000)		$ 22,451	$ 23,893	$ 24,760	$ 24,894	$ 24,820
ADD: Capital Tracked Outside of the Formula						
Insurance & OPEB ($000)		$ 525	$ 473	$ 447	$ 433	$ 513
Total Growth Capital Under PBR ($000)	**$ 22,450**	**$ 22,976**	**$ 24,366**	**$ 25,206**	**$ 25,326**	**$ 25,334**

In B&V's view, the use of a new service line to measure the added costs for growth capital is significant because it represents adding a previously unserved premise[30] to the system. For a new premise, the costs include all the distribution facilities to interconnect the customer to the system. For growth capital, the formula essentially estimates the incremental capital for the new customer.

Sustainment and Other Capital under PBR

The PBR formula that FEI proposes to apply to Sustainment Capital and Other Capital is tied to the average number of customers. B&V notes that in actual fact, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no convenient measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since the addition of mains to serve customers adds new capacity to the system.

[30] In FEI's case new service lines are also installed where an older dwelling that previously had gas service has been torn down and replaced by a new dwelling.

FEI will reforecast the average number of customers for the upcoming year in the Annual Review. The following formula illustrates the formula applied to Sustainment and Other capital:

$$RC_t = RC_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *RC=Remaining Capital: Total of Sustainment & Other Capital*
AC=Average Customers
t = *Upcoming year*
I = *Inflation Factor*
X = *Productivity Factor*

The inputs used for calculating the Sustainment and Other Capital under the PBR Plan include:

1. The total of Sustainment and Other Capital 2013 base;
2. The 2013 base and forecasted number of average customers, including its corresponding yearly growth percentage;
3. The composite I-Factor values; and
4. The Productivity X-Factor.

The Sustainment and Other Capital allowed under the PBR Plan is included below in Table B6-8. As indicated above, the Sustainment and Other Capital allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecast number of customers and the re-forecast composite inflation rate for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

Table B6-8: PBR Sustainment and Other Capital Formula Results[31]

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Sustainment & Other Capital ($000)	$ 103,746					
LESS Capital Tracked Outside of the Formula:						
Insurance & OPEB ($000)	$ (1,672)					
Remaining Capital Applicable to PBR Formula	**$ 102,075**					
Average Number of Customers	840721	845495	850620	856001	861402	866681
% Change in Customer Additions		**0.57%**	**0.61%**	**0.63%**	**0.63%**	**0.61%**
Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
I-X Mechanism (1+I-X)		**101.81%**	**101.92%**	**101.84%**	**101.86%**	**101.80%**
Gross Remaining Capital Under PBR		$ 104,513	$ 107,165	$ 109,827	$ 112,576	$ 115,304
ADD: Capital Tracked Outside of the Formula		$ 1,543	$ 1,390	$ 1,313	$ 1,271	$ 1,508
Insurance & OPEB ($000)						
Total Remaining Capital Under PBR	**$ 103,746**	**$ 106,055**	**$ 108,555**	**$ 111,140**	**$ 113,847**	**$ 116,812**

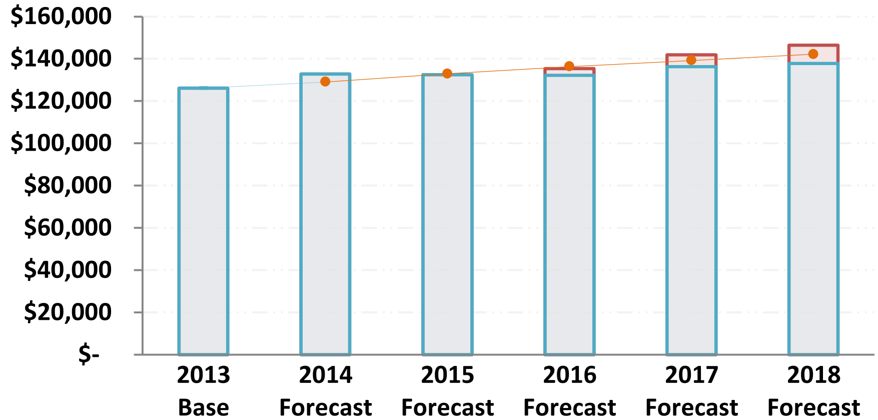
Total Capital Under PBR

Figure B6-3 provides a comparison of total capital under the PBR formula and the total capital forecasts over the PBR term.

With respect to the total capital forecasts, FEI presents two scenarios: a high construction cost forecast and a low construction cost forecast. The potential for a high construction cost forecast is driven by both an anticipated boom in pipeline projects projected in the later years and the related trend in higher construction costs. Both factors could considerably inflate construction costs particularly related to transmission system reinforcement projects and CPCN projects that require steel pipe and significant contract and engineering resources. As such, for the high construction cost forecast, FEI is projecting a potential 20 percent annual inflation rate in the last three years of the PBR Period as applied to transmission system reinforcement projects only. For the low construction cost forecast, FEI is projecting a 2 percent per year inflation rate (refer to Section C4.3.3 for further discussion).

[31] Refer to Attachment 1 to Appendix E1 for the forecast of average customers.

Figure B6-3: Comparison of PBR Total Capital vs Total Capital (TC) Forecasts ($000s)



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
TC High Construction Cost forecast	$126,197	$132,762	$132,553	$135,350	$141,918	$146,412
TC Low Construction Cost forecast	$126,197	$132,762	$132,553	$132,242	$136,230	$137,833
TC Under PBR	$126,197	$129,031	$132,921	$136,347	$139,173	$142,146

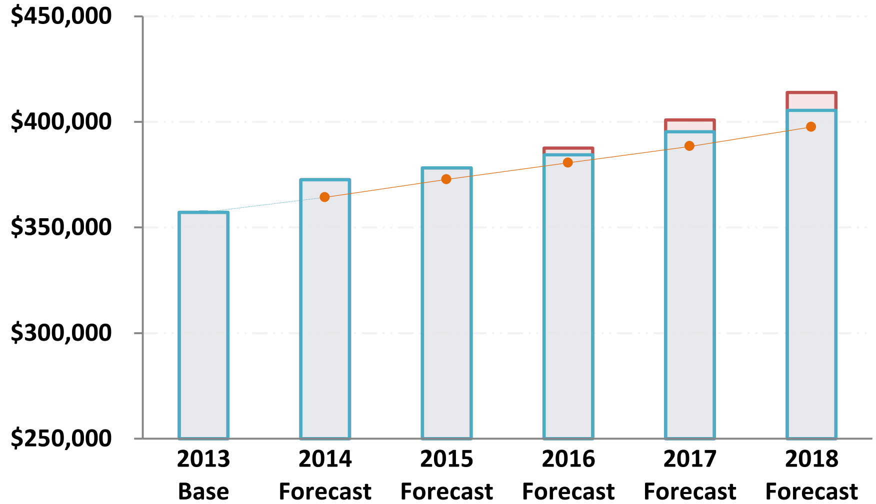
As Figure B6-3 indicates, the total allowed capital under PBR tracks closely with forecasted amounts. FEI believes this level of capital expenditure allowed under PBR provides a suitable incentive for FEI to find efficiencies for capital expenditures under both scenarios without raising concerns of compromising safe, reliable natural gas service or service quality.

6.2.5.3 Total O&M and Capital Under PBR

When the O&M and Capital allowed under PBR are examined separately, it is clear that the allowed expenditures under the PBR formula tracks more closely for capital than it does for O&M. While the capital allowed under the PBR formula is lower than the High Construction Cost Forecast in most years, it is also higher in some years than that forecasted when compared to the low construction cost scenarios. However, for O&M the allowed expenditure under the PBR formula falls significantly below what has been forecasted over the PBR Period.

When the O&M and Capital allowed under the PBR formula are examined together, the total is lower than what has been forecasted by FEI under both scenarios in every year of the PBR term. In other words, customers will benefit under the proposed PBR Plan since the resulting costs for customers under PBR are less than what FEI is forecasting they would be if rates were set under a Cost of Service model using the O&M and capital forecast in Sections C3 and C4 (see Section 7 below for further discussion on rate forecasts under PBR). Figure B6-4 provides a comparison of the total Capital and O&M allowed under the PBR formula and the total Capital and O&M Forecasts over the PBR term.

Figure B6-4: Comparison of Total O&M and Capital Expenditures Under PBR vs Total Forecast O&M and Capital Expenditures



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
TC High Construction Cost Forecast	$357,182	$372,623	$378,175	$387,585	$400,953	$413,965
TC Low Construction Cost Forecast	$357,182	$372,623	$378,175	$384,477	$395,265	$405,386
TC Under PBR	$357,182	$364,272	$372,709	$380,610	$388,363	$397,516

As Figure B6-4 indicates, total allowed expenditures under the PBR formula fall below the Low Construction Cost Forecast in every year of the PBR term. FEI believes that the proposed PBR Plan provides a strong incentive for FEI to find efficiencies for all expenditures throughout the PBR term.

6.3 *FLOW-THROUGH ITEMS AND EXOGENOUS FACTORS*

At various points in this section of the Application, FEI has made reference to elements in the proposed PBR Plan that will be flowed through in rates each year through the Annual Review process. This type of mechanism is used on non-controllable costs and revenues to ensure that customers pay actual costs in circumstances where the Utility does not control the level of expenditures or revenues. The rationale for addressing uncontrollable costs and revenues outside the PBR formula is addressed below with a discussion of the types of expenses and revenues that are beyond the control of the Company. The treatment of these items in the annual rate-setting process is the same as they were treated in the 2004 PBR Plan.

6.3.1 Addressing Uncontrollable Costs/Revenues Outside Formula

It is typical in the context of PBRs to treat uncontrollable factors outside of the PBR formula. As B&V states in its PBR Report:

> *"Since Z-Factors are beyond the control of management, it is typical to include a specific list of events that trigger the Z-Factor particularly where the cost changes represent cost changes that would be passed through as part of a cost of service proceeding. The standard list includes changes in taxes such as payroll or income tax changes, regulations that require increased capital or expenses associated with environmental or other regulatory decisions and specific events that may occur beyond the control of the utility."* (p.36)

B&V considers that the rationale for this treatment is sound. Including non-controllable costs within the formula can result in a windfall to either customers or the Company. Similarly, it is important to allow full recovery of these costs under a PBR plan, as the costs - being outside the control of management - are by definition prudently incurred costs of providing utility service that should be recovered from customers in the normal course.

B&V refers to all non-controllable factors as "Z-Factors", but the nomenclature differs from jurisdiction to jurisdiction. The AUC, for instance, adopts the term "Y-factors" for foreseeable uncontrollable expenditures, and uses the term "Z-Factors" only to describe those uncontrollable factors that are also unforeseen. FEI has similarly differentiated between factors that are foreseen and those that are not foreseen, although it does not generally use the term "Y-factors" when describing foreseen uncontrollable costs and revenues. There is no requirement to follow a specific terminology. Regardless of how the factors are characterized, the common element is that there is recognition that uncontrollable expenditures and revenues should not be subject to the PBR formula, otherwise it could result in windfalls for customers or the shareholder.

B&V agrees with FEI that the items identified below as flow through items and exogenous factors should be excluded from the proposed formula.

6.3.2 Flow-Through Expenses

A brief summary of the flow-through revenue and expense items is provided below.

Interest Expense

At the Annual Reviews a forecast of interest expense for the following year will be provided, and customers' rates for that following year will be determined on the basis of the forecast. The existing deferral account will record variances in long-term and short-term interest costs in accordance with the Commission-approved method for the account. Projected deferral account balances and forecasts of short term and long term interest rates and costs will be provided each year during the Annual Review process.

Return on Equity

With regard to the allowed ROE, the Commission approves both the ROE and the equity component within the capital structure. FEI will flow through any Commission-approved changes to the ROE and capital structure in the Annual Review process each year.

Taxes

Variances in property tax expenses, income tax rates, and other tax items are captured in deferral accounts. Projected deferral account balances and forecasts of tax expenses will be provided each year during the Annual Review process.

Pension and OPEB Expenses and Insurance Costs

These items are subject to deferral account treatment. Pension and OPEB expenses, and insurance expenses will be re-forecast at each Annual Review based on the most recent information provided by actuaries and FEI's insurance provider. Projected year-end deferral account balances will also be provided at the Annual Reviews.

Revenues

Revenues include amounts received from customers for the sale and delivery of natural gas, the provision of transportation service, revenues received under tariff supplements, and various other sources of revenue which are detailed in Sections C1 and C2. Natural gas usage rates are not under the control of FEI and customers make changes in the amount of natural gas they consume for various reasons.

Revenues will be forecast each year at the Annual Review and these revenues will be included in the determination of the revenue requirement and rates for the forecast year. Throughput-related revenue variations relating to residential and commercial customers (Rate Schedules 1, 2 and 3/23) will continue to be subject to the RSAM mechanism.

Depreciation and Amortization

As discussed in section B6.2.5, the 2014 Plan proposes to derive the annual regular capital expenditures by means of formulas. Similar to the treatment in the 2004 PBR Plan, the formula-based capital expenditures are carried forward in the rate base throughout the PBR term without adjusting the amounts to the actual spending levels (unless total capital expenditure spending deviates in any year by more than 10 percent from the formula amounts, as described in Appendix D4). Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include the formula-based capital expenditures as plant additions. The incentive power of the formula-based capital elements of the PBR Plan relates to finding ways to be more efficient in capital activities so that actual spending is less than the formula-derived amount. The accumulating differences between formula and actual spending give rise to variations in rate base carrying costs (i.e., return on rate base, depreciation expense and taxes).

Amortization of deferrals will be re-forecast at each Annual Review and actual amortization expense each year will equal the approved amount.

Rate Base other than Gas Plant in Service (from Capital Expenditures)

Section B6.2.5 describes how, as far as capital expenditures are concerned, the use of formula-based calculations will be limited to the regular capital expenditures. Larger projects developed as CPCNs will have their own BCUC approval process and will be added into rate base after they are approved and complete.

There are several other smaller components of rate base such as working capital and deferred charge balances other than those described above that are proposed to be forecast each year in the Annual Review process. These items include natural gas in storage and deferral account balances such as the MCRA, CCRA and RSAM (among others). These items cannot be reliably reduced to a formula and are strongly dependent on external factors such as commodity pricing and weather. Therefore FEI proposes to re-forecast the rate base balances each year in the Annual Review process.

6.3.3 Exogenous Factors

In the nomenclature of PBR, non-controllable and unforeseeable costs that flow-through to rates are referred to as Z-Factors. These factors were referred to in the 2004 PBR Plan as "exogenous factors". Consistent with the 2004 PBR Plan, FEI proposes that during the term of the proposed PBR Plan, customers' rates will be adjusted for the following exogenous factors that are beyond the control of the Company:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;
- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes, changes to cost of capital).

Exogenous or Z-Factor treatment of the above costs will ensure that customers pay only for the actual costs in circumstances where FEI does not control the level of expenditures. For further discussion of the rationale for exogenous factor treatment, please refer to the B&V PBR Report (Appendix D1), p.7.

6.4 *EARNINGS SHARING MECHANISM*

FEI is proposing to include an ESM as a component of the PBR Plan. The rationale for ESMs generally, and FEI's proposal to adopt an ESM design based on the 2004 PBR Plan, are addressed below.

6.4.1 Rationale for ESM

Sharing mechanisms are regulatory tools in a PBR that are designed to enhance the alignment between customer and company interests and share the risks and benefits of the PBR plan. They are also put in place to mitigate against unintended results of a new PBR plan such as excessive utility gains or losses. An earnings sharing mechanism is typically a backward-looking sharing mechanism in which a rate adjustment is provided if the actual earnings fall below or exceed a certain threshold (in some cases, the threshold equals the allowed ROE).

In general, two schools of thought exist in the regulatory economics literature regarding the use of an ESM. At one end of the spectrum is the assertion that ESM is contrary to the principles of incentive regulation as it decreases the incentive power of the PBR plan and imposes additional regulatory burdens and costs. The experts in the second group counter these claims by indicating that an ESM can allow for a utility's rates to better track realized costs which, along with other regulatory safeguards, mitigates the concern about excessive profits or losses, and that it is a fair approach for sharing the benefits of a PBR plan. In other words, an ESM amends some of the links between rates and costs that are decoupled under a PBR plan and helps to improve the allocative efficiency[32] of the plan[33]. The schools of thought also assert that ordinarily regulatory burden and costs related to ESM are minimal.

B&V is supportive of an ESM in the context of FEI's proposed PBR Plan. The B&V PBR Report articulates B&V's rationale for supporting the ESM:

> *"The concept of earnings sharing is based on assuring that an acceptable level of benefits are shared with consumers during the regulatory control period and that the utility is protected from unreasonably low returns in the event of unforeseen plan outcomes. The earnings sharing mechanism benefits both parties and does so without an overtly heavy hand of regulation."* (p.37)

6.4.2 Proposal for ESM

FEI is proposing to adopt an ESM based on the 2004 PBR Plan.

FEI's 2004 PBR Plan included an earnings sharing mechanism on a 50:50 basis between customers and the Company for earnings above and below the allowed ROE, as established each year by the Commission. As indicated in FEI's 2012-2013 RRA, the PBR Plan resulted in $135 million in gross savings ($67.5 million for the ratepayers and $67.5 million for the Company) during the 6 years of the PBR term over and above the embedded productivity factors. This significant amount of savings demonstrates that the 50:50 ESM design, along with other features of FEI's 2004 PBR Plan, provided incentives that were sufficiently powerful for

[32] Allocative efficiency is concerned with the optimal mix of goods and services and getting the most from scarce resources. Allocative efficiency is achieved when prices for goods and services are equal to marginal cost of production.

[33] Appendix D8-4 Lyon, Thomas P, 1996. "A Model of Sliding-Scale Regulation," Journal of Regulatory Economics, Springer, vol. 9(3), pages 227-247, May.

the Company to pursue substantial reductions in its costs. FEI's earnings sharing mechanism experience also indicates that the regulatory costs associated with its ESM have been generally minimal.

Based on the feedback received from various stakeholders and the positive experience with the previous earnings sharing mechanism, FEI believes that an earnings sharing mechanism continues to be beneficial and proposes an ESM similar to the 2004 PBR Plan with a 50:50 basis sharing between customers and the Company for earnings above and below the allowed ROE established for each year by the Commission.

Also, as in the 2004 PBR Plan, the amount of earnings to be shared will be projected at the Annual Review in the fall of each year and the customers' portion will be refunded or charged to customers by way of a rate rider. The actual earnings amount for sharing will be finally determined after the year end, with any differences between the projected and actual amount included in the calculation of the earnings sharing rider for the following year.

B&V supports FEI's decision to incorporate a similar ESM design to that employed in the 2004 PBR Plan. B&V's PBR Report states in that regard:

> *"The FEI plan included an earnings sharing mechanism that provided symmetric protection for all stakeholders. As a matter of regulatory policy, this reduces the risk of unfavorable outcomes for both FEI and stakeholders. Particularly, the ESM provided customers with real time benefits if FEI earned above the authorized return and assured customers that FEI would not be permitted to deteriorate financially such that system service, safety and reliability would not be compromised."* (p.46)

6.5 *EFFICIENCY CARRY-OVER MECHANISM*

FEI is proposing an efficiency carry-over mechanism (ECM) that incorporates some improvements from the ECM employed as part of the 2004 PBR Plan. The rationale for ECMs generally, and FEI's proposal to adopt an ECM, are addressed below.

6.5.1 Rationale for an ECM

The logic of incorporating an ECM is straightforward. For utilities operating under a fixed-term PBR, the value of the stream of savings to provide a payback of the Company's investments in efficiency improvements can only include those savings realized prior to the end of the term of the PBR. Therefore, the motivational power of incentives is highly dependent on the timing of the efficiency improvement gains. The reward for a utility is greatest when the efficiency savings are made in the first year of the PBR plan. The utility's incentive to pursue efficiency gains declines over the PBR term as the amount of time remaining to achieve a payback and return on efficiency investments becomes successively shorter. An ECM is a means of strengthening the incentive to pursue efficiency initiatives throughout the PBR term. The ECM does this by ensuring that the benefits of the efficiency gains are retained for a reasonable period after the PBR term. The benefit to customers of an ECM is that the greater efficiencies achieved throughout the PBR term become incorporated into rates going forward. A well-designed ECM decouples the link between the timing of efficiency gains and the PBR incentives and ensures that the stream of savings resulting from an investment in efficiencies will be allocated to help repay the investment regardless of how close the investment is to the end of the term of the PBR plan.

B&V's discussion on the rationale for an ECM is included in the PBR Report. B&V states, for instance, that "ECMs are an important factor in assuring that the efficiency incentive is not weakened as the end of the Regulatory Control Period approaches." (p.48) B&V further states:

> *"Using direct measures of capital and O&M efficiency gains and permitting those to carryover beyond the PBR period provides incentives for the utility to reduce costs based on an expected payback for the period of the carryover. The longer the period for carryover implies a lower required return for payback of the investment in efficiency while still being reasonably above the cost of capital so that customers also benefit beyond the reset of the regulatory control period."* (p.38)

As such, B&V supports the inclusion of an ECM in the PBR Plan, particularly with the enhancements discussed below.

6.5.2 Enhancing the Effectiveness of the 2004 PBR Plan ECM

FEI is proposing to include an ECM based on the 2004 PBR Plan, but with significant enhancements.

The 2004 PBR Plan included an ECM under which the accumulated capital benefits at the end of the term were phased-out by declining factors of 2/3 in the first year after the plan expiry and 1/3 in the second year after. B&V and FEI are of the view that the objective behind this mechanism was sound. B&V states in its PBR Report, for instance:

> *"While not approving the original FEI proposal [for the 2004 PBR Plan], the BCUC correctly recognized the need for an incentive to continue beyond the end of the plan and approved a mechanism to reflect the continuing benefit from such improvements. The logic behind this incentive is quite simple. When capital and other costs are rebased at the end of the control period all of the benefits from capital and savings on O&M immediately flow through to customers in lower rates. This means that investments in efficiency that have a longer payback period than the remaining time under the PBR plan would be discouraged because the utility could not expect a full payback on the investment before the savings were appropriated for customers. Unlike FEI, the FBC Plan did not include an ECM. Since capital was not included in the PBR, the annual review required by the exclusion would no longer be a necessity.*

> *Nevertheless, the ECM is a critical component of a PBR plan if the goal is to maximize efficiency during the pendency of the Plan."* (p.47)

While the FEI 2004 PBR Plan mechanism increased the overall incentive power of the plan, it did not provide the optimal balance of incentive power between O&M and capital efficiencies over the whole term of the PBR. Under the approved capital-only approach, the incentive power in the first and early years of the PBR was higher than the later years of the PBR plan. In addition, the 2004 PBR ECM did not recognize the permanent efficiency gains that were achieved in O&M expenditures.

The effectiveness of the 2004 PBR Plan ECM can be enhanced in two ways:

1. by using a rolling carry-over approach; and
2. by including the O&M savings in the carried-over efficiencies.

Under a rolling ECM, efficiency gains are carried over for a specific number of years (5 years in the case of FEI's proposed term) following the year in which they occurred. The major advantage of a rolling ECM over other efficiency carry-over approaches is that it eliminates the timing issue from the decision making process of efficiency improvement investments. That is, the incentive power of PBR will remain the same for the entire PBR term. Also the addition of O&M savings is an essential part of an ECM model in order to maintain the incentive balance between capital and O&M expenditures. The equal treatment of cost savings between capital and O&M expenditures encourages the utility to seek the most efficient combination of these expenditure types throughout the PBR term.

Further, for O&M expenditures, the total efficiency gains are measured as the variance between actual expenditures and formula-based forecasts on a year-to-year incremental basis to avoid rolling forward of temporary savings. Capital expenditure savings however tend to be more discrete between the years and savings in one year implies a reduction in the costs of financing and other carrying costs rather than a permanent reduction in future capital spending. Therefore only a specific percentage of capital savings representing the avoided capital financing and carrying costs should be included in the ECM model. Similar to the 2004 PBR Plan, this percentage is identified as the "rate base benefit factor" in FEI's ECM model and is applied to the capital savings to account for average avoided financing and carrying costs (cost of capital, taxes and depreciation) in annual revenue requirements associated with the cost of service incurred by plant additions added to rate base.

Based on the above-mentioned principles, FEI proposes to balance the PBR incentives and improve the effectiveness of the 2004 PBR Plan ECM, by implementing a 5 year rolling-forward of the incremental O&M and capital savings calculated as the sum of:

1. Variance of current year formula-based O&M and actual O&M less cumulative O&M savings from prior years of the PBR Plan; and
2. Current year plant additions savings relative to current year allowed plant additions derived from the PBR capital formula multiplied by a rate base benefit factor of 15 percent.

The rate base benefit factor is representative of the avoided revenue requirements from reduced capital expenditures, which on average equal approximately 15 percent of the amount of the capital cost saving. The components that make up the avoided revenue requirements are the return on rate base, depreciation expense and associated taxes, sometimes referred to as rate base carrying costs. The calculations supporting the proposed 15 percent rate base benefit factor as well as an illustrative example of the proposed rolling ECM are provided in Appendix D6.

The effect of the 50/50 Earnings Sharing Mechanism extends beyond the PBR Plan term in the calculation of the ECM benefits that go to the customers through rate rebasing and the other half that is available to the Company through the rolling efficiency carry-over mechanism. This means the ECM phase-out of savings has the same 50:50 earnings sharing effect as the ESM does for the O&M and capital efficiencies during the PBR term.

B&V supports the proposed ECM because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity occurring in the later years of the PBR Plan. By permitting a carryover to match the initial period of the plan, the utility invests in measures throughout the plan period and there is no disincentive as the PBR Plan comes to an end.

6.6 *SERVICE QUALITY INDICATORS*

Service Quality Indicators (SQIs) are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality. B&V's discussion of SQIs appears at p.11 of its PBR Report (Appendix D1). SQIs were a key component of the 2004 PBR and FEI proposes to continue with this feature, with appropriate updates to the SQIs themselves.

The SQIs' design and targets have been unchanged since 2004 and FEI believes that based on an evaluation of the feedback received during the last 10 years it is appropriate to review and update the SQI elements. The 2014 Plan proposed SQIs include a number of new additions and replacement of some indicators with more relevant ones. The table below summarizes the proposed SQIs.

Table B6-9: Proposed 2014 PBR Improved SQIs

Performance measure	Indicator	Benchmark
Emergency response time	Percent of calls responded to within one hour	95%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%
Telephone service factor (Non Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%
First contact resolution	Percent of customers who achieved call resolution in one call	78%
Billing index	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%
All injury frequency rate	Informational indicator - 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	---
Public contact with pipelines	Informational indicator - 3 year rolling average of number of line damages per 1,000 BC One Calls received	---
Customer satisfaction index	Informational indicator	---

FEI will report to the Commission and stakeholders at the Annual Review to allow a comparison of the performance of the Company against the targets set for each of the SQIs. A full discussion of the improved SQIs is included in Appendix D7 to this Application.

6.7 *MID-TERM REVIEW AND OFF RAMPS*

B&V has confirmed that the majority of PBR plans include provisions that protect the customers and the utility against the potential unintended or unexpected outcomes that may occur during the plan's term. These regulatory provisions may vary from modification of a particular element of the PBR design (regulatory review, also known as re-opener) to complete regulatory review or termination of the plan (also known as off-ramps). Similar to the 2004 PBR, FEI proposes a Mid-term Assessment Review of the PBR Plan and an off-ramp provision as the PBR's safeguard mechanisms. A discussion of each of the mentioned items follows.

6.7.1 Mid-term Assessment Review

A PBR Mid-term Assessment Review provides an opportunity for all the stakeholders to review the outcomes of the PBR and suggest adjustment to certain plan parameters (if required). The Mid-term review as part of the third Annual Review is intended to be a "checkpoint" to permit stakeholders to review the performance over the first three years and to address specific and discrete flaws with an otherwise workable plan. This limitation is important. Off-ramps exist for more fundamental flaws with the PBR Plan as a whole, and short of triggering those off-ramps, the PBR Plan should be allowed to play out unless there is consensus that an element of the plan is capable of being improved for the mutual benefit of stakeholders.

The proposed Mid-term Assessment Review will be held prior to the end of the third year (2016) of the term as part of the third Annual Review. Similar to the 2004 PBR Plan, the terms of reference of the Mid-term Assessment Review will be two fold:

1. If any one (or more) particular element of the PBR Plan appears to be inducing unintended outcomes or results in continuous material changes to service quality, then stakeholders will work to identify a change that can address that element and put it forward to the Commission.
2. If the results of operating under the PBR Plan have caused financial distress and, if so, to implement a change (an example might be significant inflationary pressures on sustainment capital expenditures that are not reflected in the province-wide CPI or AWE measures).

6.7.2 Off-ramp Provision

Whereas the Mid-term review is intended to be a "checkpoint" to permit stakeholders to address specific and discrete flaws with an otherwise workable plan, an "off-ramp provision" is a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances. FEI is proposing both financial and non-financial triggers for the off-ramp provision. B&V considers that the inclusion of automatic quantitative re-openers or off ramp provisions is an improvement over the past FEI and FBC PBR plans:

> *"Both FEI's and FBC's Plans did not include any quantitative reopener[34] or off-ramp provisions. Under the annual review provision, FEI and FBC retained the right to request a change or termination of the Plan if there were unacceptable outcomes associated with the Plan. This provision does not represent the best approach to addressing serious issues with a PBR plan."* (p.46)

The proposed financial and non-financial triggers are discussed below.

6.7.2.1 Financial Trigger

Earnings-based trigger mechanisms, which are triggered if the actual ROE of the utility differs significantly from its approved ROE, is the most common form of off-ramp provisions. FEI is proposing that the PBR Plan be reviewed if the post-sharing achieved ROE of the Company exceeds or drops below the allowed ROE by 200 basis points in any single year of the PBR term.

[34] B&V is referring to an automatic reopener.

Finding the right balance between maintaining the PBR incentives and safeguarding the ratepayers and the Company is essential in design of the earnings-based off-ramps. The trigger point (the variance between earned and approved ROE) should be substantial enough to ensure that PBR's incentive powers are maintained (this is particularly important for a single year trigger point) and at the same time small enough to safeguard against potential excessive profits or losses. FEI believes that its proposed 200 basis point trigger achieves the appropriate balance[35]. B&V has discussed the considerations that go into the selection of an off-ramp in its PBR Report at p.9.

6.7.2.2 Non-Financial Triggers

In addition to the earnings based off-ramp provision, FEI proposes a number of non-financial SQIs to assist with the review and analysis of annual performance. The SQIs will provide a framework for determining whether there is a need for a complete regulatory review of the PBR Plan during the mid-term assessment review. Failure to meet one (or more) SQI benchmarks does not necessarily constitute unacceptable performance. Reasons provided by the Company as to why certain service quality indicator benchmarks were not met will be taken into account, recognizing that variances in performance may occur due to random events or events beyond the full control of FEI. Triggering of the off-ramp provision would be warranted only if there is sustained serious degradation of the SQIs.

6.8 ANNUAL REVIEW

The 2004 PBR Plan included an Annual Review which provided the Commission, interveners and interested parties an opportunity to review the Company's performance during the prior year. The Annual Review also provided these parties with forecasts and determined the delivery rates for the upcoming year. The Annual Review was a successful tool in communicating the Company's performance and activities, and also for understanding the issues and challenges facing the Company.

Based on the effectiveness of the past annual reviews, the FEI proposes to continue the Annual Review process for this PBR Plan. Each year, the Annual Review will present the current year's projections and the upcoming year's forecasts for a number of key measures, including:

1. Customer growth, volumes and revenues;
2. Year-end and average customers, and other cost driver information including inflation;
3. Expenses (determined by the PBR formula plus flow through items);
4. Capital expenditures (as determined by the PBR formula plus flow through items);

[35] The 2004 PBR Plan had a trigger mechanism of 150 basis points (after earnings sharing) above or below the allowed ROE that was not an automatic off-ramp. It was open for parties to request a Commission review of the 2004 PBR Plan if this threshold was exceeded but the 150 basis point threshold was not exceeded in the six-year term.

5. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
6. Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year
7. Service Quality Indicator results; and
8. Any proposals for funding of incremental resources in support of customer service and load growth initiatives.

FEI expects that the Annual Review regulatory process will generally include a workshop, one round of IRs from the Commission and Interveners, letters of comment and a Commission determination of rates.

What follows is Table B6-10, a summary comparison of FEI's current PBR Plan proposal and the 2004 Plan.

1 **Table B6-10: FEI PBR Plans Comparison**

Item	2004 PBR Application	2014 PBR Application
Term	Five year term proposed. A four year term from 2004-2007 was approved after NSP, Two year extension to 2009 approved later.	A five year term from 2014-2018 is proposed
Inflation Factor (I-Factor)	A forecast of BC-CPI was used as the I-factor.	A weighted average of BC-CPI as well as Average Weekly Earnings will be used to determine inflation forecasts.
Productivity Improvement Factor (X-Factor)	Approved adjustment factors (i.e. X-Factors): 50% of CPI 2004 and 2005, 66% from 2006 to 2009.	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M was approved. 2003 approved O&M used as a base, escalated each year by customer growth and inflation less the adjustment factor (i.e. I-X). No O&M rebasing during the PBR term; however formula amounts were trued-up going forward for actual customer growth.	Same O&M formula structure & annual O&M escalation proposed as in 2004 PBR. 2013 approved O&M expenditures (with adjustments) proposed as the base. No rebasing but same customer true-up as in 2004 PBR.
Controllable Expenses – Capital	Base capital expenditures in each year were based on forecast net customer additions for growth capital and forecast average number of customers for other base capital. Capital costs were also escalated annually by BC-CPI less the adjustment factor. CPCNs (>$5 million) were outside the formula. No capital rebasing during the term however formula amounts were subject to true-up going forward for actual customer growth.	Same capital formula structure and escalation as in 2004 PBR. Cost driver for growth capital changed to service line additions. Same treatment for CPCNs and customer count true-up as in 2004. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%.
Controllable Expenses - Other Revenue	FEVI Wheeling Agreement and SCP third party revenues forecast each year at the Annual Review. The Late Payment revenue was adjusted by inflation less the adjustment factor.	All Other Revenue items to be reforecast annually.
Exogenous Factors	These factors included judicial, legislative or administrative changes, orders or directions, catastrophic events, bypass or similar events, major seismic incidents, acts of war, terrorism or violence, changes in accounting principles, standards or policies, and changes in revenue requirements due to Commission directions.	Same exogenous factors as in the 2004 Plan.
Flow Through Expenses & Revenues	Revenues and non-controllable expenses (such as property taxes, interest costs, return on equity, pension/OPEB costs, insurance costs, depreciation rate changes, amortization of deferral accounts and others) were reforecast annually and flowed through in rates in the Annual Review process.	Same flow-through expense items and treatment as in 2004 PBR. Rate Schedule 16 O&M is a new item for annual reforecasting and flow-through treatment.

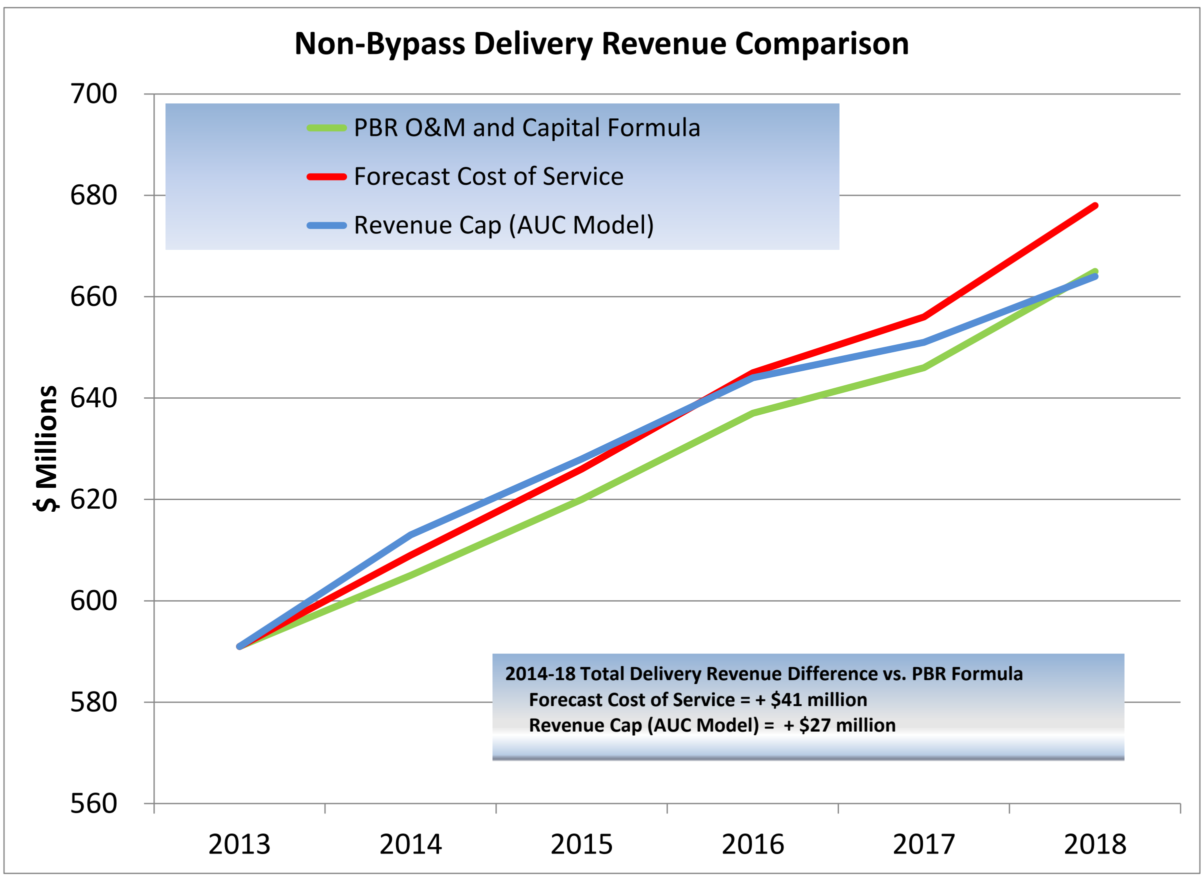
Item	2004 PBR Application	2014 PBR Application
Earnings Sharing Mechanism	A 50/50 earnings sharing mechanism was applied during this PBR. The difference between the allowed and actual ROE was shared equally between customers and shareholders.	Earnings sharing will be the same as in 2004 PBR at 50/50 earnings sharing above and below the approved ROE.
End of Term Efficiency (Efficiency Carry-Over Mechanism)	At the end of the PBR term, cumulative capital savings were returned to customers over a two year period, with one third being refunded in the first year and two thirds refunded in the second year.	An enhanced ECM is proposed that considers capital and O&M benefits on a rolling five year basis.
Service Quality Indicators	A set of 10 SQIs and 2 directional indicators. 3 of the 10 SQIs were recognized as being susceptible to external influences beyond the Company's control and were to be given less weight.	An improved set of 10 SQIs is proposed dealing with emergency response, customer service (telephone service, billing), employee safety and meter exchanges. 3 of the 10 SQIs are considered to be informational indicators.
Mid-term Review and Off Ramps	A midterm assessment review was held prior to the end of the third year of the PBR (2006). Any party could request a Commission review of the PBR Plan if the achieved ROE (after earnings sharing) was more than 150 basis points above or below the allowed ROE.	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	An annual review was conducted at the end of each year to provide a report on company performance.	An annual review is also proposed for this PBR.

7. DELIVERY REVENUE FORECASTS UNDER PBR

FEI has looked at three delivery revenue[36] scenarios for the years 2014 through 2018. They are:

- FEI's PBR Plan Proposal (green line in the graph below);
- Cost of Service using the O&M and capital forecasts included in Sections C3 and C4 using forecast inflation (red line)
- A delivery revenue cap per customer scenario using the same assumptions as the PBR Plan Proposal (blue line).

Figure B-5: Non-Bypass Delivery Margin Comparison



The differences in required revenues in the graph above reflect the customer benefit of the proposed PBR formula as compared to either the cost-based approach of setting rates or a delivery revenue cap per customer approach. FEI's PBR Plan results in non-bypass delivery

[36] The chart compares non-bypass delivery revenues under the various scenarios, which comprise more than 90% of FEI's total delivery revenues. The analysis adopts non-bypass delivery revenues as the basis of comparison since these represent the customer classes that receive rate adjustments through revenue requirement applications. Bypass and special contract revenues are excluded as they do not receive RRA rate increases or decreases.

revenues that are lower by an estimated $41 million over the five-year period than the Cost of Service scenario using the forecast O&M and capital expenditures included in this Application. In 2018, the fifth year of the PBR Plan, the non-bypass delivery revenues under the PBR are approximately 2 percent lower than those under the forecast Cost of Service scenario. The PBR Plan also produces delivery revenues that are lower by $27 million over the five-year period than a revenue cap model (similar to the type approved by the AUC in its Decision 2012-237).

In addition, the PBR Proposal offers both regulatory efficiencies and the opportunity for lower rates for customers through the ESM as compared to the Cost of Service approach. The PBR Proposal offers greater flexibility in addressing uncontrollable matters as compared to the delivery revenue per customer approach.

8. CONCLUSION

B&V and FEI regard FEI's proposed PBR Plan as capturing the best elements of the past plans, while improving upon some of the aspects that could work better. B&V's conclusion in its PBR Report sums up this view:

> *"FEI's and FBC's past PBR Plans provide valuable perspectives in the evolution to its currently proposed Plan. It is reasonable to conclude that no plan will be perfect in all respects (and thus the importance of settlement in satisfying the public interest). Subsequent plans should improve on the elements of the plan that were deficient and continue those elements that were successful. In particular, FEI and FBC should change the basis for determining the I-Factor and the ECM method. In addition, retaining the successful elements of the plan such as the ESM and the transparency created by the annual review are examples where the prior Plan benefited stakeholders. Further, by recognizing deficiencies of other plans as discussed above FEI and FBC will avoid implementing a Plan that does not represent the best interest of stakeholders. Neither excess earnings nor deficient earnings benefit stakeholders. The Plan should meet the goals of providing just and reasonable rates and a reasonable opportunity to earn the allowed return. If those goals are met all stakeholders benefit from a financially sound utility that provides reasonably priced services and does so with a safe, efficient and reliable system".* (p.47)

C: FORECASTS FOR THE PBR PERIOD

This section sets out the Company's forecasts for the PBR Period as follows:

- Section C1 provides FEI's forecast demand for natural gas and resulting revenues and margin at existing rates.
- Section C2 provide FEI's forecast of other revenue.
- Section C3 provides FEI's historical and forecast O&M with supporting departmental summaries and drivers.
- Section C4 provides FEI's historical and forecast capital expenditures by major capital category.

1. DEMAND FORECAST, REVENUE, AND MARGIN FROM EXISTING RATES

1.1 INTRODUCTION AND OVERVIEW

This section provides a discussion of the demand for natural gas, comprised of natural gas sales and transportation volumes forecast for 2014 through 2018. Tables and financial models to support the demand forecast are included in Appendix E2 and E3. The yearly forecasts beyond 2014 provided in this section are FEI's best current estimates. However, they should be considered as background information only, since they will be updated as part of the annual rate setting process. Under the proposed PBR Plan, customer accounts and the use per account used to derive rates for each of the forecast years will reflect the best information available at the Annual Review held prior to the commencement of each calendar year.

The forecast of demand for natural gas[37] is derived from the following three inputs:

- The forecast number of customers and customer additions by customer class; and
- The forecast average Use Per Customer (UPC) by customer class; and
- The demand from Industrial customer classes as determined by the annual Industrial Survey

[37] These inputs were used to derive the demand for all rate schedules, excluding the incremental volumes which were forecast using a separate methodology, described in Appendix H, with the results included in Section C1.4.6.

The revenues and margin described in this section are calculated by multiplying the forecast demand by the existing delivery rates. Therefore, they represent the revenues and margin at existing (2013) rates.

FEI is expecting to experience a slight increase in consumption over the PBR Period. 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 2014. The remainder of this chapter is organized as follows:

- Section C1.2 - Overview of Total Demand Forecast
- Section C1.3 - Underlying Forecast Methodology
- Section C1.4 - Demand Forecast and Revenues

1.2 OVERVIEW OF TOTAL DEMAND FORECAST

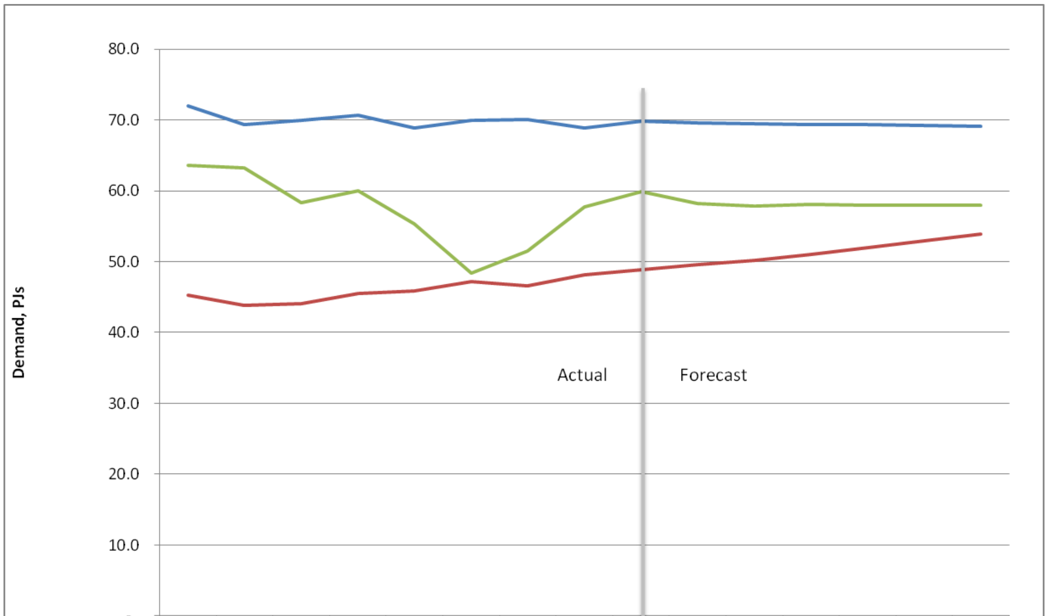
Below, the Company provides an overview of the demand forecast for 2014, and the forecast demand for 2015 through 2018 using current data. The detailed explanations for these forecasts are provided in subsequent sections.

The following Table C1-1 shows FEI's total energy demand forecast for the PBR Period, and illustrates that the Company is expected to experience a slight increase in consumption. It should be noted that the forecast demand in this table does not include new customer additions or new energy demand related to CNG and LNG service that is presented in Section C1.4.6 and Appendix H. However, existing natural gas for transportation customers under Rate Schedule 6 have been included as part of the Industrial customer demand.

Table C1-1: Forecast Total Energy Demand, PJs

	2014	2015	2016	2017	2018
FEI					
Residential	69.5	69.4	69.3	69.2	69.1
Commercial	50.2	51.1	52.0	52.9	53.9
Industrial	57.9	58.1	57.9	57.9	57.9
Total	**177.6**	**178.6**	**179.3**	**180.1**	**181.0**

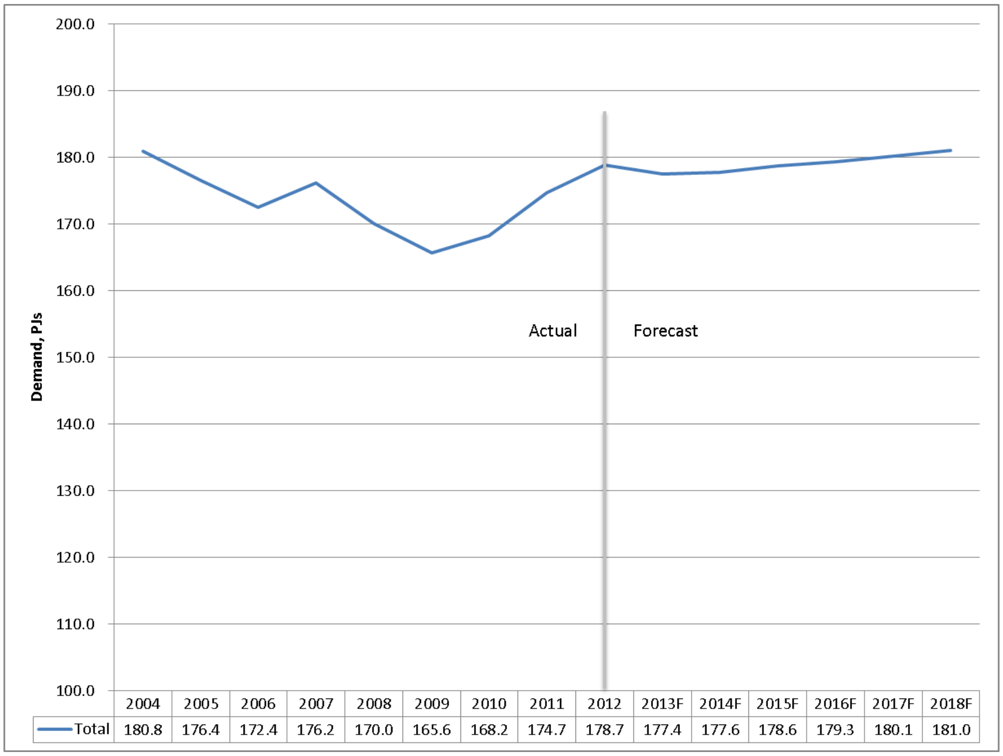
Figure C1-1: Total Energy Demand by Rate Schedule Group



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	72.0	69.3	70.0	70.6	68.8	70.0	70.0	68.9	69.8	69.6	69.5	69.4	69.3	69.2	69.1
Commercial	45.2	43.9	44.1	45.5	45.9	47.2	46.6	48.1	48.9	49.6	50.2	51.1	52.0	52.9	53.9
Industrial	63.6	63.3	58.3	60.0	55.3	48.4	51.5	57.7	59.9	58.2	57.9	58.1	57.9	57.9	57.9

Figure C1-1 above shows an increase in demand in the commercial rate classes, partly offset by a decrease in demand in the residential rate class, while demand in the industrial rate classes is relatively stable over the PBR Period.

Figure C1-2: Total Energy Demand



As shown in Figure C1-2 above, the overall demand has increased since 2009. The increase is from the commercial and industrial rate schedules, which have offset the continued decline in the residential UPC.

The slight increase in total throughput has a positive impact in reducing delivery rates, all else equal, for 2014 through 2018.

As shown in Table C1-2 below, net customer additions are expected to increase slightly in 2014 through 2018. Forecast additions are in line with those seen in 2009 and 2011 but lower than the high seen in 2010.

Table C1-2: Net Customer Additions

	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential	4,822	6,824	4,994	4,475	4,316	4,594	4,955	5,085	4,972	4,806
Commercial	299	141	417	272	315	388	373	358	372	367
Industrial & Transportation	-31	-96	-67	-4	0	0	0	0	0	0
Total Net Additions	**5,090**	**6,869**	**5,344**	**4,743**	**4,631**	**4,982**	**5,328**	**5,443**	**5,344**	**5,173**

The following Table C1-3 describes the existing rate schedules included in each of the three rate schedule groups (Residential, Commercial, Industrial).

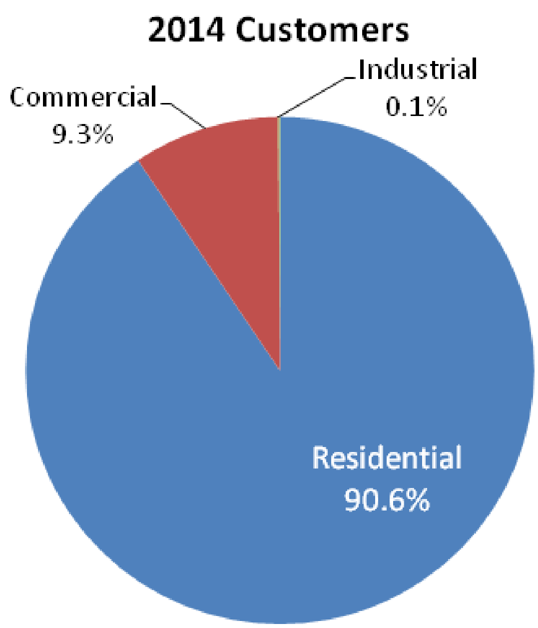
Table C1-3: Rate Schedule Classification*

	Mainland
Residential	1
Commercial	2, 3, 23
Industrial	4 ,5, 6, 7, 22, 25, 27

* Note: Rate Schedule 16 has not been included because it is a supply offering for LNG and not a delivery service or transportation rate schedule like Rate Schedule 23 or Rate Schedule 25, for example.

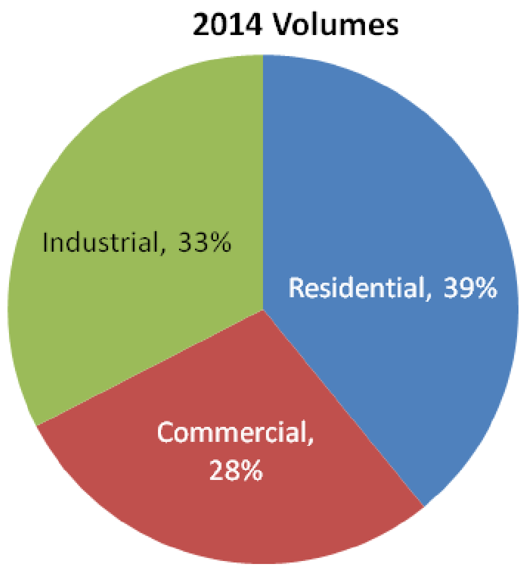
For 2014 90.6 percent or 768,622 of FEI's customers are forecast to be residential. 9.3 percent, or just over 79,100 customers, are in the commercial rate schedules while 877 are in industrial rate schedules. The split is shown in Figure C1-3 below:

Figure C1-3: Total Customer Split between Rate Groups



The forecast energy demand by rate schedule group for 2014 is shown in Figure C1-4 below. The split between residential, commercial and industrial energy demand for 2014 remains consistent with prior years. The residential and industrial rate classes account for 39 and 33 percent, respectively, while the commercial rate classes account for the remaining 28 percent.

Figure C1-4: Total Demand Split between Rate Schedule Groups



1.3 *FORECAST METHOD*

The forecasts summarized above were prepared according to the method used in prior RRAs. The method involves two major steps:

1. Forecast account additions, use rates and industrial demand using methods that are consistent with past forecasts. These methods result in demand forecasts for each rate class. The aggregate energy forecast is the summation of three separate demand forecasts as follows:

    - The forecast **Residential Energy Demand** is the product of the normalized forecast residential use rate and the residential accounts (including account additions).
    - The forecast **Commercial Energy Demand** is the product of the normalized forecast commercial use rate and the commercial accounts (including account additions), for each commercial rate schedule.
    - The forecast **Industrial Energy Demand** is the forecast demand reported through the annual Industrial Survey.

2. Compare the independently developed forecast with historical data. Through this comparison the forecast for gas usage by our customers is verified. The tables and figures presented in Section C1.4 all show the historical values recorded by the Company along with the forecast values for 2014 through 2018.

The following sections discuss the method used to prepare the demand forecast. The Company believes it is reasonable to use the existing forecast method that has been reviewed and accepted internally, and by the BCUC in past regulatory proceedings, including in the 2012-2013 RRA.

1.3.1 SAP Account Adjustment

FEI's new CIS, which became operational as of January 1, 2012, has enabled a more accurate method of counting customers.

In the previous CIS, the number of customers was determined at month-end using an algorithm that counted the number of services (meters) that were installed at a premise, where:

- The meter was not disconnected during the entire reporting period (month); or,
- The meter was disconnected during the reporting period, but a customer was attached to that premise for at least one day in that reporting period.

This means that to be considered a customer, the service had to be active at some point during the month.

In the new SAP-based CIS, the algorithm for determining the number of customers is to count the number of valid contracts (for natural gas service) that are in effect on the reporting date (which can be any day of the month). For purposes of reporting monthly customer counts, the FEU use the mid-month report (based on the 15th of the reporting month).

A customer in the new SAP-based CIS is defined as a valid contract to provide natural gas service. This definition results in a different customer count from that of the previous CIS in those situations where a premise becomes vacant or meters are disconnected during the reporting period. Under the new system these vacant premises or meter disconnects no longer have a valid contract as of the day the premise becomes vacant or the meter is disconnected. This is in contrast to the previous CIS where there was still an installed meter that received service during the reporting period. For example, if a customer was disconnected on January 10, under the previous CIS they would be reported as a customer for the month of January (as a meter would have been attached to that premise for at least one day during the month of January). Under the new CIS, however, they would be excluded.

Further discussion of this change in customer counts was provided in a letter from the FEU filed with the Commission on January 28, 2013. The letter can be found in Appendix E4.

The mathematical result of a decrease in the number of customers with no change in delivery volumes is an increase in the use per customer (volumes divided by number of customers equals use per customer) in residential and commercial rate classes. These one-time increases are not indicative of recent trends and were not included in the calculation of the forecasted use rates.

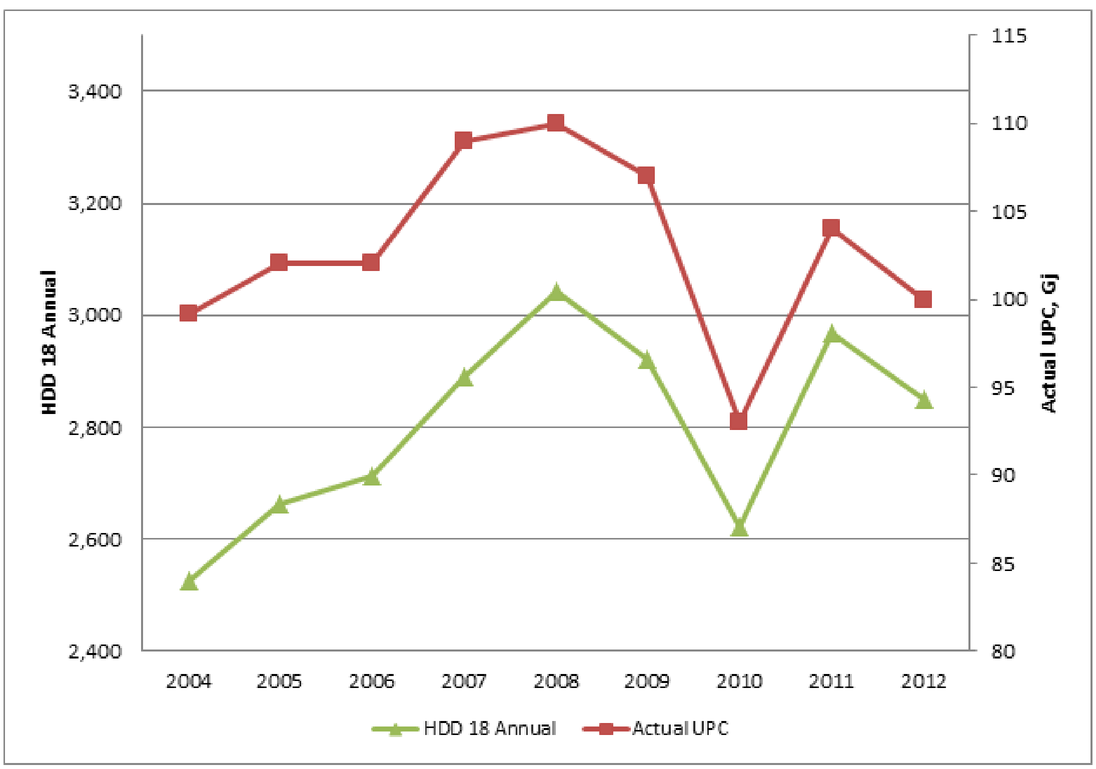
1.3.2 Residential and Commercial Average Use Per Customer Forecast Methodology

The forecast UPC is one of two key inputs for both the residential and commercial demand forecast. The forecast UPC is multiplied by the total customer accounts in each rate schedule to determine the demand in those rate schedules. The forecast of average usage per customer is based upon an analysis of weather normalized consumption data. Normalized UPC forecasts are developed for the residential and all commercial rate classes.

Normalization is the process that allows us to compare use per customer in different years irrespective of the weather. Normalization essentially removes the weather as a factor from use per customer, allowing us to compare UPC rates from different years.

The following figure compares the actual residential demand with the annual heating degree days (HDD). Higher HDD totals indicate a colder year. As can be seen, the residential demand closely follows weather patterns.

Figure C1-5: Annual HDD Correlates Well to Actual Residential UPC

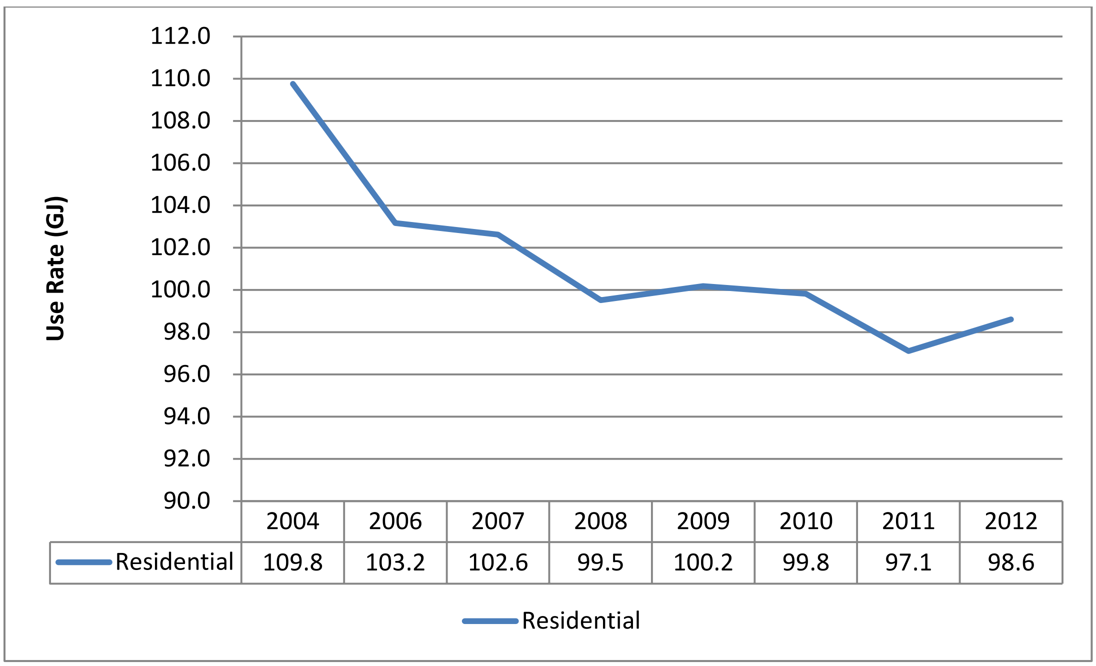


In colder years, such as 2008, both total HDDs and residential demand increases. In warmer years, such as 2010, both HDDs and residential demand decreases.

Given the influence of the weather, it is not possible to make an accurate prediction of the future use rate based on the historical actual use rate. We need to first normalize the UPC by removing the weather effect. Consistent with past practices and industry standards, and dating back to the 1992 RRA, which was approved by Commission Order G-63-92, FEI uses the previous 10 years of weather data for normalization. Once this is done, the normalized UPC may reveal other trends that are present in the data, such as reduced consumption resulting from improved appliance efficiency.

The following figure shows the normalized UPC for the Lower Mainland region of FEI.

Figure C1-6: Normalized Use Rate Per Customer for the Lower Mainland



From the figure above we can see that there is a clear and consistent downward trend in use per customer irrespective of annual weather. The exception is in 2012 when the conversion to the new CIS had the impact of increasing the reported UPC. In rate schedules where a consistent trend is not identifiable a three year average is used.

The Company believes that the drivers lowering the UPC include, but are not limited to, efficiency improvements, changes in building stock, changes in appliance uptake and switching between energy sources (gas/electric). Efficiency improvements include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and, more generally speaking, building shells. Efficiency improvements are driven by a number of factors, such as technological advances, construction of smaller, less energy-intensive multifamily dwellings, natural gas prices, public policies and programs and the state of the economy. Efficiency improvements are also driven by FEI's EEC programs. Since the Company's EEC programs have significant levels of funding, it is reasonable to assume that these programs will impact average UPC over the forecast period. In 2011 and 2012 the impact was estimated to be a 0.09 and 0.26 GJ decline respectively in residential average UPC. In 2013 the impact is forecast to be a 0.64 GJ decline in residential average UPC. While EEC savings are not a direct input into the forecast model, their effect is implicit in the declining UPC trends.

1.3.3 Residential Customer Additions Forecast Methodology

Residential customer additions and the existing residential customer totals are the second key input in the residential demand forecast. The customer count (including additions) is multiplied by the average use per customer to form the residential demand forecast.

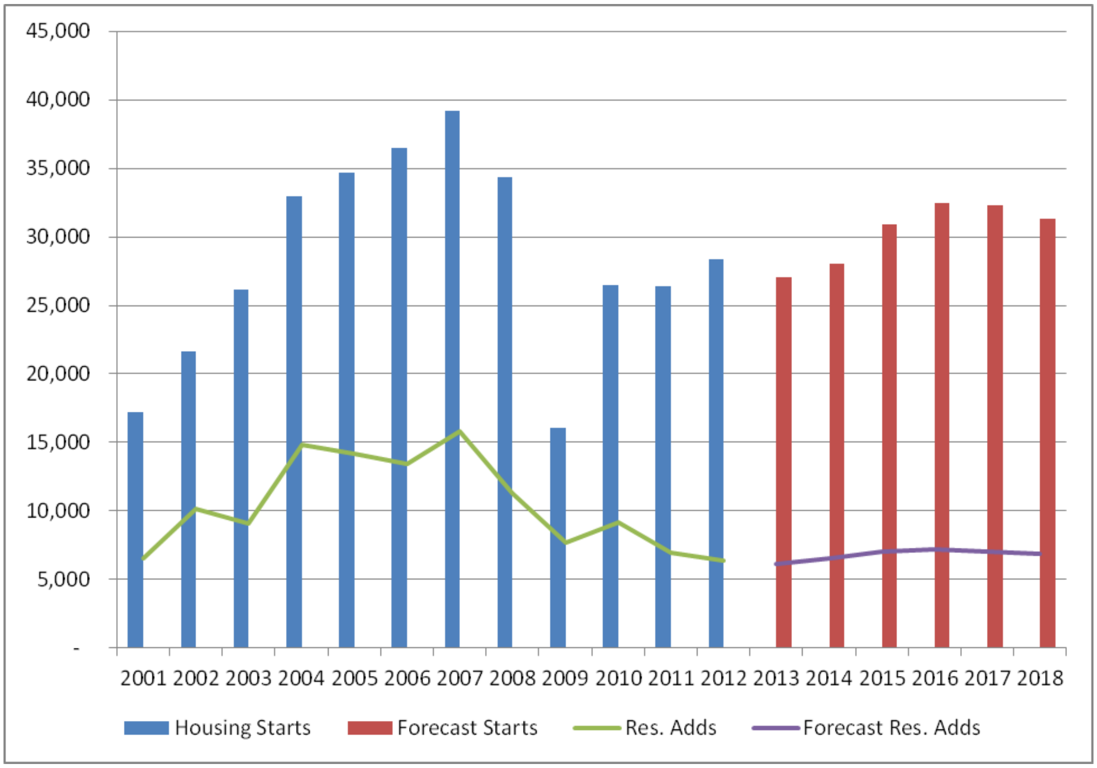
In order to forecast customer additions, we continue to use the housing starts forecasts from the CMHC and the Conference Board of Canada (CBOC). The forecast provides separate single family and multi-family residential estimates.[38]

Consistent with the 2012-13 RRA, the residential net customer addition forecast consists of a single and multi-family dwelling forecast. These two forecasts are based on our own internal customer mix for these dwellings as well as the CBOC forecast for growth in these two housing types. Once the separate forecasts are completed the accounts are combined for the two housing types and become the Rate Schedule 1 residential accounts forecasts.

The following chart shows the relationship between the total housing starts and historical Rate Schedule 1 net customer additions for the period 2001 to 2012. The forecast starts and customer additions are shown for 2013-2018.

[38] Conference Board of Canada Long Term Housing Starts Singles Forecast dated November 16, 2012 and Conference Board of Canada Long Term Housing Starts Multiples Forecast dated November 16, 2012, refer to Appendices E1 and E2.

Figure C1-7: Customer Additions Correlate Well with Housing Starts



The above figure demonstrates the continued strong correlation between housing starts and net residential customer additions. The correlation statistic is over 90 percent. For this reason the CBOC housing starts forecast is an appropriate proxy of the Company's customer additions forecast.

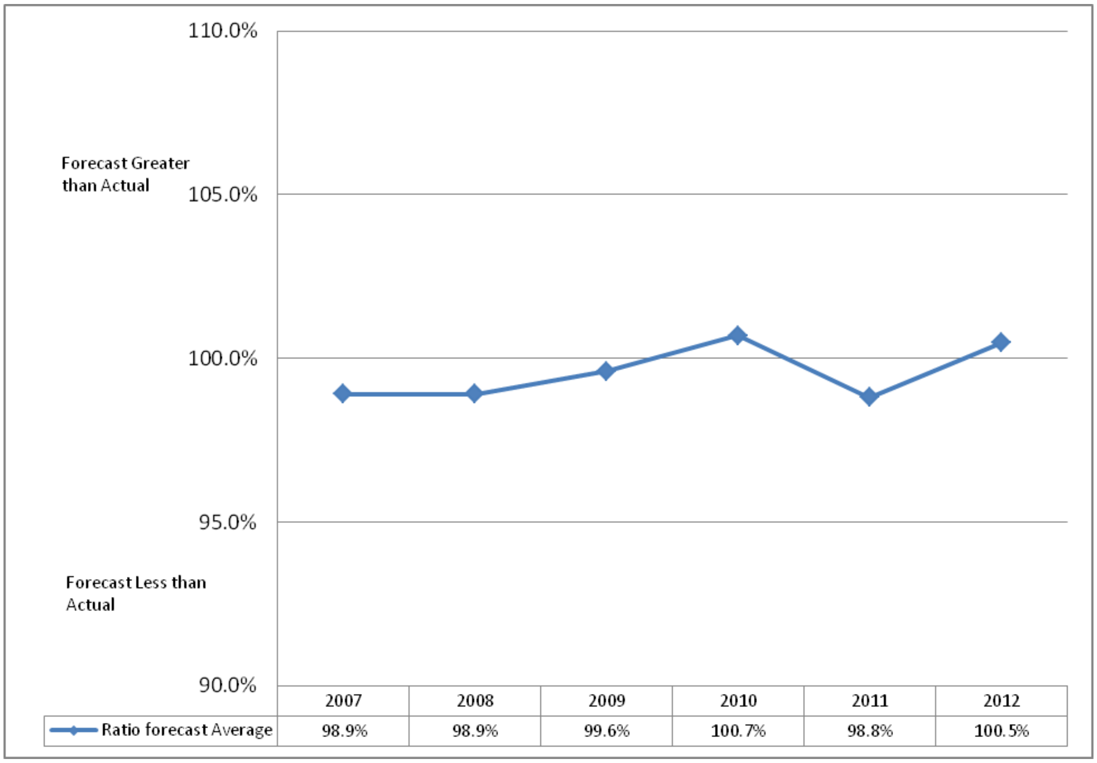
1.3.4 Commercial Customer Additions Forecast Methodology

Commercial customer additions and the existing commercial customer totals are the second key input for the commercial demand forecast. The total customer count (including additions) is multiplied by the average UPC to form the commercial demand forecast. Consistent with prior forecasts, the forecast of Commercial customer additions is based upon an analysis of recent trends in the Commercial rate class.

This method has provided accurate results in the past, as shown in the following figure for Rate Schedules 2, 3 and 23. The figure below compares the forecast (numbers in chart at bottom) to the actual (graphed line) commercial customer totals for 2007 through 2012. The points in the figure are the ratio of actual year end commercial account totals compared to the forecast total for the same period.

From 2007 to 2012, the forecasting error relative to the actual total customer count ranged from 1.2 percent to -0.7 percent with an average of 0.4 percent. Given this variance analysis, trending based on the latest actual customer addition data is believed to provide a reasonable forecast.

Figure C1-8: Comparison of Forecast to Actual Commercial Customers



1.3.5 Industrial Demand Forecast Methodology

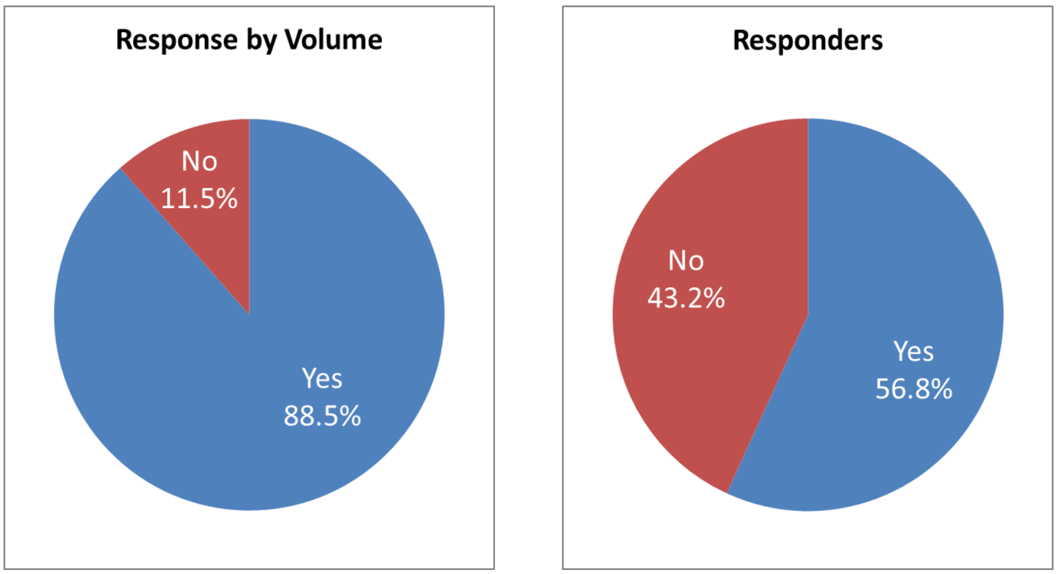
The forecast of Industrial Energy Demand, due to the smaller number of customers in each rate class, is based upon customer specific results from the annual Industrial Demand Survey.

The forecast for Industrial Customer Additions assumes no net change in the number of customers over the forecast period except where specific knowledge has been received by the Company.

The annual Industrial Demand Survey asks each industrial customer for their short-term forecast of monthly consumption and long-term forecast of annual consumption. This data is entered directly into the forecast to produce total demand for each industrial rate schedule. The Company completed the design and development of a new online Industrial Survey this year. Industrial customers received an email invitation to participate in the survey. The email linked the user to their specific data on a secure and encrypted web site. Users were able to see charts of both their historic consumption and their recent consumption compared to the forecast they most recently provided to FEI. The Company believes that this new survey provided our customers with an easy to use system with which they could develop and enter their demand forecast.

Survey response rates increased to 88.5 percent by volume (up from 83 percent in the 2010 Survey) and to 56.8 percent by customer count (up from 53 percent in the 2010 Survey).

Figure C1-9: Response to 2012 Industrial Survey



The Company believes that the improved industrial survey system provides industrial customers with a better opportunity to provide us with an accurate forecast and therefore the resulting forecast of industrial demand is reasonable.

1.3.6 Review of Historical Data

Once the independently developed forecast is complete, it is compared with historic normalized data. Through this comparison, the forecast for gas usage by our customers is verified.

Using the forecast software system we are able to directly compare historic actual data alongside the forecast at many different levels (i.e. use per customer, accounts, energy demand etc). The graphical comparison is available at the rate class level from 2003 through the forecast period. The graphical comparisons allow us to test and confirm the reasonableness of the forecast and are presented in the appropriate sections, below.

1.4 *DEMAND FORECAST AND REVENUES*

1.4.1 Introduction

This section presents the forecast of average UPC, customer additions and total energy demand and margin over the forecast period.

This section is organized as follows:

- Revenue Stabilization Adjustment Mechanism
  - Discusses the method by which delivery margins for residential and commercial customers are stabilized
- Residential and Commercial Use Rates
  - Discusses forecast of average use rates for each rate schedule
- Customer Additions
  - Discusses forecast of net residential and commercial customer additions
- Demand Forecast
  - Discusses total energy demand for all residential, commercial and industrial rate schedules
- Revenue and Margin Forecast
  - Monetization of demand using existing rates

1.4.2 Revenue Stabilization Adjustment Mechanism

The Commission first approved the RSAM in 1994; a deferral account mechanism that stabilizes the margins recovered from residential and commercial customers.[39]

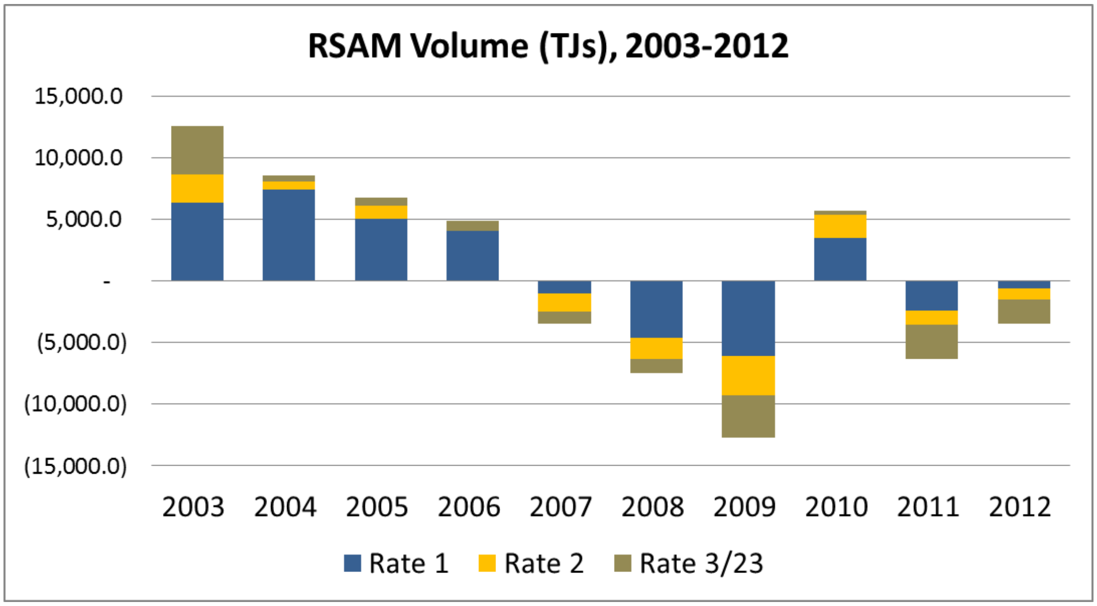
The RSAM stabilizes delivery margin received from residential and commercial customer classes on a UPC basis. If UPC rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, FEI records the delivery charge differences in the RSAM deferral account for refunding or recovering through a rate rider to the RSAM rate classes.

Having an RSAM mechanism does not offer protection against forecasting errors due to variances between recorded and forecast number of customers, nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as industrial customers.

[39] Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X and 23

As shown in the following Figure C1-10, demand under Rate Schedules covered by the RSAM in the Mainland region can vary by +/- 12 PJs in a particular year. Negative volumes indicate below normal temperatures.

Figure C1-10: RSAM Volumes Since 2003



The RSAM captures variances from forecast to actual for factors such as weather that cannot be forecast with any degree of accuracy.

1.4.3 Residential and Commercial Use Rates

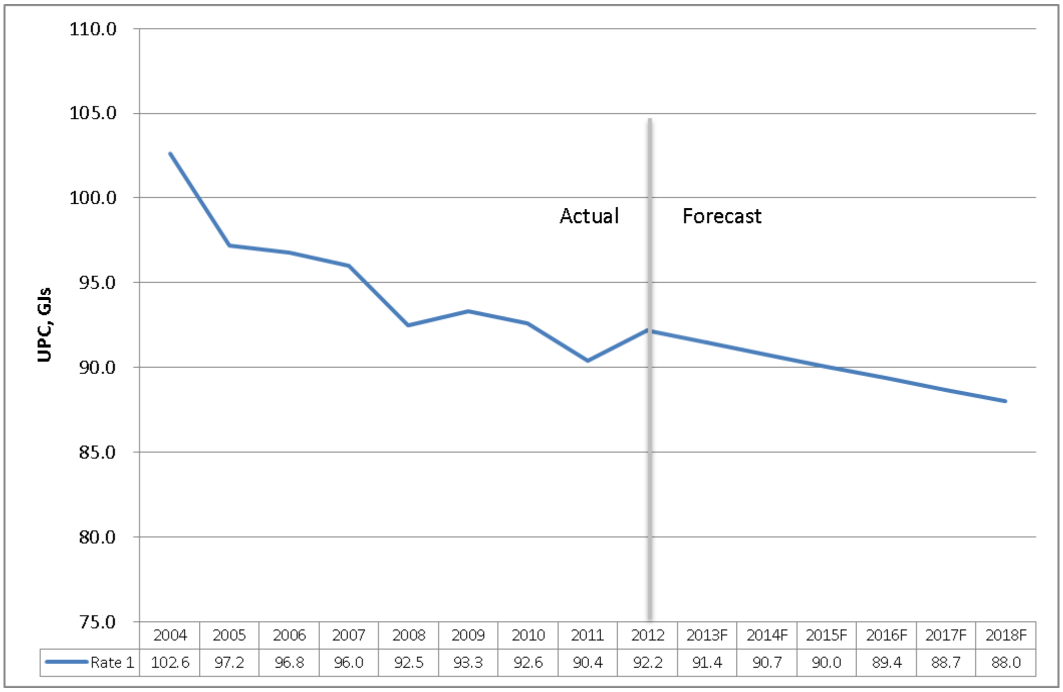
Individual average UPC forecasts are developed for each residential and commercial customer class. The analysis of historic normalized residential use rates indicates a continued downward trend, while normalized commercial average use rates are continuing to increase.

As can be seen from the figures in this section, the forecast of average UPC for residential and commercial rate classes is consistent with the trend of historical values.

The one time increases seen from 2011 to 2012 in rate schedules 1, 2 and 3 are a result of the customer count adjustment in the CIS. The volumes did not change, but the account totals were smaller, so the UPC rates appear higher.

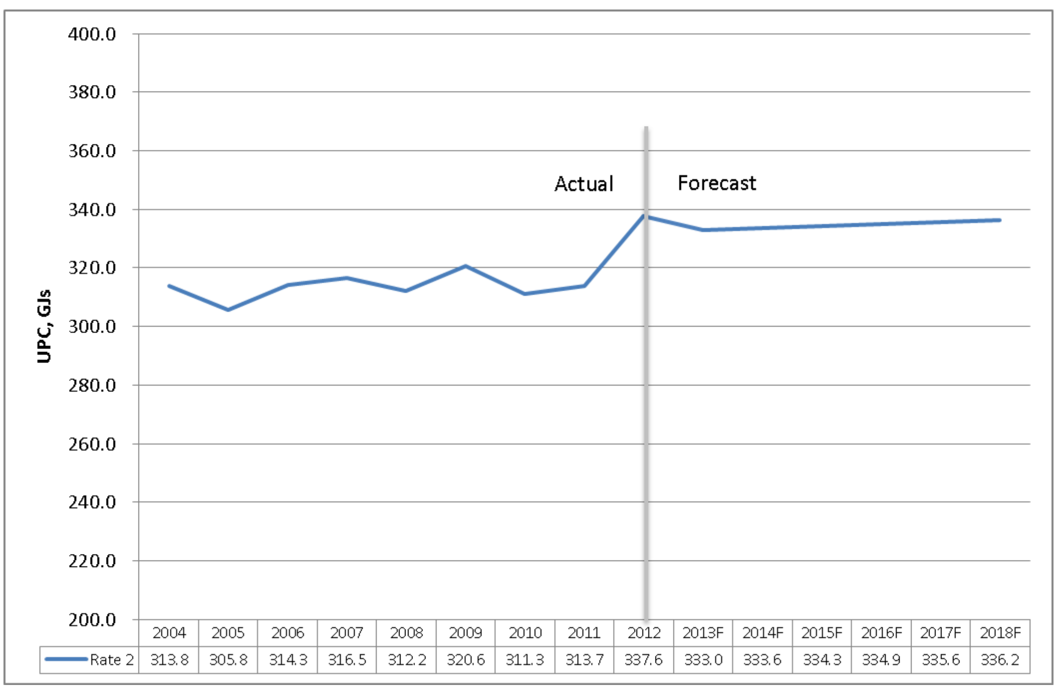
As shown below, the residential UPC is forecast to decline at approximately 0.7 GJ per year (approximately 0.8 percent per year).

Figure C1-11: Rate Schedule 1 UPC Declining Consistent with Prior Years



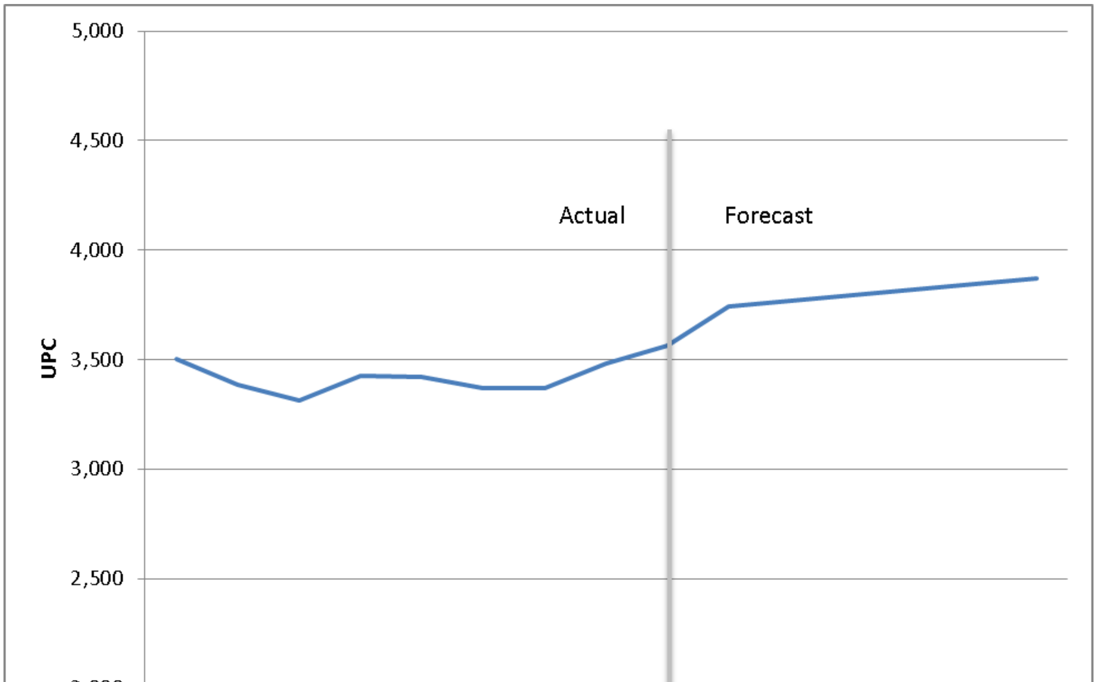
As seen below, the Rate Schedule 2 UPC is forecast to be relatively stable during the forecast period. The annual UPC is forecast to grow at less than 1 GJ per year (approximately 0.2 percent per year).

Figure C1-12: Rate Schedule 2 UPC Consistent with Prior Years



As seen below, the upward trend in Rate Schedule 3 UPC has been consistent and this trend is forecast to continue. The annual increase in the Rate Schedule 3 UPC is forecast to be 25 GJ or approximately 0.7 percent.

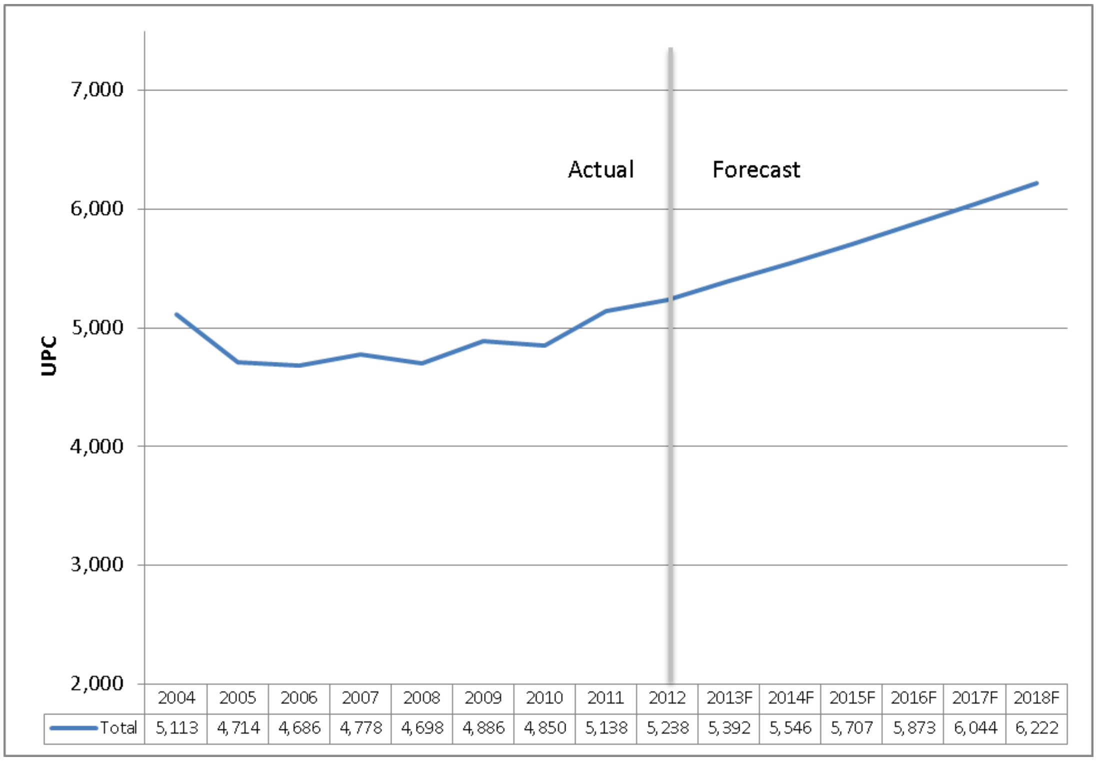
Figure C1-13: Rate Schedule 3 UPC Consistent with Prior Years



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Total	3,501	3,388	3,314	3,426	3,420	3,372	3,370	3,484	3,566	3,746	3,770	3,795	3,821	3,847	3,873

As seen below, the Rate Schedule 23 UPC is forecast to continue the recent upward trend of approximately 2.8 percent per year. Rate Schedule 23 customers are billed each calendar month and as such were not affected by the account adjustment described in Section C1.3.1.

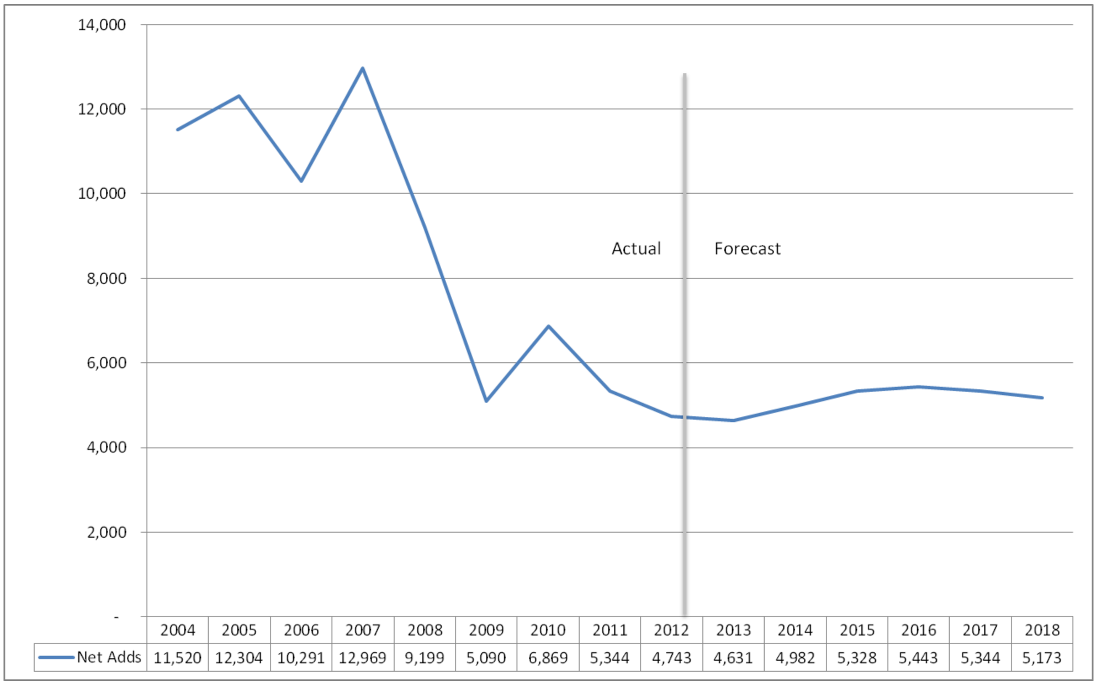
Figure C1-14: Rate Schedule 23 UPC Recent Upward Trend



1.4.4 Customer Additions

The rate of growth seen in our customer base reached a high in 2007 of roughly 12,300 net customer additions then declined in 2008 and 2009. In 2010, account additions rebounded and the Company added just under 6,900 customers. Net additions are expected to stabilize at approximately 5,000 per year for the PBR Period.

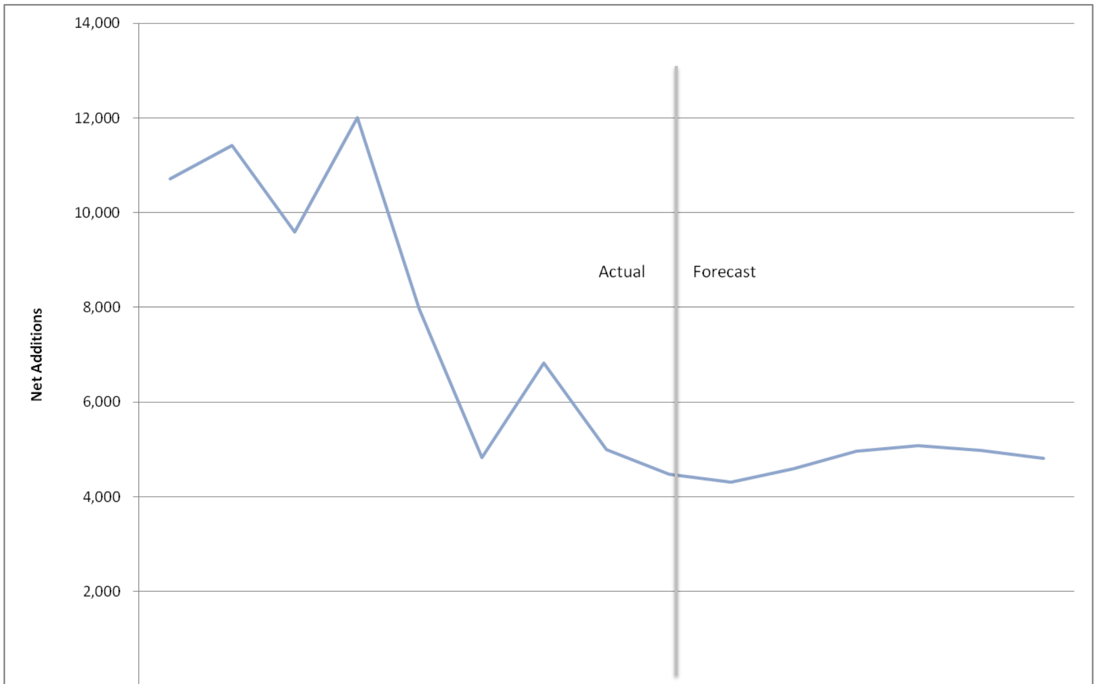
Figure C1-15: Total Customer Growth for all Rate Classes Consistent with Prior Years



No growth in customer additions was assumed for Industrial customers in Rate Schedules 5, 22, 25, and 27 as none were known of at the time of the forecast.

The following Figures (Figures C1-16 and C1-17) provide a breakdown of the residential and commercial net customer additions projected for 2013, and the forecast for the years 2014 through 2018.

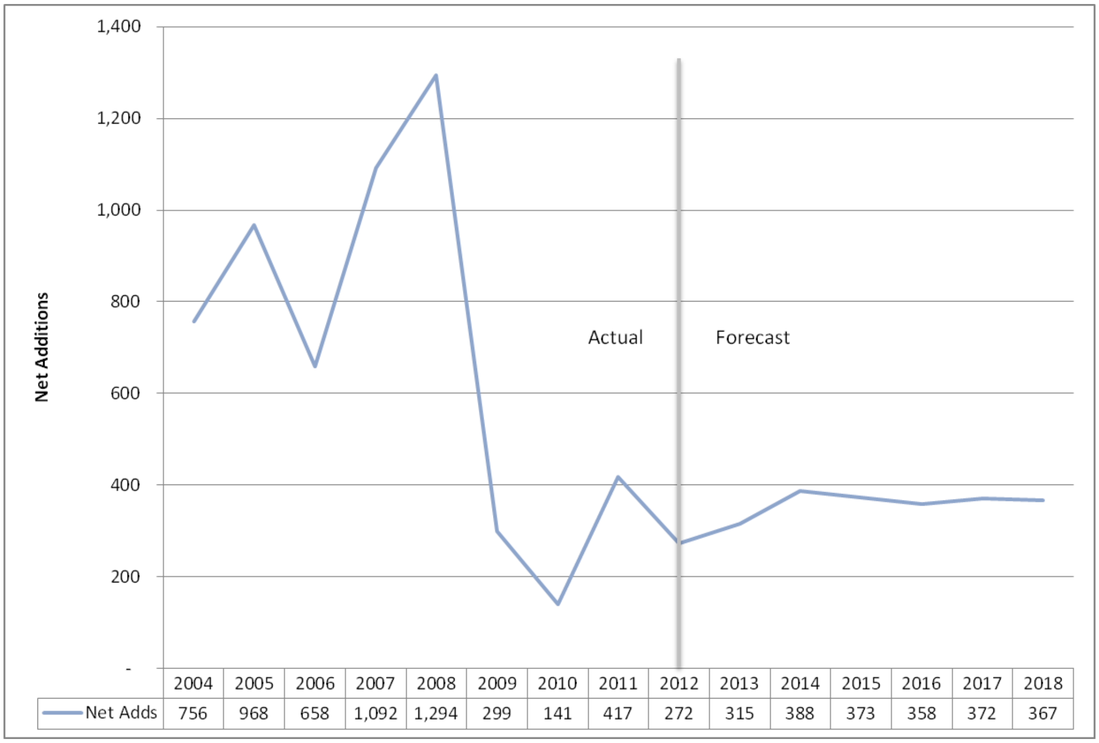
Figure C1-16: Residential Customer Additions



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Net Adds	10,716	11,427	9,595	12,003	7,959	4,822	6,824	4,994	4,475	4,316	4,594	4,955	5,085	4,972	4,806

As shown in the preceding figure, residential net additions rebounded in 2010 from the lows observed in 2009 before declining again in 2011. Additions in 2014 are forecast to be slightly lower than 2011 and then will gradually increase through 2018.

Figure C1-17: Commercial Customers Additions

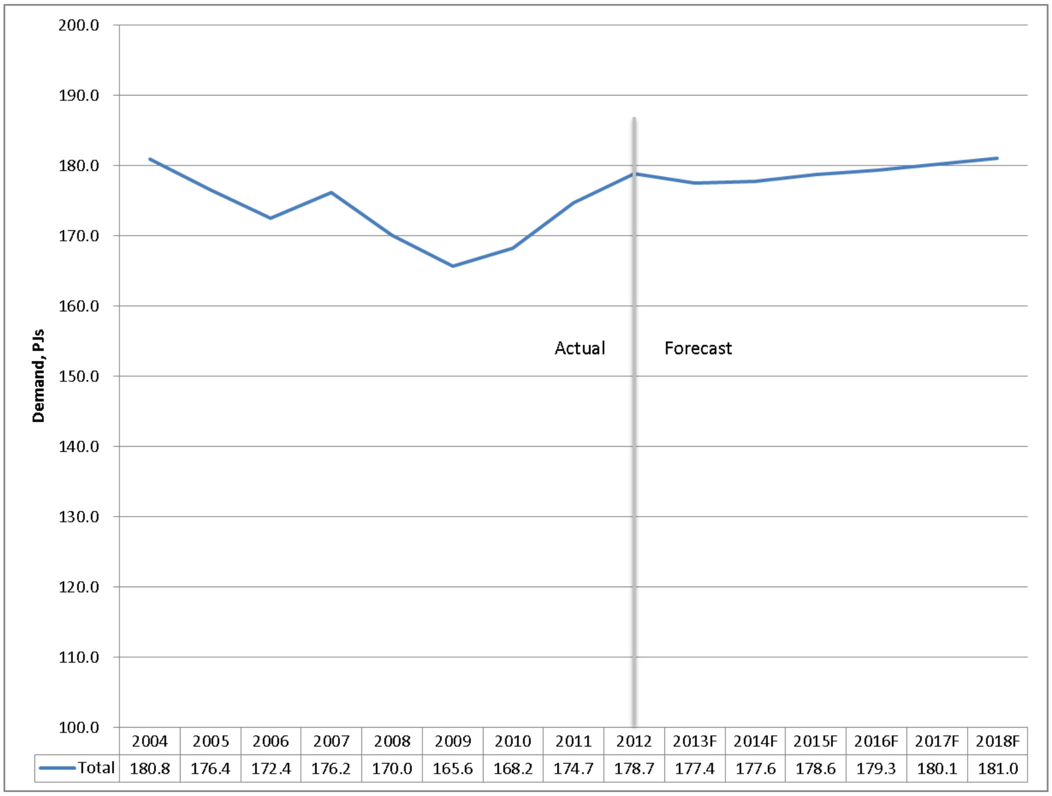


The net commercial customer additions have been declining since the high of 1,294 in 2008. Based on recent data we are forecasting 388 additions in 2014 followed by a slight decline through 2018.

1.4.5 Demand Forecast

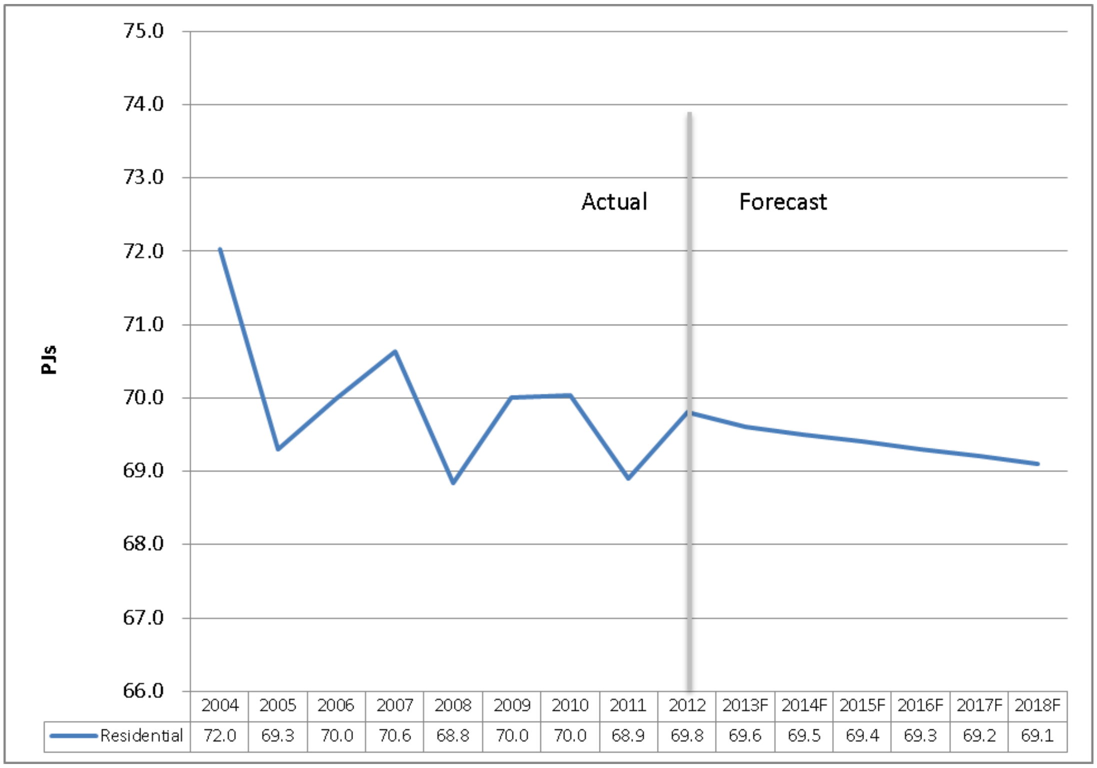
As seen below in Figure C1-18, the total normalized demand is projected to be approximately 177.6 PJs in 2014, in line with recent actuals. For 2014 through 2018 the total normalized demand is forecast to be slightly higher as a result of increases in gas usage in the commercial and industrial rate classes.

Figure C1-18: Total Normalized Energy Demand in PJs



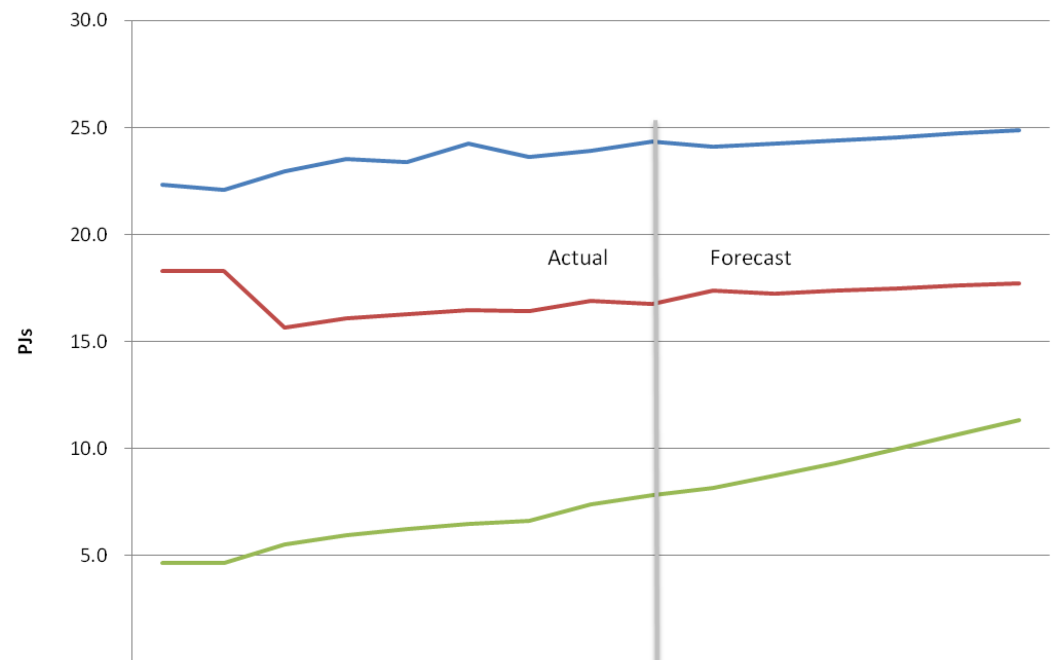
As shown below in Figure C1-19, the growth in residential customers has not offset the decline in average residential UPC, which has resulted in an overall continued decline in residential normalized energy demand.

Figure C1-19: Normalized Residential Demand



As seen in Figure C1-20 below, demand in all three commercial rate classes is forecast to continue the recent upward trends. The upward trends are a result of increasing UPC rates in all three commercial rate classes combined with moderate account growth.

Figure C1-20: Commercial Demand



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
RATE2	22.3	22.1	22.9	23.5	23.4	24.3	23.6	23.9	24.3	24.1	24.2	24.4	24.6	24.7	24.9
RATE3	18.3	18.3	15.6	16.1	16.3	16.5	16.4	16.9	16.7	17.4	17.3	17.4	17.5	17.6	17.7
RATE23	4.6	4.6	5.5	5.9	6.2	6.5	6.6	7.4	7.8	8.2	8.7	9.3	10.0	10.6	11.3

As seen below the demand from the industrial rate classes is forecast to stabilize at approximately 58 PJs/yr, based on responses to the Annual Industrial Survey completed in 2012. Based on the Annual Industrial Survey our customers are not forecasting the recent upward trend that began in 2009 to continue and in 2014 have forecasted an approximate 2 PJ decline from the peak seen in 2012.

Figure C1-21: Industrial Demand

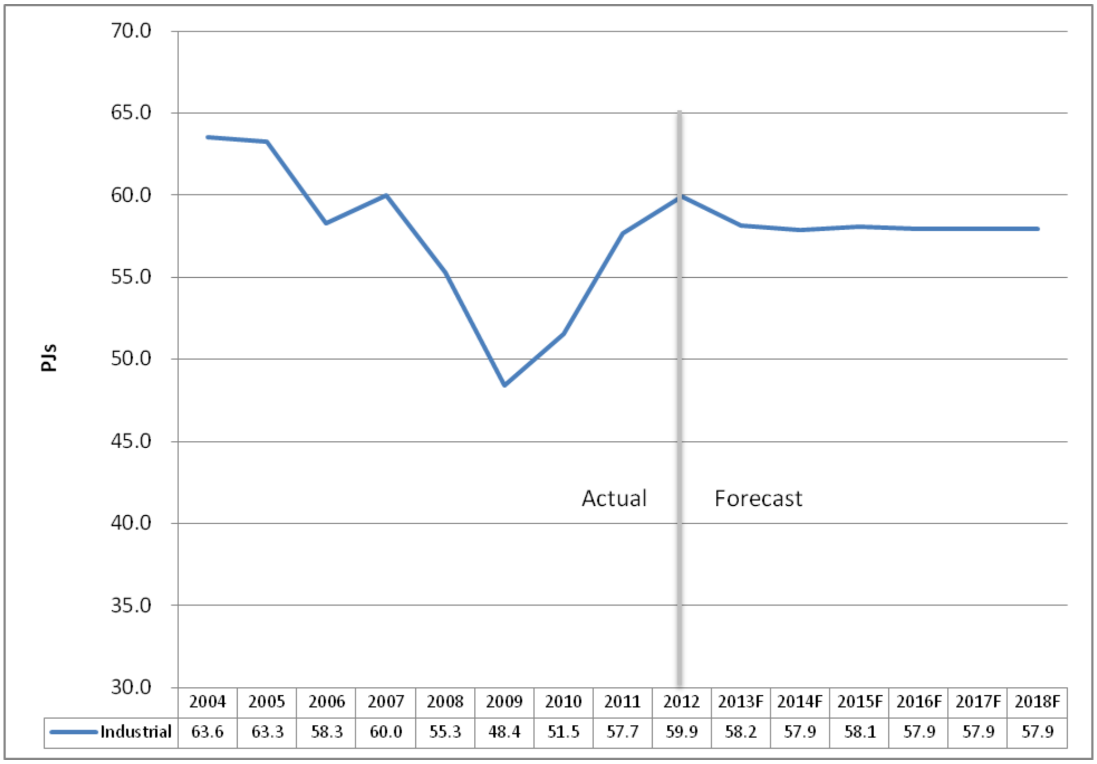


Table C1-4 outlines the total demand by residential, commercial, and industrial sectors for 2013 through 2018 (excluding the demand from Natural Gas for Transportation (NGT) presented in Section C1.4.6 below).

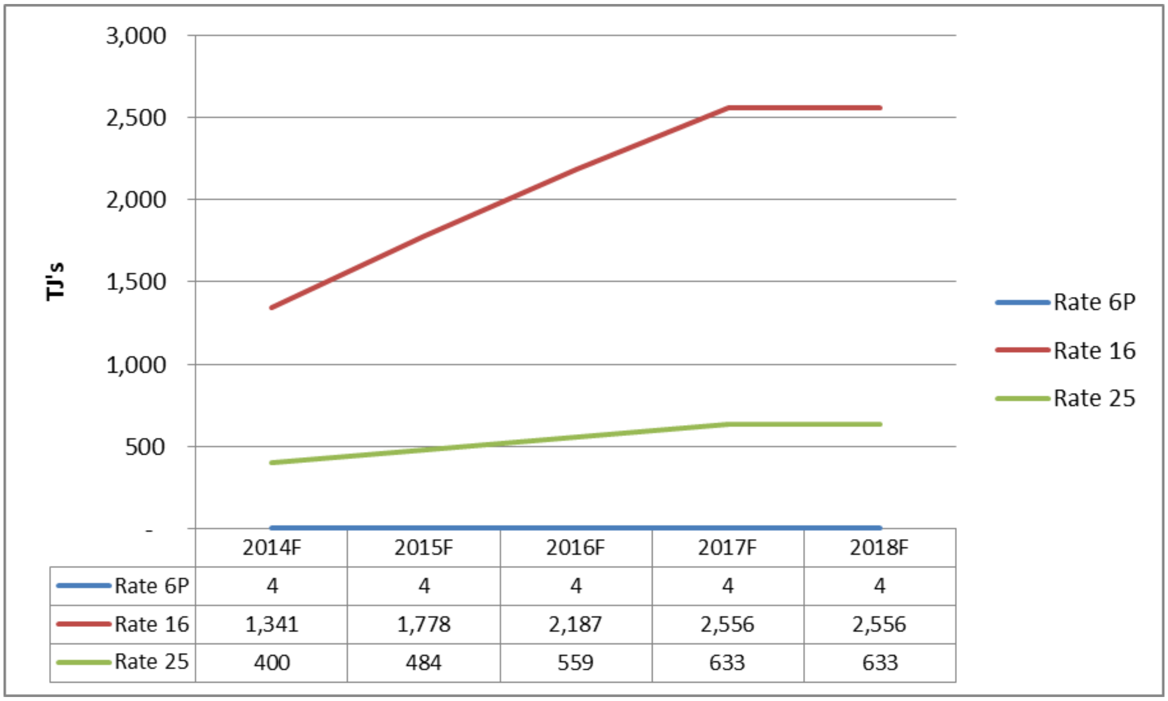
Table C1-4: Forecast Demand in PJs

	2014	2015	2016	2017	2018
FEI					
Residential	69.5	69.4	69.3	69.2	69.1
Commercial	50.2	51.1	52.0	52.9	53.9
Industrial	57.9	58.1	57.9	57.9	57.9
Total	**177.6**	**178.6**	**179.3**	**180.1**	**181.0**

1.4.6 Natural Gas for Transportation

The Greenhouse Gas Reduction Regulation (GGRR) application and subsequent approval on October 29, 2012 with Order G-161-12 has set out prescribed undertakings by which FEI can enable the growth of the NGT market in British Columbia. Demand forecasting for the NGT market has been calculated with reference to these prescribed undertakings. Our normal course of forecasting industrial load is to survey existing customers about their own load and not to forecast new customer additions unless we actually have a new customer signed up. The majority of the NGT volume is from new customers and therefore falls into the new customer realm. As we only have a few existing NGT customers, the NGT forecast is calculated separately. In Appendix H, Section 4 outlines the approach FEI has taken to forecast NGT market demand. Figure C1-22 below shows the forecast demand driven by the NGT market that is incremental to the demand forecast presented in Section C1.4.5 above.

Figure C1-22: NGT Demand, TJ's



	2014F	2015F	2016F	2017F	2018F
Rate 6P	4	4	4	4	4
Rate 16	1,341	1,778	2,187	2,556	2,556
Rate 25	400	484	559	633	633

1.4.7 Revenue and Margin Forecast

A reasonable forecast of revenues and margins has been developed by considering the total energy forecast applied at existing 2013 approved rates.

1.4.7.1 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 applying the total energy forecast to the currently approved rates (as at January 1, 2013) for each customer class. The revenue forecast presented in Table C1-5 does not include amounts for Vancouver Island Wheeling and B.C. Hydro for Burrard Thermal. The 2014 Burrard Thermal revenues are included in the financial schedules in Section E, Schedule 11 of the Application and the Vancouver Island wheeling revenue included in Other Revenue (Section E, Schedule 13) and reflect existing contractual revenue and volume agreements.

Table C1-5 below summarizes the revenues projected for 2013 and forecast for 2014 through 2018, at 2013 rates.

Table C1-5: Forecast Sales Revenue at Existing Rates

Revenue ($ millions)	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential[1]	681.1	676.1	673.7	673.7	673.7	673.5
Commercial[2]	359.0	364.9	369.9	377.7	385.6	390.1
Industrial[3]	78.3	76.2	76.5	76.5	76.6	76.6
Grand Total	**1,118.4**	**1,117.3**	**1,120.1**	**1,127.9**	**1,135.8**	**1,140.1**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 16, 23[40]
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

NGT revenues are embedded within the revenue numbers shown in Table C1-5. The embedded amounts are shown in Table C1-6 below.

Table C1-6: Forecast Sales Revenue for NGT at Existing Rates[41]

Revenue ($ millions)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Rate 6P	0.0	0.0	0.0	0.0	0.0
Rate 16	10.8	14.8	18.8	22.7	23.3
Rate 25	0.3	0.4	0.4	0.5	0.5
Total	**11.1**	**15.2**	**19.3**	**23.2**	**23.8**

1.4.7.2 Cost of Gas

The cost of gas includes the cost of natural gas, propane, and biomethane, with propane and biomethane making up a very small component of the FEI gas supply portfolio. The table below sets out the forecast cost of gas at existing rates, by rate schedule group.

[40] Implications to Rate Schedule 16 Revenues pursuant to Order G-88-13 received on June 4, 2013 will be addressed through an evidentiary update to this application once the decision has been fully evaluated
[41] Rate Schedule 6P shows as zero due to presenting the dollars values as millions.

Table C1-7: Forecast Cost of Gas at Existing Rates

Cost of Gas ($ millions)	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential[1]	310.5	305.4	302.8	302.4	302.0	301.5
Commercial[2]	184.5	184.0	184.6	188.0	191.6	193.3
Industrial[3]	10.3	10.1	10.1	10.1	10.1	10.1
Grand Total	**505.4**	**499.5**	**497.5**	**500.5**	**503.6**	**504.9**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 16, 23[42]
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

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. During the PBR Period FEI will continue to report gas costs on a quarterly basis, as required under the Commission Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance (established pursuant to Commission Letters L-05-01 and L-40-11). 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 cost of gas comprises two main components, the commodity and midstream, as discussed briefly below. Further, the total cost of gas for the purposes of this Application has been determined by multiplying forecast sales volumes by the existing (as of January 1, 2013) unit gas cost recovery charges for each rate schedule.

FEI's total cost of gas consists of the commodity and the midstream components. The commodity component includes the costs for purchasing the baseload gas commodity and an allocated share of the Core Market Administration Expense (CMAE). The midstream component includes the costs for the contracted third party pipeline and storage resources, spot and peaking gas purchases, and contains costs for unaccounted for gas (UAF) and the midstream share of the CMAE. UAF and the CMAE are described further below.

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. The cost of UAF related to the Sales

[42] Implications to Rate Schedule 16 Cost of Gas pursuant to Order G-88-13 received on June 4, 2013 will be addressed through an evidentiary update to this application once the decision has been fully evaluated

rate classes is included in the cost of gas and recovered from core customers[43] 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.

The cost of gas includes CMAE costs required to manage the FEI's natural gas and propane supply functions. The gas supply function encompasses most elements of the merchant role, ensuring that there are reliable, secure and cost effective supplies of gas for core customers. These management activities are carried out by Gas Supply, which is an area within the Energy Supply and Resource Planning department. The CMAE forecasts that are included in the cost of gas for 2014 through 2018 will be submitted for Commission approval as part of the Company's routine gas cost reporting and rate setting process.

1.4.7.3 Margin

Margins are calculated by subtracting the cost of gas from the total revenues.

Table C1-8 below summarizes the margin projected for 2013 and forecast for 2014 through 2018, by customer segment, at 2013 approved rates.

Table C1-8: Forecast Gross Margin at Existing Rates

Margin ($ millions)	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential[1]	370.6	370.7	370.9	371.3	371.7	372.0
Commercial[2]	174.5	180.9	185.3	189.7	194.0	196.8
Industrial[3]	68.0	66.2	66.4	66.4	66.5	66.5
Grand Total	**613.1**	**617.8**	**622.6**	**627.5**	**632.2**	**635.3**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 16, 23[44]
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

NGT margins are embedded within the margin numbers shown in Table C1-8. The amounts are shown in Table C1-9 below.

[43] Core customers are those for whom FEI is obligated to ensure the purchase, transportation, and uninterrupted delivery of natural gas to their premises.
[44] Implications to Rate Schedule 16 Gross Margin pursuant to Order G-88-13 received on June 4, 2013 will be addressed through an evidentiary update to this application once the decision has been fully evaluated

Table C1-9: Forecast Gross Margin for NGT at Existing Rates[45]

Margin ($ millions)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Rate 6P	0.0	0.0	0.0	0.0	0.0
Rate 16	5.5	7.3	9.0	10.5	10.5
Rate 25	0.3	0.4	0.4	0.5	0.5
Total	**5.8**	**7.7**	**9.4**	**11.0**	**11.0**

Revenues are comprised of both fixed and variable charges, and the portion each contributes to margin varies for each customer segment. The revenues for the Residential and Commercial customer segments have a smaller portion of fixed to variable charges (approximately 20 percent fixed, 80 percent variable) than do the firm sales and Industrial customer segments, where approximately 55 percent of revenues are fixed compared to 45 percent variable. This means that the margin collected for Residential and Commercial customers is more influenced by annual fluctuations in consumption patterns than it is for firm sales and Industrial customers. However, use rate fluctuations for Rate Schedules 1, 2, 3 and 23 are captured through the RSAM mechanism referred to in Section C1.4.2. Margins collected from firm sales and Industrial customers, due to the nature of their contracts, are partially protected from yearly fluctuations in usage patterns through the use of contract demand (CD), minimum volume and firm daily take quantities (DTQ) whereby these customers may pay a minimum amount regardless of usage.

1.5 *SUMMARY*

Through considering the factors influencing customer additions, average UPC and also Industrial volumes the Company has developed a forecast of demand for natural gas. Residential customers continue to look for ways in which to improve efficiencies and average UPC is forecast to continue to decline over the forecast period. Commercial customer additions are forecast to increase, as are the use rates for all three commercial rate classes. As a result, the commercial demand forecast continues to trend upwards. The 2012 Annual Industrial Survey indicated that overall Industrial volumes will decrease slightly from the peak seen in 2012. It is through considering these factors, applying methods consistent with prior years, and by using the latest information available that the Company believes it has developed a reasonable demand forecast for the 2014 through 2018 forecast period. As part of the annual rate setting process, FEI will be reforecasting its demand each year; therefore the forecasts for 2015 through 2018 will be updated in the future.

1.6 *IMPACT OF VARIANCES IN CUSTOMER ADDITIONS*

FEI provides the following summary in response to Commission Directive #1 in the 2012-2013 RRA Decision (page 27 and Appendix A, page 1):

[45] Rate Schedule 6P shows as zero due to presenting the dollars values as millions.

> *"The Commission Panel agrees with the BCOAPO that it would be of value for the FEU to file a financial analysis of the impact of variances in the forecast of customer additions on all rate classes when they file their next RRA and the FEU are directed to do so."*

The approach taken by FEI to address this directive was to assess the customer classes that are primarily associated with the customer addition variances, to approximate the variability in the use per customer from a new customer and then to approximate the resulting variability in incremental capital, cost of service and the resulting impact on earned return.

Although the number of permutations from variances in customer additions and how they could impact the Company financially are infinite, for purposes of this analysis, FEI calculated 48 financial impact scenarios using combinations of the following:

- four customer classes including Residential (Rate Schedule 1), Small Commercial (Rate Schedule 2), and Large Commercial (Rate Schedule 3 – Sales and Rate Schedule 23 – T-Service);
- low, average and high Use per Customer (UPC) scenarios; and
- low, average and high and capital cost scenarios with an additional no main extension cost scenario.

Based on the analysis, FEI concludes the following:

1. For residential and commercial customers, any variation in the customer demand from what has been forecast in rates has no impact on the gross margin earned from a new customer because of the RSAM mechanism.
2. Due to the main extension (MX) test and resulting CIAC and also the Service Line Cost Allowance (SLCA) that is applicable to residential and small commercial customers, capital cost exposure to the rate base is limited when adding customers.
3. There is a relatively small variance on the earned return from the effect of the incremental capital cost of adding or not adding a customer, all else being equal. In all scenarios there is a positive impact on the earned return when adding a customer that was not forecast and conversely a negative impact to earned return when not adding a customer that was forecast.
4. Any increase or decrease in earned return is temporary until the next time delivery rates are reset.
5. There is no consistent historical experience of over or under forecasting customer additions.
6. The historical 10 year average would suggest it is more likely for the utility to experience a slight decrease in earned return (approximately $227 thousand) compared to the forecast due to actual customer additions being, in general, less than forecast.

7. In all cases, when adding customers, there is a positive effect on the incremental delivery margin and earned return and these additions will help to offset future rate increases when delivery rates are next reset.

The full analysis to support these summary statements is included in Appendix E.

2. OTHER REVENUE

2.1 INTRODUCTION AND OVERVIEW

As demonstrated in the table below, FEI is forecasting other revenues at a similar level as that approved for 2013, after adjusting for the CNG and LNG Service Recoveries, as described in Section C2.2.3..

Table C2-1: 2013 and 2014 Other Revenue Components

Other Operating Revenue, ($ thousands)			
	Approved 2013	Projected 2013	Forecast 2014
Late Payment Charge	$ 2,333	$ 2,134	$ 2,114
Connection Charge	2,685	2,622	2,636
NSF Returned Cheque Charges	79	79	79
Other Recoveries	126	284	284
FEVI Wheeling Charge	3,464	3,464	3,365
SCP Third Party Revenue	14,827	14,773	14,773
NGT Overhead and Marketing Recovery	-	-	490
Burnaby & Surrey Operations Pump Charges	-	(55)	(55)
Biomethane Other Revenue	(29)	(97)	(70)
CNG & LNG Service Revenues	1,304	-	-
Total Other Operating Revenue	**$ 24,789**	**$ 23,204**	**$ 23,616**

The PBR Period forecast was prepared using a consistent methodology to that approved in the 2012-2013 RRA. 2015 through 2018 forecasts for each item will be updated each year during the Annual Review. The currently forecasted amounts for those years result in an annual average increase of approximately 1.4 percent per year in revenue due mainly to the volume-driven annual increases in the NGT Overhead and Marketing recovery.

In the following sections, FEI summarizes the new and discontinued sources of other revenue for 2014, and then addresses the largest component of other revenue, the SCP third party revenue.

2.2 NEW AND DISCONTINUED SOURCES OF OTHER REVENUE FOR 2014

2.2.1 NGT Overhead and Marketing Recovery (New)

Pursuant to Order G-78-13 and with reference to Appendix H, Section 5.2, FEI has forecast a recovery of overhead and marketing (OH&M) costs from the NGT Classes of Service. The charge represents a recovery from the NGT Classes of Service for overhead and marketing costs incurred by the Natural Gas for Distribution Class of Service. The OH&M rate of $0.52 per GJ is multiplied by forecast CNG and LNG sales volumes and credited to the Natural Gas for Distribution Class of Service. FEI notes that the total OH&M recovery in 2014 is forecast at $490 thousand at the currently approved rate. If the rate remains at $0.52 then the OH&M recovery is projected to grow to $1.3 million by 2018 for a total of $5 million over the PBR Period. As discussed in Appendix H, these recoveries exceed the amount of actual O&M costs embedded in the Natural Gas for Distribution Class of Service, and at the current rate represents a cross subsidization from the NGT class of service to the Natural Gas for Distribution Class of Service. FEI will revisit the appropriateness of the $0.52 rate in future filings.

2.2.2 Surrey & Burnaby Operations CNG Pump Charges (new)

The FEI fleet consumes CNG from CNG pumps located in the Surrey and Burnaby Operations yards. Pursuant to BCUC decisions[46] regarding accounting for NGT assets in separate classes of service from the Natural Gas for Distribution Class of Service, the Surrey and Burnaby CNG pumps have been accounted for in the Non-GGRR CNG Class of Service[47]. Consequently, the cost of service of these pumps is excluded from the rate impact to Natural Gas for Distribution Class of Service customers. However, since the FEI fleet uses these pumps to fuel its fleet vehicles, Natural Gas for Distribution Class of Service customers must pay for this service.

The Burnaby Operations CNG pump is used exclusively by the FEI fleet. Therefore the total cost of service for this pump is reflected in this charge (approximately $28 thousand per year). Surrey Operations CNG pump is used partially by FEI's fleet and partially by the public. Therefore, the cost to Natural Gas for Distribution Class of Service customers reflected in this charge is the forecast FEI Fleet volume of CNG from this pump multiplied by the Compression and Dispensing charge from Rate Schedule 6P, approved by Order G-165-11A (approximately $27 thousand per year). The total annual cost is therefore forecast at $55 thousand per year.

2.2.3 CNG and LNG Service Revenues (Discontinued)

In the 2012-2013 RRA, FEI had forecast both fuelling station revenue and incremental delivery margin revenue as part of Other Revenue. Starting in 2013, FEI will be accounting for all NGT Fuelling stations in separate classes of service from Natural Gas for Distribution Class of Service. Therefore, all fuelling station revenue is forecast in the NGT Class of Service and not to the account of Natural Gas for Distribution Class of Service customers. Any delivery margin revenues driven by NGT volumes are included in the revenue forecasts in Section C1.4.6. Please refer to Appendix H for a discussion on the NGT classes of service.

[46] Commission Orders C-6-12, G-161-12, G-201-12, G-56-13.
[47] See Appendix H for a detailed overview of FEI's accounting for NGT assets and Class of Service discussion.

2.3 SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE

The SCP Third Party Revenue for 2013 and 2014 includes the items shown in the table below.

Table C2-2: 2013 and 2014 SCP Revenue Components

Southern Crossing Pipeline Revenue, ($ thousands)	Approved 2013	Projected 2013	Forecast 2014
Northwest Natural Gas Co.	$ 5,573	$ 5,470	$ 5,470
MCRA	3,600	3,600	3,600
Motor Fuel Tax	(50)	-	-
Net Mitigation (T-South Enhanced Service)	5,703	5,703	5,703
Total Other Operating Revenue	**$ 14,827**	**$ 14,773**	**$ 14,773**

The SCP Revenues related to contracted capacity are discussed separately below; taxes (Motor Fuel Tax and Carbon Tax) on compressor fuel are recovered from these SCP shippers. 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 three year period. Please refer to Appendix F4 for a discussion of this deferral account.

2.3.1 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 2012-2013 RRA, the NWN revenues are recorded net of the costs for the Spectra Energy Kingsvale South Transportation and the PG&E termination fees as shown in Table C2-3 below.

Table C2-3: Calculation of 2014 Northwest Natural Gas Co. Revenue

	($thousands)
NWN Revenue	$ 8,995
Spectra Transportation Tolls	$ (3,380)
PG&E Termination Fee	$ (145)
Net NWN Revenue	**$ 5,470**

2.3.2 MCRA

The revenue of $3.6 million per year is related to the inclusion of SCP capacity in the MCRA portfolio. Through Order G-44-12, 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 2012 and 2013. The Company continues to believe that this treatment of costs and revenues is fair and appropriate given that SCP capacity is an essential part of its midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers.

In this Application, the Company seeks approval for the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2014-2018 PBR Period. Consistent with the 2012-2013 RRA, the MCRA will continue to pay for the cost of their portion of the Spectra Energy Kingsvale South capacity.

2.3.3 Net Mitigation Revenue (T-South Enhanced Service)

As part of the SCP Revenue, the Company has included revenue associated with the T-South Enhanced Service which is forecast to be $5.7 million per year. The T-South Enhanced Service is an initiative between Spectra Energy and the Company that adds value to Spectra Energy's T-South service by providing shippers the option to access the Kingsgate market through the Company's Interior Transmission System (ITS) and SCP. As a result of this initiative with Spectra Energy, the Company's customers benefit from increased liquidity in the BC marketplace, decreased T-South tolls and incremental SCP mitigation revenue.

The initial term of the T-South Enhanced Service was May 1, 2010 to April 30, 2012. As a result of the success of this service, Spectra Energy and the Company executed an extension of the Service to October 31, 2014 which was approved by the Commission in Order G-69-11 dated April 14, 2011. FEI anticipates the service will be extended beyond the current expiry date.

2.4 *SUMMARY OF OTHER REVENUE*

FEI has forecast the other revenue components for 2014 reflecting all applicable contracts and fixed revenues, based on our best knowledge of the factors that drive the variable components. The forecasts for the years 2015 through 2018 for each component of Other Revenue will be updated as part of the Annual Review process.

3. OPERATIONS AND MAINTENANCE (O&M) EXPENSE

3.1 *INTRODUCTION AND OVERVIEW*

This section provides both historical and forecast O&M for FEI for the period 2010 through 2018 for each department of the Company. A 2013 O&M Projection is provided in comparison to 2013 Approved O&M as well as historical actual O&M in 2010, 2011 and 2012. FEI has also adjusted the 2013 O&M Projection to the 2013 O&M Base for PBR purposes, which is forward looking. The 2013 O&M Base can then be used for a consistent comparison against the 2014-2018 Forecast O&M and the formula O&M approach discussed in Section B6.2.4.

The 2014 through 2018 O&M forecasts included in this section are included for reference purposes. They represent a high level forecast of future trends and upcoming challenges for FEI. The Company's proposed PBR Plan does not rely on the forecast O&M costs included in this section. Instead, it relies on a formula-based approach, as discussed in Section B of this Application. As noted in Section B, the formula-based approach generates O&M costs for the 2014-2018 years that are below the Company's forecast O&M costs included in this section. FEI will therefore be required to find productivity improvements during the upcoming PBR Period in order to offset the costs it is forecasting in this section.

3.1.1 Department Overview

O&M expenditures are required to operate and maintain the system and provide administrative support to the business. This section provides O&M on a department basis. These departments are listed below. A description of the responsibilities of each department is included in the referenced sections.

- Section C3.4: Operations (Distribution, Transmission and Plant Operations)
- Section C3.5: Customer Service
- Section C3.6: Energy Solutions and External Relations
- Section C3.7: Energy Supply and Resource Development
- Section C3.8: Information Technology
- Section C3.9: Engineering Services and Project Management
- Section C3.10: Operations Support
- Section C3.11: Facilities
- Section C3.12: Environment, Health, and Safety
- Section C3.13: Finance and Regulatory Services

- Section C3.14: Human Resources
- Section C3.15: Governance
- Section C3.16: Corporate

3.1.2 BCUC Uniform System of Accounts

In addition to providing O&M by the departments listed above, 2008 through 2018 O&M is also provided in accordance with the BCUC-reviewed Code of Accounts in both a Resource View and an Activity View in Appendix F6. The totals of the Activity View provided in Appendix F6 reconcile to the departmental view provided in this section.

As part of this Application, the O&M Code of Accounts has been revised in accordance with input from the BCUC Staff. Directive 63 of Order G-44-12 issued on April 12, 2012 directed FEU to investigate the cost of fully converting to the BCUC Uniform System of Accounts (USoA) and to file a proposed plan for conversion. On October 12, 2012 FEU submitted a compliance filing that consisted of a report on the USoA to address the underlying concerns of the Directive, and a proposal for an alternate approach, which included updating the O&M Code of Accounts. On December 3, 2012 the Commission replied that it had reviewed FEU's proposed alternate approach and accepted it for the next RRA only.

In accordance with the approved alternate approach, the information included in Appendix F6 of this Application is presented using the updated view of the O&M Code of Accounts.

3.2 *HISTORICAL O&M BY DEPARTMENT*

Summary O&M by department for the years 2010 through 2013 is shown below in Table C3-1.

Table C3-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Operations	54,444	55,756	59,806	58,599	63,509	63,189
Customer Service [1]	53,278	56,575	40,737	49,115	41,825	52,452
Energy Solutions & External Relations	14,636	15,456	18,075	17,509	19,215	18,181
Energy Supply & Resource Dev	2,075	3,409	3,488	3,664	4,000	3,738
Information Technology	17,320	18,654	23,442	24,553	24,217	25,379
Engineering Services & PM	13,566	14,329	13,599	16,705	15,456	16,956
Operations Support	10,916	10,580	11,038	12,132	11,867	12,990
Facilities	7,329	6,835	9,563	9,509	9,249	9,259
Environment Health & Safety	2,427	2,445	2,481	2,749	2,681	2,999
Finance & Regulatory Services	12,177	12,064	12,149	13,129	13,279	14,184
Human Resources	8,823	8,170	8,610	8,983	8,458	8,511
Governance	7,368	7,895	7,366	7,602	7,935	7,935
Corporate	2,158	1,439	1,915	2,743	(358)	230
	206,518	213,606	212,269	226,993	221,333	236,003

1 Excludes deferred Customer Service O&M for 2012 Actual and 2013 Projection

From 2010 to 2013 Projection, the period covered by this table, O&M is shown to have increased at an annual rate of 2.4 percent. For the most part, increases are gradual and ongoing, except for 2012 where several initiatives were postponed pending an RRA decision that arrived in April of that year. Actual 2012 O&M was approximately $14.7 million lower than the approved amount, of which $7.4 million was captured in the Customer Service Variance deferral account and will be returned to customers. The projection for 2013 incorporates sustainable savings realized in 2012 (as discussed below) and is $14.7 million lower than the approved amount. Of this $14.7 million, $10.3 million is being captured in the Customer Service Variance deferral account and will be returned to customers. This $14.7 million savings has been flowed through to the 2013 O&M Base that sets customer rates for the PBR Period, and results in a sustainable benefit to customers.

As discussed in Section B6.2.4, the total sustainable savings reflected in the 2013 projection and 2013 O&M Base was based on an analysis of 2012 Actual experience. FEI segregated the variance between 2012 Actual and 2012 Approved into sustainable and temporary savings, and deducted the sustainable savings from the 2013 Approved amount. In total, FEI is projecting $9.4 million in sustainable labour savings and $5.3 million in sustainable non-labour savings. The labour savings arise primarily in the Operations, Information Technology, Engineering Services & Project Management, Operations Support, Human Resources and Finance/Regulatory departments. Each department's section below includes a discussion of the nature of these savings. The labour savings are primarily driven by integration activities with FBC, savings in IBEW training through the use of new delivery models, refinement of the requirements for supporting capital activities, streamlining processes and the use of technology, and a shift to the use of contractors to allow more flexibility in staffing levels. Savings in non-labour resulted from the savings in meter reading and billing operations captured in the

Customer Service Variance deferral account, offset by increases to support customer and code-driven requirements, and the increased use of contractors.

3.3 *2014-2018 FORECAST O&M OVERVIEW*

3.3.1 2013 Base O&M

In Section B6.2.4 of the Application, FEI has reconciled the 2013 Approved to the 2013 Base used for setting rates under FEI's PBR Plan. In that section, FEI describes the nature of the adjustments and why they should be included in the 2013 Base O&M that is used for rate setting purposes. This section reconciles the 2013 Approved to the 2013 Base on a departmental basis, to provide a starting point for departmental discussion of future trends and pressures for the PBR Period.

The reconciliation of the 2013 Base O&M to the 2013 Approved O&M by department is shown below in Table C3-2. This table highlights those departments that have achieved sustainable productivity savings for 2013 that will be realized by customers over the PBR Period as discussed above.

Table C3-2: 2013 Departmental O&M Reconciliation ($ thousand)

		Productivity		2013 Deferrals			Accounting Changes		
	2013 Approved	(Sustainable Savings)	2013 Projection	PST (full year)	BCUC Fees & Insurance	Pension/OPEB (O&M portion)	Pension/OPEB (Retiree portion)	Software Fees	2013 Base
Operations	63,189	320	63,509	137		3,667	1,704		69,016
Customer Service [1]	52,452	(10,627)	41,825	18		1,744	810		44,398
Energy Solutions & External Relations	18,181	1,034	19,215	23		1,012	470		20,721
Energy Supply & Resource Dev	3,738	262	4,000	7		295	137		4,440
Information Technology	25,379	(1,162)	24,217	340		691	321	(1,800)	23,768
Engineering Services & PM	16,956	(1,500)	15,456	58		1,027	477		17,018
Operations Support	12,990	(1,123)	11,867	69		802	373		13,111
Facilities	9,259	(10)	9,249	40		146	68		9,504
Environment Health & Safety	2,999	(319)	2,681	12		123	57		2,872
Finance & Regulatory Services	14,184	(906)	13,279	3	923	597	277		15,079
Human Resources	8,511	(53)	8,458	22		487	226		9,192
Governance	7,935	-	7,935	-	93	-	-		8,028
Corporate	230	(587)	(358)	34		13	(5,851)		(6,161)
	236,003	(14,670)	221,333	762	1,016	10,605	(930)	(1,800)	230,985

1 2013 Projection excludes Customer Service deferred O&M

3.3.2 Overview of Cost Drivers

O&M expenditures over the PBR Period will be influenced by a number of drivers with cost pressures coming from different sources. Incremental O&M changes are driven by five broad based business drivers: (i) labour inflation and benefits, (ii) customers, (iii) productivity, (iv) demographics, and (v) system reliability and safety. Each driver is described below.

3.3.3 Labour Inflation and Benefits

For the purposes of compensation and benefits, our workforce is separated into three primary groups:

- Executives;
- M&E employees; and
- Unionized employees represented by the IBEW and COPE unions.

Although the details of the compensation and benefits programs vary between these three groups, the Company applies a consistent philosophy and approach to compensation and benefits for all employees. This approach includes a total compensation package that provides employees with competitive base salaries and wages, incentive compensation, benefits, and paid time-off.

3.3.3.1 Executive Employees

The executive compensation package is designed to retain and attract qualified and experienced executives while balancing the needs of the business and the customer. As a general policy, the Company compensates executives at a level generally equivalent to the median of practice among a broad reference group of Canadian commercial industrial companies. The practice includes compensation and incentives to reward performance.

The Company's executive compensation program involves four main elements:

- base pay;
- short term incentive pay;
- long term incentive pay; and
- benefits.

All of these elements support the needs of the business and its customers, and contribute to finding a balance on delivering successfully on both short and longer term objectives. The objectives of the base compensation package are to recognize market pay, and acknowledge competencies and skills of individuals. The objectives of the short-term incentive plan are to reward achievement of short-term financial and operating performance objectives such as key customer service metrics and focus on achievements critical to the ongoing success of the Company. Long-term incentives are generally accepted as a standard element in executive compensation. Participation in a long term incentive program serves the interests of the customers by incenting delivery on long-term strategies. Focusing on short-term business strategies could have adverse effects on system reliability and ultimately customer satisfaction.

Long term incentive is provided through Fortis Inc. stock based compensation[48]. The stock based compensation is funded by the shareholder and is not included in the cost of service.

3.3.3.2 M&E Employees

As a general policy, FEI establishes base salary and incentive compensation targets at the median level of a peer group of companies. The peer group is representative of a commercial/industrial group with an emphasis on natural resources and utilities. Pay increases and incentive opportunities for all employees are linked to individual and company performance. FEI also offers an employee benefits program for M&E employees comprised of pensions, health and welfare benefits. The employee benefits program is targeted to be competitive at the median level of an established group of comparator companies.

A key objective has been to provide a common benefits platform for all M&E employees in the gas and electric utilities. This strategy serves two purposes: 1) it simplifies administration and enables greater negotiating power with third party providers and 2) it supports internal transfers between the utilities and departments facilitating development and growth.

3.3.3.3 Unionized Employees

FEI has diverse employee groups that are influenced by job family, geography and industry. Recent agreements with the IBEW and COPE focus on competitive rates of pay, productivity, retention of management rights and cost effectiveness. Negotiated settlements that include general wage increases also include saving offsets in other compensation and benefit areas.

The IBEW and COPE pension plan is a jointly trusted, cost-shared defined benefit pension plan. As with M&E employees, FEI has made considerable progress in negotiating harmonized benefit plans for active IBEW and COPE employees.

3.3.3.4 Labour and Benefit Inflation

Labour and benefit inflation are primarily non-discretionary costs required to fund expected wage and benefit increases for our employees. In all departments, the forecast labour inflation and benefit loadings have been applied to the forecast labour force for 2013. Since this has been a consistent practice across all departments, the labour and benefit inflation category is not specifically addressed in each departmental discussion, but is instead included here as applicable to all departments. For forecasting purposes, employee labour and benefit costs are calculated and expressed as a percentage of total available employee labour dollars for determination of labour charge-out rates. In this fashion, increases in labour and benefits are allocated between O&M and capital, based on the chargeable hours forecast against O&M and capital activities. Within the O&M tables in this section, only the O&M portion of labour and benefit increases has been captured. The capital portion of the increases is captured in the capital expenditures found in Section C4.

[48] Stock based compensation includes stock options and Performance Share Units (PSUs).

The department forecast of O&M labour inflation and benefit increases for 2014 - 2018 are shown in the following table.

Table C3-3: Forecast Labour and Benefit Inflation ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Operations	1,112	1,032	1,295	1,443	1,941
Customer Service	529	491	616	686	923
Energy Solutions & External Relations	307	285	357	398	536
Energy Supply & Resource Dev	90	83	104	116	156
Information Technology	210	194	244	272	366
Engineering Services & PM	311	289	363	404	544
Operations Support	243	226	283	316	425
Facilities	44	41	52	58	78
Environment Health & Safety	37	34	43	48	65
Finance & Regulatory Services	181	168	211	235	316
Human Resources	151	140	175	195	263
Governance	-	-	-	-	-
Corporate	4	4	5	5	7
	3,219	2,988	3,748	4,177	5,619
Annualized Labour and Benefit Inflation	2.4%	2.2%	2.6%	2.8%	3.7%

A discussion of the labour inflation forecasts and the benefit inflation forecasts follows.

3.3.3.4.1 LABOUR INFLATION

This paragraph redacted and filed confidentially under separate

3.3.3.4.2 BENEFIT INFLATION

Employee benefits include workers' compensation, long term disability, extended health and dental benefits, group life, Medical Services Plan, Canada Pension Plan, Employment Insurance, employee savings plans, employee incentive plans, share purchase plans, pension and other post-employment benefits (OPEB). Benefit costs, other than pension and OPEB, tend to be relatively consistent with annual increases generally tracking inflation or in the case of some health related benefits, slightly higher.

Pension and OPEB expenses, due to their impact on total benefit costs and the changes being experienced, warrant separate discussion. Pension and OPEB expenses are based upon actuarial estimates provided by the Company's actuaries, Towers Watson and Morneau Sobeco. Both firms have provided actuarial services to FEI for more than twelve years and are very knowledgeable about FEI's pension plans and actuarial forecasting.

The Pension and OPEB expense for 2013 Approved, 2013 Base and the 2014-2018 Forecast, as well as the allocation between O&M and Capital are included in the table below.

Table C3-4: Pension and OPEB O&M and Capital Forecasts

	2013 Approved	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Pension & OPEB Expense							
2013 Allowed	17,485						
True up to revised Actuarial		12,607	(1,426)	(1,954)	(1,221)	(894)	868
Pension & OPEB Expense	17,485	30,092	28,666	26,712	25,491	24,597	25,465
Pension & OPEB allocated to Capital							
2013 Allowed	1,847						
Accounting Change (retiree portion)		930					
True up to revised Actuarial		2,002	(226)	(266)	(135)	(74)	415
Pension & OPEB allocated to Capital	1,847	4,779	4,553	4,286	4,151	4,077	4,492
Pension & OPEB allocated to O&M	15,638	25,313	24,113	22,426	21,340	20,520	20,973
Incremental O&M Impact		9,675	(1,200)	(1,688)	(1,086)	(820)	453

Pension and OPEB expense has been and will continue to be a significant challenge in managing increases in costs for FEI. For 2013, the actuarial estimate that was recently completed is more than 70 percent higher than the actuarial estimate that was done in 2011 to support the 2012-2013 RRA forecasts and approved amounts. The difference between these two amounts is captured in a deferral account in 2013 for recovery from customers in future rates.

3.3.4 Customer Focus

Strengthening customer focus remains a high priority for the Company as it focuses on serving customers and responding to their new demands. The Company continues its efforts to enhance service delivery performance by building on recent achievements and operational enhancements. A number of these initiatives are discussed in Section A of the Application.

The Company's ability to retain and attract customers is influenced by its challenging and competitive market environment. To focus on increasing customer retention and capture rates, FEI will undertake activities such as increased education and awareness to help customers understand the benefits of natural gas use and to encourage the efficient use of energy.

Additionally, affecting O&M costs is the need to strengthen customer awareness and encourage customer participation in our natural gas base business including safety awareness issues, energy efficiency and conservation, renewable natural gas, natural gas for transportation, and liquefied natural gas opportunities.

Discussion of these drivers is included in the various departmental reviews, where the following customer-driven initiatives are highlighted:

- Maintaining the customer safety focus and emergency response;
- Maintaining the gas system for our customer base;
- Maintenance or improvement of customer satisfaction levels;
- Enhancing the meter reading and customer contact processes;
- Providing more self-serve options to our customers;
- Increasing our interactions with customers;
- Addressing increased call volumes, capital and engineering support, postage and meter reading costs related to customer growth;
- Initiatives to retain existing customers, attract new customers, and maintain throughput on the system;
- Providing new service offerings;
- Improving processes for customers through reducing wait times and providing them with tools to better understand their energy options;
- Continuation and modification of EEC programs, including high carbon fuel switching;
- Providing customer education and outreach on the benefits of natural gas;
- Advancing natural gas end use technologies; and
- Improvements to the BC One Call process and enhancements in systems to improve location of underground gas lines for customers.

3.3.5 Productivity

As discussed in Section A3, a priority for the Company and its employees is to improve productivity and realize efficiencies in its operations. In identifying O&M forecasts over the PBR Period, departments were encouraged to review processes and identify potential sustainable savings by streamlining processes, leveraging technology and optimizing opportunities for integration with the Electric business. Department O&M requirements over the PBR period have been developed with this productivity focus challenge in mind. As discussed in Section A, future integration opportunities are expected to be more complex and dependent on the Company's ability overcome challenges around union issues and IT platforms and differences in the nature of the gas and electric operations. While no specific incremental savings have been identified, the productivity focus has served to manage the number of pressures put forward requiring incremental funding.

3.3.6 Demographics

Continued focus is required to recruit, develop, transition, and manage overall changes to the composition of FEI's workforce in the coming years. A five year workforce plan was submitted to the BCUC on August 1, 2012 for the FEU. This section is consistent with this five year workforce plan, summarizes the challenges of the aging workforce and describes the actions, practices and measures that the Company is using to prudently manage the demographic transitions.

Between 2013 and 2018, 552 employees, or roughly 24 percent of the total employee population of the combined gas and electric utilities are eligible to retire with unreduced pensions. When including the 357 employees also eligible to retire with reduced pensions, the total number of employees eligible to retire (unreduced and reduced pensions) increases to 909 or 39 percent of the current workforce.

It is difficult to forecast the actual number of employees who will retire when they become eligible. While many retirements are anticipated, the actual experience of the Company over time has been less. Between 2008 and 2012, only 14 percent of those eligible to retire with a reduced or unreduced pension exercised their retirement option.

FEI in-demand skill positions which require focus are:

- Mid-Level Managers
- Engineers
- Planning and Design Technicians
- Corrosion and Control Technologists
- SAP Information Technology Roles
- Gas Controllers

FEI's activities to address the demographic transitions can be categorized into the below areas:

1. Workforce planning activities
2. Prioritization and targeted recruitment of key roles
3. Development of internal talent pools

These activities are explored in more detail below.

3.3.6.1 Workforce Planning

FEI continues to engage in workforce planning by assessing factors including: forecasting eligible retirements; projecting the probability of actual retirement rates experienced and assessing the degree of risk relative to identified specialized skill sets. This helps to mitigate the exposure to high numbers of retirements.

HR works with business units to:

1. Identify and monitor retirement eligibility – identify and monitor potential loss of skills due to possible retirements. Plans are adjusted accordingly, and talent sourcing strategies and tactics are developed.
2. Prioritize and target key roles – Develop contingencies for how key roles will be performed in the future with potentially fewer and weaker skill sets. This analysis identifies priorities for training program development and job design.

3.3.6.2 Targeted Recruitment

To hire difficult to fill and in-demand skill positions FEI leverages relationships with external groups and associations including:

a) Recruiting young workers for engineering and technology co-op positions;
b) Strengthening partnerships with colleges and universities to increase the ability to fill difficult to recruit positions in the engineering, finance, and technical fields;
c) Recruiting through engineering and technology associations; and
d) Partnering with new immigrant organizations.

FEI continues to focus on filling positions with internal talent. This creates development opportunities which increase employee engagement and ultimately productivity. FEI continues to match skills, abilities and career goals with available opportunities.

3.3.6.3 Developing Internal Talent

FEI is focusing development programs on general leadership, technical and engineering skills. Each of these areas is explored in more detail below.

Leadership Development

The Company's leadership development will continue to focus on the delivery of targeted development programs and the identification of top talent.

Leadership and supervisory training courses continue to be delivered in a measured and integrated fashion, using both internal and external resources. The objective of these programs is to develop leadership and supervisory competencies transferrable through the businesses.

HR continues to work with individual leaders and supervisors to tailor development plans. Course offerings vary from the essentials of leadership to more specific skills such as coaching and leading through change. First time managers are provided with targeted supervisory training.

Technical Trades and Engineering

Engineering and trades development programs remain a priority.

Technical Trades programs include in house training, external training and on-site reinforcement. Continued focus of competency based apprenticeship and apprenticeship style programs for the main gas field Operations streams (construction, customer service and station maintenance) remains a priority.

The Engineer in Training (EIT) program selects engineering graduates and rotates them through a variety of work experiences exposing them to different facets of the Company's operations. This is done to support EIT's work towards accreditation as professional engineers and expedite their development in the gas utility industry.

3.3.6.4 Conclusion on Demographics

Workforce planning practices will continue to evolve and respond to labour market realities to ensure the Company has a skilled workforce able to meet business demands. The Company believes the actions and activities described above appropriately address the demographic realities and position FEI to continue to deliver on its service levels.

3.3.7 System Reliability and Safety

Many of the costs incurred in the Operations, Resource Development, Operations Support, Engineering Services, Facilities and EH&S departments are driven by system reliability and safety requirements. In particular, the Company has an ongoing requirement to comply with existing as well as anticipated or changing codes and regulations. The *UCA*, *Oil and Gas Activities Act, Worker's Compensation Act, Environmental Assessment Act, Safety Standards Act*, fire codes and safety standards, Provincial and Federal Emergency Acts, Canada Standards Association Codes, such as CSA Z662, and other standards such as ISO 14001 and Measurement Canada SS-06, are some of the key codes and legislation with which the Company must be in compliance. These codes and regulations have a strong focus on public, employee, property, and environmental safety and system reliability. A variety of external agencies oversee the Company's response to these codes and regulations, to which FEI has a solid track record of compliance.

Discussion of these system reliability and safety drivers is included in the various departmental reviews, where the following initiatives are highlighted:

- Right of way, depth of cover and maintenance programs;

- Evolving engineering standards;
- Changes to the meter recall program;
- Changing codes regarding LNG;
- SCADA (Supervisory Control and Data Acquisition) enhancements;
- System reliability infrastructure projects to access cost effective supply over the long term and maintain access to natural gas supplies at fair market prices;
- Increasing levels of First Nations and public consultation;
- Capital support requirements for sustainment projects that are discussed in Section C4;
- Evolving in-line-inspection technologies;
- New practices for corrosion management;
- Changes to building codes; and
- Worksafe BC regulations.

3.3.8 Forecast O&M by Department

The table below provides the forecast O&M expense by department at a high level for the PBR Period, on a comparable basis to the 2013 Base. A discussion of the trends in each department follows.

Table C3-5: Departmental O&M Forecasts ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Operations	69,016	71,062	73,298	75,084	77,253	79,648
Customer Service	44,398	45,353	46,323	47,873	49,068	50,956
Energy Solutions & External Relations	20,721	23,275	23,771	24,343	24,961	25,721
Energy Supply & Resource Dev	4,440	4,738	4,918	5,040	5,175	5,350
Information Technology	23,768	24,392	24,911	25,487	26,097	26,809
Engineering Services & PM	17,018	17,736	17,766	18,214	18,692	19,325
Operations Support	13,111	13,698	14,013	14,386	14,794	15,313
Facilities	9,504	9,959	10,170	10,469	10,705	11,065
Environment Health & Safety	2,872	2,934	2,997	3,069	3,147	3,242
Finance & Regulatory Services	15,079	15,401	15,728	16,101	16,502	16,987
Human Resources	9,192	9,399	9,601	9,841	10,102	10,431
Governance	8,028	8,371	8,742	9,135	9,544	9,974
Corporate	(6,161)	(6,385)	(6,478)	(6,600)	(6,726)	(6,914)
	230,985	239,933	245,761	252,443	259,315	267,907

3.4 *OPERATIONS*

3.4.1 Description of Operations Department

The Operations department is responsible for installing, operating and maintaining the gas distribution and transmission (pipelines) systems and plant assets in order to provide safe, reliable and cost effective service to customers. The department has three major groups, described in further detail below:

1. Distribution;
2. Transmission (Pipelines); and
3. Plant Operations (LNG and Compression).

Operations field personnel and management are distributed throughout the FEI service territory. Field personnel are trained and equipped with tools, equipment and vehicles to provide emergency response, operate and maintain the gas distribution system, pipeline system and plant assets and to perform installations, renewals and system improvements. Operations office personnel are responsible for planning, resource management, scheduling, dispatching and closing. Contractors are used to complement Company resources.

3.4.1.1 Distribution

Distribution is responsible for operating and maintaining the geographically dispersed network of distribution system piping and performs four main functions described below.

- Emergency Management includes providing first response for public, asset and employee safety. The activities include first response to system damage, gas odours, fire and carbon monoxide calls, emergency prevention through public education, and maintaining stand-by resources. Emergency response personnel and resources are mustered throughout FEI's service area to provide timely response to emergencies.
- Installations and Renewals includes installing and renewing mains, services, meters, stations and other assets to add new customers and improve system reliability, integrity and capacity for all customers. Renewals are replacements of the gas system components generally due to condition, age, technology and obsolescence to improve system reliability, integrity and capacity. Although employees routinely perform these activities, a significant portion of installation and renewal activity is performed by external contractors, particularly during periods of high customer additions activities.
- Operations and Maintenance includes scheduled and unscheduled operating and maintenance activities dedicated to mitigating operating risks and preserving the safety and reliability of the distribution and transmission systems. Activities include system inspection, leak survey, pipeline and right-of-way patrols, preventive and corrective maintenance of equipment, valves, stations and meter sets. The level of activity required

is influenced by code and standard requirements (i.e. Canadian Standards Association or CSA), regulatory requirements, operating and asset conditions.

- Account Services work performed by Operations includes premise calls, meter lock-offs, unlocks and reactivations, meter exchanges/renewals and other customer inquiries requiring a field workforce response. An example of this is a high bill complaint initiated by a customer which results in a visit to the customer's premise to ensure the meter is functioning correctly.

3.4.1.2 Transmission (Pipelines)

The Transmission group is responsible for operating and maintaining the pipelines and right-of-ways. The group ensures that the FEI transmission or pipeline system can deliver gas from interconnecting pipelines or the Tilbury LNG facility to the gate stations operated by Distribution to FEVI and Burrard Thermal, and to a number of industrial customers in a safe and reliable manner. The Company's pipeline system includes the Interior Transmission System mainline, Southern Crossing Pipeline, Coastal Transmission System and some transmission pressure lateral pipelines.

The group is responsible for management of pipeline right-of-ways including maintaining signage and demarcation to help prevent third-party damage, removing right of way encroachments, and controlling vegetation to maintain visibility of right-of-way boundaries.

3.4.1.3 Plant Operations

Plant Operations provides the function and supporting facilities that allows the FEI transmission system to deliver natural gas to gate stations for distribution or to a number of industrial customers and FEVI. Plant Operations is comprised of two groups: Liquefied Natural Gas (LNG) and Compression.

FEI operates an LNG facility at Tilbury Island (Delta). Its main function is to provide peaking gas supply to the Lower Mainland as part of a supply portfolio that provides a reliable and secure supply of natural gas for the Company's customers. The facility also provides emergency gas supply during periods when regular supply from pipelines is deficient. The operation involves liquefying natural gas during off-peak periods and storing it for peak period use. The process of peaking use involves re-gasifying the liquid, odorizing the gas and compressing it for re-injection into the transmission system.

FEI filed an application to provide a permanent offering under Rate Schedule 16 to offer sales of surplus LNG for heavy transport applications, and has included the LNG costs that are necessary, including electricity to facilitate the liquefaction process, to provide this service in its forecasts. FEI received Commission Order G-88-13 on June 4, 2013. FEI may update the O&M related to Rate Schedule 16 in an evidentiary update to this Application once the Rate Schedule 16 decision has been fully evaluated.

The Company operates compressor stations throughout its service territory to allow gate stations and customers with natural gas at adequate pressures. The function of compressor stations is to increase the gas pressure in the system to allow greater flow of gas in the transmission system. The operation of compressor stations is based on system load requirements and as such, most stations are only used for peak periods. Compressor stations are also used to support the transmission system during pipeline outages, emergency conditions or for third party gas transportation.

3.4.2 Business Drivers for Operations Department

The main business drivers of O&M costs in Operations are:

- the number of customers, and the size and condition of the gas system and assets,
- codes and regulations required for safe operations,
- employee demographics,
- electricity and fuel usage for plant operations, and
- inflation on employee wages, salaries and vehicle costs.

3.4.2.1 Customers, System Size and Condition

The number of customers has an impact on the number of calls handled by technicians and the amount of assets such as meters that need to be maintained. The size and condition of the system also drives the amount of operating and maintenance activities that must be performed. At some point, gas system assets including distribution pipe, transmission pipelines and customer meters must be repaired or replaced as identified by regularly scheduled inspections and assessments of conditions. As the system grows and ages additional resources are required to operate, assess and maintain the system.

Other examples of costs that vary based on the size and condition of the system are routine meter exchanges for all customer classes, above and below ground valves that need to be maintained, pressure regulating stations that need to be inspected and the below ground piping system which must be regularly surveyed for leaks. Also, customers regularly call regarding concerns ranging from emergency type activities such as gas odours to financial type activities such as billing inquiries.

3.4.2.2 Codes and Regulations

Laws, code requirements and accepted industry operating practises are also major drivers of Operations costs. For example, Measurement Canada, the regulatory body for meter accuracy, works with industry to establish compliance sampling and testing for various meter types.

3.4.2.3 Aging Workforce/Training

Employee demographics also continue to be a driver of costs in Operations. Since 2007, the Company has hired Distribution Apprentices (96) as part of its resource plan to respond to challenging demographics in the field workforce. Classroom and on the job training is extensive for the apprentices in order to adequately prepare them to be able to respond to gas emergencies as well as to perform construction and customer service duties and replace experienced employees as the latter retire. Customer satisfaction levels for field work, in particular gas odour response, meter exchange and service installations, are high, and Operations plans to maintain or improve on these levels even as the existing experienced workforce evolves through regular retirements.

About two thirds of the operating budget is labour cost. Field workforces are distributed throughout the service territory. They are a highly skilled workforce equipped with vehicles, tools and equipment to perform the plant operation and maintenance functions including responses to emergency calls. As the workforce is fairly mature, it is expected that retirements will continue to occur steadily over the five-year PBR Period and that the Company will face continued pressure on costs for employee training and knowledge transfer. Due to increased demand for skilled workers in the Province, the Company also expects that attraction of qualified trade workers will be more difficult. An in-house apprenticeship program is required to maintain a steady stream of replacements, a stable and competent workforce and a commitment to customer satisfaction.

3.4.2.4 Fuel Gas and Electricity

The primary drivers for Plant Operations, LNG and compression facilities are labour, fuel gas and electricity. Fuel gas is used to run drivers for compressor units and to provide heat for the vaporizers at the LNG plant. The fuel gas usage for compressor units or vaporizers is system load dependant and highly variable. System load variability is mostly weather dependant and an accurate forecast of fuel requirements is difficult. The fuel gas forecast is based on historical requirements for average annual conditions, used together with forecasted gas prices. Electricity is used to run equipment at the LNG plant during periods of liquefaction and to power the unit at the Hedley Compressor Station. Similarly to fuel gas use, the use of electricity is highly variable and the forecast is based on historical requirements for average annual conditions and forecasted electricity prices.

3.4.2.5 Inflation (Wages/Salaries and Vehicles)

The Operations group in FEI consisted of approximately 570 employees and 400 vehicles at 2012 year-end. Wages and salaries are two-thirds of the annual Operations O&M budget, while vehicle costs represent another 5 percent. Negotiated contractual wage and salary increases between 2 percent and 3 percent per annum historically, together with annual contractual step increases for newer COPE employees or IBEW Distribution Apprentices and pension/benefit adjustments for all affiliations represent the largest component of annual incremental changes. Rising vehicle operating costs, particularly fuel, also impact the overall Operations O&M costs.

3.4.3 Operations Review

Table C3-6 sets out the historical O&M for Operations. Overall, the 2013 Projection is in line with the 2013 Approved, with only a 0.5 percent increase.

Table C3-6: Operations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 36,643	$ 37,642	$ 39,897	$ 42,141	$ 44,432
Non-Labour	17,801	18,114	19,909	21,368	18,757
Total O&M	$ 54,444	$ 55,756	$ 59,806	$ 63,509	$ 63,189

The table above shows an increasing trend in O&M labour costs due primarily to annual wage/salary inflation, adjustments to benefits and pensions and increases in field activities. The non-labour costs (contractors, vehicles, materials, etc.) also show an increasing trend which is due to inflation, scope and resourcing changes for various activities.

Operations regularly reviews maintenance programs and schedules for assets with a view to managing risk and reliability, optimizing resources and budgets. Operations has limited if any opportunity to realize benefits through integration with the electric utility. There is only a small portion of field employees in the overlapping electric service territory and they are primarily skilled in working with and around gas and are needed primarily to maintain emergency and core footprints in the gas service territory. The field workforces also work with two very different products (gas versus electricity) and as such require different certifications, education and skillsets. Similarly, technical office roles, such as planners, specialize in designing gas or electric systems. In the limited areas of work where there are similar skillsets required, Operations will pursue synergies and cost effectiveness through integration and adoption of best practices.

The Operations department has been segregated into the three main groups (Distribution, Transmission and Plant Operations) and each of these areas is discussed below.

Distribution

Table C3-7 sets out the historical O&M for the Distribution group.

Table C3-7: Distribution O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 31,188	$ 32,050	$ 34,021	$ 35,987	$ 38,062
Non-Labour	9,802	9,814	11,659	12,308	10,573
Total O&M	$ 40,989	$ 41,864	$ 45,680	$ 48,295	$ 48,635

For the period 2010 to 2012, the Distribution cost pressures were from wage, salary and vehicle inflation, corrective work, (residential meter regulators and bridge crossings), emergency standby (due to weather, labour relations / work continuance planning as well as a slowdown in customer driven work in the Interior South region) and unscheduled meter exchanges. In 2012, Distribution completed all of its commitments which were approved as part of the 2012-2013 RRA. Partially offsetting the cost pressures, particularly in 2012, Distribution realized savings in IBEW training costs as well as reductions in back office positions, several management positions and travel expenses. The savings in IBEW training costs of $750 thousand was the most significant item and one that is expected to be sustainable through the PBR Period. The training efficiencies were gained through the adoption of a peer training and competency assessment training model as well as fewer new hires in 2012 and greater use of e-learning tools.

For Distribution, the 2013 Projection closely approximates the 2013 Approved. These costs are necessary to meet departmental initiatives and program commitments which include:

- Code Compliance – FEI's goal of providing safe, reliable, cost effective and environmentally responsible service is strongly aligned to code requirements. For example, in order to meet CSA Z662, pipeline right-of-way markers will continue to be changed from orange to yellow until full compliance is achieved.
- Demographics - The peer training model (where subject matter expert employees are utilized to train new and existing employees) has been effectively implemented and administered resulting in sustainable lower overall IBEW training costs. Operations is exploring opportunities to expand this model to Transmission field employees. New employees (Distribution Apprentices) will be hired in 2013 to fill vacancies created as a result of retirements and these new employees will learn and develop their skills through the peer training model.
- Operations Centre – the approved planners and operations support representatives have been used effectively to execute the required work scope.
- Field Service Delivery – The primary categories of work are: Preventative Maintenance, Corrective Maintenance, Operations, Meter Exchange, Emergency Management and Meter to Cash. Field Service Delivery is the largest component of the Distribution budget and activities are based on a combination of historical and scheduled maintenance programs.
- Labour versus Non-Labour – The Projected 2013 shift of Distribution group O&M labour to non-labour resources of approximately $1.8 million reflects expected use of contractor resources in 2013 and the level of actual internal and contractors resources used in 2012. Contractors are used where in-house expertise is not readily available and for some seasonal work activity like vegetation management and bridge crossing repairs. For some Distribution operations activities such as leak survey, physical locates, and meter work, trained contractor resources are interchangeable with internal labour and

are used to balance work requirements depending on internal vacancies, volume of work, and availability.

Transmission

Table C3-8 sets out the historical O&M for Transmission:

Table C3-8: Transmission O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 2,578	$ 2,789	$ 3,133	$ 3,082	$ 3,395
Non-Labour	4,432	5,420	5,984	6,287	5,408
Total O&M	$ 7,010	$ 8,209	$ 9,117	$ 9,369	$ 8,803

In 2012, Transmission O&M increased by $900 thousand as compared to 2011. This is a result of increased pipeline and right-of-way activities, primarily vegetation management and pipeline marker replacements. Both activities are required on an on-going basis to maintain visibility and access to the pipelines so that regular line patrols can be conducted efficiently, third parties are aware of pipeline location and crews can access these areas for repairs. The pipelines are critical sections of infrastructure allowing for gas to be delivered reliably to customers.

The 2013 Projection is approximately $600 thousand higher than the 2013 Approved due to increased costs forecasted to meet code compliance for right of way and depth of cover management. The vegetation management activities on the right-of-ways are for removal of historical large growth vegetation. Also, pipelines must be compliant with industry code in terms of depth of surface cover and recent surveys in various Interior locations have revealed some deficiencies in this regard which must be remedied. Both issues are on-going and expected to continue to require resources and funding over the PBR Period.

Plant Operations

Table C3-9 sets out the historical O&M for Plant Operations:

Table C3-9: Plant Operations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 2,877	$ 2,803	$ 2,743	$ 3,073	$ 2,975
Non-Labour	3,568	2,880	2,265	2,773	2,776
Total O&M	$ 6,444	$ 5,683	$ 5,009	$ 5,845	$ 5,751

In 2012, Plant Operations O&M decreased by approximately $700 thousand as compared to 2011. This was due to reduced operating costs for compression including lower utility costs at

Interior compression sites and the occurrence of some one-time cost items in 2011 (Kitchener station roof replacement, competency management initiative and an employee relocation).

The 2013 Projection for Plant Operations is reflective of future on-going operating and maintenance costs and closely aligns to the 2013 Approved, increased only for an operator at the LNG facility to manage the demographic/training challenge at the facility over the PBR Period.

Operations Review Summary

In summary, the Projected Operations O&M is in line with the Approved O&M and the various groups within Operations are meeting their 2012 and 2013 commitments. Operations have delivered safe, reliable service to customers and will continue to look for productivity and efficiency opportunities to mitigate the impact of wage/salary inflation. The department has focused on increasing operating productivity, realizing sustainable cost savings, managing risk and workforce demographics and maintaining emergency response times. Emergency response times to all types of gas emergencies have been consistently maintained and continuous safe delivery of gas to customers speaks to the reliability of the FEI gas distribution network and the supporting Operations maintenance and operating programs.

3.4.4 Operations Forecast

Table C3-10 below sets out the 2013 Base and the high level 2014-2018 operating and maintenance forecasts for Operations. The reconciliation of the 2013 Projection to the 2013 Base for Operations is provided in Table C3-2. The forecast O&M expenditures are required to operate the gas system and meet program commitments. The forecast reflects the scope of work that is anticipated for the PBR Period and the known pressures from changes to the meter recall program and LNG production. Any additional code changes or changes in the scope of Operations type activities will drive incremental costs that the Company will need to offset with productivity realizations.

Table C3-10: Operations O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 47,511	$ 49,035	$ 50,313	$ 51,617	$ 53,153	$ 55,182
Non-Labour	$ 21,504	22,027	22,985	23,467	24,100	24,466
Total O&M	$ 69,016	$ 71,062	$ 73,298	$ 75,084	$ 77,253	$ 79,648

Overall, Operations is forecasting increases in labour costs due to the labour and benefit inflation discussed in Section C3.4. Approximately 69 percent of the 2013 Base Operations O&M is employee wages and salaries subject to inflationary pressures. The forecast also includes non-labour inflation of approximately 2 percent. The Operations forecast is further segregated into the three main groups (Distribution, Transmission and Plant Operations) and each of these areas is discussed below.

Distribution

Forecast O&M for the Distribution area is shown in Table C3-11 below.

Table C3-11: Distribution O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 40,562	$ 41,849	$ 42,756	$ 43,868	$ 45,190	$ 46,932
Non-Labour	12,387	12,433	12,694	12,961	13,233	13,511
Total O&M	$ 52,949	$ 54,282	$ 55,450	$ 56,829	$ 58,423	$ 60,443

In 2014, over and above inflation, the Distribution group is showing a pressure in field activities of $150 thousand, due to forecast increases to residential meter exchanges, as a result of Measurement Canada changes effective January 2014 prevailing throughout the PBR Period. Lastly, the Operations Centre is forecasting additional planner and support resources in 2017 and 2018 to meet the resource requirements of the capital plan.

Transmission

Forecast O&M for the Transmission area is shown in Table C3-12 below.

Table C3-12: Transmission O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,486	$ 3,570	$ 3,648	$ 3,745	$ 3,854	$ 4,000
Non-Labour	6,327	6,448	6,583	6,721	6,862	7,006
Total O&M	$ 9,813	$ 10,017	$ 10,231	$ 10,466	$ 10,716	$ 11,007

Transmission is not forecasting any incremental labour or non-labour increases other than inflation. Any additional code changes or changes in the scope of Transmission activities will drive incremental costs that the Company will need to offset with productivity realizations.

Plant Operations

Forecast O&M for the Plant Operations area is shown in Table C3-13 below.

Table C3-13: Plant Operations O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,463	$ 3,617	$ 3,910	$ 4,004	$ 4,109	$ 4,250
Non-Labour	2,790	3,146	3,708	3,785	4,005	3,949
Total O&M	$ 6,253	$ 6,763	$ 7,617	$ 7,789	$ 8,114	$ 8,199

In addition to inflation, Plant Operations is forecasting some other incremental costs. In 2014 and 2015 there are incremental labour and non-labour LNG production costs forecast in Plant Operations ($376 thousand and $713 thousand respectively) to support the revenues from the incremental Rate Schedule 16 volumes[49], which were discussed in the Rate Schedule 16 Amendment Application. Unrelated to Rate Schedule 16 activity, the Plant Operations group is also forecasting an incremental one-time non-labour pressure in 2017 for LNG storage tank re-coating. Any additional code changes or changes in the scope of Plant Operations activities will drive incremental costs that the Company will need to offset with productivity realizations.

3.4.5 Operations Summary

In conclusion, Operations is committed to delivering natural gas safely, reliably and cost effectively to all customers. Operations plans to continue to pursue opportunities for increased productivity by exploring any potential benefits of integration and further automation of business processes without deteriorating service. The forecasts reflect the scope of work that is anticipated for the PBR Period and the known pressures. Any additional code changes, changes in the scope of Operations type activities or above forecasted inflationary increases will drive incremental costs that the Company will need to offset with productivity realizations.

3.5 *CUSTOMER SERVICE*

3.5.1 Description of Customer Service Department

The Customer Service department is responsible for providing accurate and timely billing for customers, for ensuring that meters are read regularly and accurately, for providing effective and timely resolution of customer inquiries, and for providing customers with energy consumption information. The department also oversees mass market customer communications regarding accounts and billing, administers the Customer Choice program, performs market research and analysis, oversees mass market bad debt management, works to swiftly resolve customer issues raised to third parties including the BCUC, Better Business Bureau and Provincial MLAs, and provides contact centre services for customer construction requests including new service line installations, service alterations and abandonments through its Construction Services Contact Centre.

FEI successfully completed the stabilization phase of the CCE Project in the second quarter of 2012. The CCE Project was delivered on-time and under budget, with the transition to internally-delivered customer service operations going live as planned on January 1, 2012. Final project costs were $109 million as compared to a budget of $115 million, a significant savings achieved while still meeting commitments on the timeline and project deliverables. During the first year of operations, the FEU were able to deliver on customer service level commitments and make

[49] Pursuant to Commission Order G-88-13 received on June 4, 2013, O&M related to Rate 16 may be updated in an evidentiary update to this Application once the Rate Schedule 16 decision has been fully evaluated.

improvements to services while achieving cost savings over and above what was committed to in the 2012-2013 RRA.

Regarding the implementation of the CCE Project, on pages 52 and 53 of the 2012-2013 RRA Decision, and in Directive No. 13 Page 3 of Appendix A, the Commission Panel stated

> *"The Panel expects the FEU to address the matter of leveraging the Customer Care function to maximize productivity opportunities in the next revenue requirements application. This should provide ample time for stabilization of the system and a better understanding of potential opportunities."*

FEI has provided information on its productivity focus both in Section A3 of this Application, and also in this section. In summary, FEI has:

1. Realized a sustainable reduction in O&M from the 2013 Approved to the 2013 Projection of $10.6 million (of which $8.6 million is from a new meter reading contract);
2. Realized a permanent reduction in staffing levels from the 2013 Approved to the 2013 Projection;
3. Introduced automated calls and managed the timing of outbound calls to better utilize resources in the call centres;
4. Changed the collection process so that customers receive automated calls reminding them of their overdue bills;
5. Replaced meter exchange letters with a live agent call, resulting in higher customer satisfaction as their concerns are able to be addressed immediately, and increased utilization of employees' time as the live agent call results in home owners being more likely to be home when relights are required;
6. Increased the use of self-serve options for customers leading to more efficient use of call centre resources;
7. Negotiated a new meter reading contract that not only reduces costs for customers, but results in monthly meter reads, eliminating the need for bi-monthly estimates, has allowed for the optimization of a "gas only" meter reading route, and additional services for off-cycle reads; and
8. Adopted the insourced customer service model which has allowed for greater integration with other departments of the FEU. This has resulted in more timely resolution of complex billing issues and rapid response to escalated complaints, improved understanding of customer communication, faster resolution of new construction and meter installation inquiries, and greater understanding by customer service staff of actual operational issues faced by our customers.

In future, customer service operations will improve its efficiency by bringing more work into the contact centre from other parts of the organization during times of low call volumes and will investigate changing the hours of operations.

Although call volumes during 2012 were relatively close to forecast, total interactions with our customers were higher than forecast. Despite this, the FEU were able to achieve cost savings over and above what was committed to in the 2012-2013 RRA and still maintain acceptable, and in some cases improved, service levels. These cost efficiencies have been built into the Customer Service department and therefore will be sustained for customer benefit into the coming years.

During the first two years of operations, the Customer Service department has been recording variances from approved budgets for the contact centres, billing operations, customer relations, and meter reading costs into the approved Customer Service Variance Account. The balance of this account at the end of 2013 is forecasted to be approximately $13 million on an after-tax basis, a savings that will be passed on to the customers to mitigate future rate increases.

A measure that the Company is now able to monitor to assess productivity in our contact centres is cost per interaction. With this measure, the total interactions that customers have with the contact centre are compared to the cost of operating the contact centres. The total number of interactions includes inbound calls, outbound calls, and self-serve transactions. This measure provides a comprehensive view of the total cost incurred in providing service to customers across the various service channels. Efforts in the future will attempt to enhance the adoption of more cost efficient self-serve methods of providing service to customers, which is expected to put downward pressure on cost per interaction. The Company expects that cost per interaction will be lower in 2013 than in 2012, and that this measure should be stable for the PBR Period.

The operational efficiencies gained and the solid performance during the first year of operations sets the foundation for further improvements over the next several years.

Staffing levels in the Customer Service group as of January 1, 2013 are shown in Table C3-14 below.

Table C3-14: Customer Service Staffing Levels

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Forecast
O&M FTE	30	28	299	278	284	278
Project Temporary Employees	0	329	0	0	0	13
Capital FTE	7	7	10	10	10	10
Total	**37**	**363**	**309**	**288**	**294**	**301**

The increase of 326 resources from 2010 to 2011 was required to support the transition to the in-sourced customer service delivery model. Increased efficiency in 2012 resulted in the need for 21 fewer employees than approved, despite higher work volumes than anticipated. This reduced need for resources was carried forward into 2013 and will be maintained during the PBR Period. In 2013, on a temporary basis only, 13 additional FTE were required to support the meter reading transition to the new service provider. These 13 FTE are not required in 2014 and on.

Throughout the period of 2014 to 2018, FEU expects that overall staffing levels will remain consistent with the reduced 2013 level of approximately 290 staff. However, it is also expected that the Customer Service department will become more efficient as a result of refinement in the end to end business processes and the improved ability to match resources to volumes of work.

3.5.2 Business Drivers for the Customer Service Department

3.5.2.1 Contact Centres

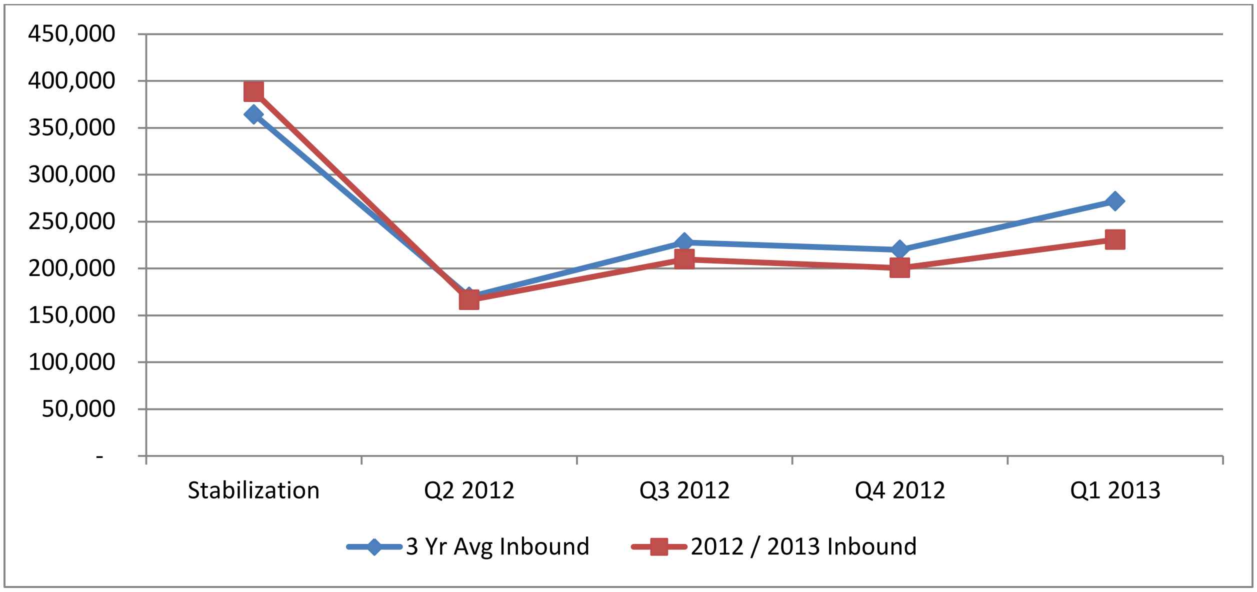
The two Contact Centres in Burnaby and Prince George are staffed to ensure customer inquiries are handled by skilled and knowledgeable staff and in a timely manner. The main driver for costs is labour, which is impacted primarily by the volume of interactions with our customers. This includes inbound and outbound calls, the Interactive Voice Response (IVR) system and account online transactions, emails and other types of correspondence.

Call Volumes

Prior to the implementation of the new Customer Service centres, FEI used 2009 call volumes (1,012,568 calls) as the basis for its estimate for 2012 and 2013 staffing levels. 2009 was the most representative of a three year call volume average for the period 2008 to 2010.

Actual inbound call volume for 2012 and the first quarter of 2013 was very close to the three year average described above as can be seen in Figure C3-1 below. The contact centres received a total of 964,987 inbound calls during 2012.

Figure C3-1: 2012 Inbound Call Volumes



Prior to 2012, the only outbound call activity was calls to collections customers prior to disconnection. During 2012, several additional outbound calls were introduced including:

- Automated reminder calls to customers with overdue bills
- Automated messages related to meter exchanges
- Live-Agent calls related to meter exchanges

These additional calls were required to improve the customer experience in both the collections and meter exchange processes. In addition, it allowed FEI to better match resources to volumes by making these outbound calls during periods of low inbound call volumes. This improvement led to increased operational efficiency as converting these calls to outbound from inbound allowed for fewer staff to be scheduled during the peak time and for staff on schedule to be more fully utilized during their entire shift.

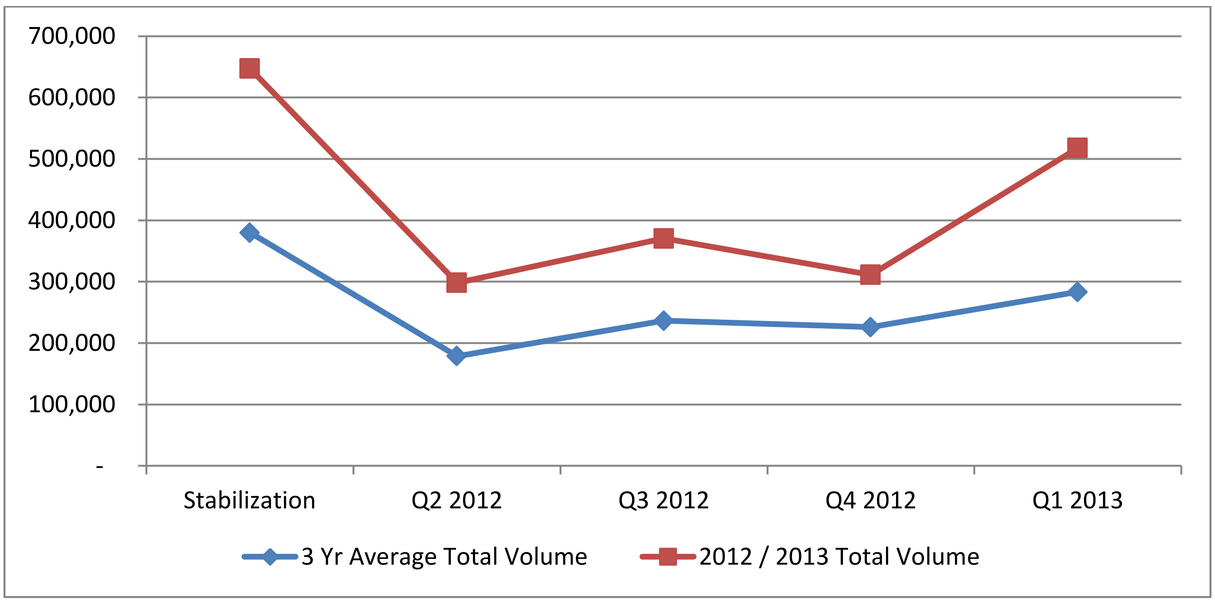
The automated reminder calls provide customers with a pre-recorded message reminding them that their payment is overdue. In 2012, approximately 530,000 of these additional reminder calls were made. As a result of these calls and other improvements made to the collections process, accounts receivable has improved and the volume of traditional outbound live-agent collections calls prior to disconnection in 2012 was reduced by 35 percent from the three year average.

An improvement was made to the meter exchange process, which utilized live-agent calls, in addition to letters, increasing outbound call volumes by approximately 36,000 calls in 2012. This process was further improved in early 2013 by reversing the order, having the live-agent call occur prior to the letter. Prior to the change, customers were sent a letter asking them to call

FEI. The live agent call has been more effective in ensuring customers understand the reason for the exchange and to find a mutually agreeable time to complete the work. In addition, it has allowed the contact centre to replace unpredictable inbound call volume with outbound calls that can be made during periods of lower inbound call volumes. This change resulted in increased customer satisfaction with the process as well as increased operational efficiency.

The total inbound and outbound call volume experienced by the contact centres in 2012 and the first quarter of 2013 was approximately 60 per cent higher than the three year average as shown in Figure C3-2 below. This additional volume was managed with lower than anticipated staffing levels and under approved budget amounts.

Figure C3-2: 2012 Total Call Volumes



Forecasted call volumes for 2014 to 2018 are expected to be similar to what was experienced in 2012 with some seasonal variances due to weather patterns, variability in gas commodity rates and general economic conditions. In addition, it is expected that there will be an increase in call volume related to customer growth and increased meter exchange activity. However, it is anticipated that this increased volume will be somewhat offset by increased use of self-serve transactions.

Self-Serve Transactions

The FEU began to offer enhanced customer communication self-serve options as part of its multichannel strategy, including web self-serve and IVR capabilities starting January 1, 2012.

Additional IVR functions that were implemented in 2012 include:

- Equal Payment Plan
  - Check eligibility
  - Enroll
- Payment Inquiry
- Create Payment Arrangements

In 2012, approximately 330,000 transactions were completed via the IVR. Additional reporting capability is planned for 2013 in order to break these transactions down into the volumes for each of these types of functions.

Additional web self-serve functions that were implemented in 2012 include:

- Register for / Establish:
  - Equal Payment Plan
  - Pre-authorized Payment Plan
  - Payment Arrangements
  - E-Bill Delivery
- Cancel:
  - Equal Payment Plan
  - Pre-authorized Payment Plan
  - E-Bill Delivery
- View meter read schedule

Web self-serve transaction volume data was collected starting in June of 2012. The total web transactions from that date to December 2012 was 54,624.

Self-serve transactions for the period of 2014 to 2018 are expected to increase slightly as customers become more familiar with the options.

Bad Debt Expense

The bad debt expense is managed by the Credit and Collections Group. The forecast estimate of $4 million annually for 2013, and for the 2014-2018 period is based on analyzing actual historical bad debt expenses to arrive at a reasonable experience rate. The experience rate was then multiplied by the forecast revenue to arrive at the 2013 and 2014-2018 forecast levels. FEU believes the historical bad debt expense is a good indicator of the expected levels.

3.5.2.2 Billing Operations

The Billing Operations group is responsible for providing accurate and timely billing for our customers, implementing and maintaining the Commission approved rates and prices and for ensuring that meters are read regularly and accurately along with the processing of payments. In addition, Billing Operations is responsible for proactively identifying potential billing issues and contacting customers to rectify issues before they are escalated.

The main drivers of cost for the Billing Operations are the number of customers, postage, printing and labour.

3.5.2.3 Meter Reading Services

Meter reading services are provided through a third party contract. FEI implemented a new manual meter reading contract in 2012 after the previous joint meter reading agreement with Accenture and BC Hydro terminated effective December 31, 2012. Effective January 1, 2013 the new provider, Olameter, began reading all FEU gas meters throughout the Province.

The new arrangement with Olameter provides a reduction in the number of bills that use estimated meter reads, and at a lower cost than the previous contract or in-sourcing. FEI expects to see cost savings of approximately $9 million annually through the PBR Period; this saving is built into the forecasts provided below. The per meter transactional cost of the services is based on a turnkey agreement that includes the technical platform and hardware required to perform the services. This ensures that the per meter transactional pricing is fixed over the first three years of the agreement. If the Company chooses to extend the agreement for an additional two years, price increases will be limited to adjustments for CPI only.

In addition to cost savings, the move to a new third party service provider also allows the FEU to focus on a “gas only” route optimization, instead of a route designed around both gas and electric customers, and will improve service for our customers.

The new contract provides for monthly meter reading and the addition of new services. Improved service for customers includes increasing meter reading frequency and providing a cost effective means for obtaining off-cycle reads. In addition to moving to a monthly read, we have also implemented additional services for off-cycle reads along with placing a notice or reminder on the customer’s door. This is used in instances where other communication channels have proven unsuccessful as well as a follow up communication to customers after an interaction.

These changes should increase customer satisfaction by reducing the number of complaints related to estimated reads as well as the number of billing adjustments required to correct historically billed estimates, although there will still be some situations where a meter cannot be read due to access issues, such as weather conditions.

3.5.3 Customer Service Review

For the O&M amounts shown in Table C3-15 below, 2010 and 2011 results were under the previous outsourced arrangement. FEI operating costs have been lower than anticipated for the first two years of the insourced customer service operation (2012 and 2013). The 2013 Projection is below the Approved amount, due to operational efficiencies gained in the first year of operations and the new meter reading contract.

The 2013 Projection of $41.825 million is $10.627 million below the 2013 Approved O&M. $10.285 million of these costs will be allocated to the Customer Service Variance Deferral Account. This is primarily due to $8.627 million in meter reading savings as discussed above, lower billing operation costs of $1.235 million as a result of efficiencies and lower print and postage and bank fees than approved, and Knowledge and Learning departmental transfer to Human Resources of $423 thousand. Total O&M after moving costs to the Customer Service Variance deferral account is $342 thousand below 2013 Approved O&M as a result of savings in research studies and bad debt expense.

Table C3-15: FEI Customer Service O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 2,085	$ 2,457	$ 18,198	$ 19,453	$ 19,577
Non-Labour	51,193	54,118	22,539	22,372	32,875
Total O&M	$ 53,278	$ 56,575	$ 40,737	$ 41,825	$ 52,452
Deferral-Labour			1,959		
Deferral-Non Labour			5,476	10,285	
Total Deferral			$ 7,435	$ 10,285	
Total O&M with Deferral	**$ 53,278**	**$ 56,575**	**$ 48,172**	**$ 52,110**	**$ 52,452**

3.5.4 Customer Service Forecast

The O&M for the Customer Service department is shown in Table C3-16 below. The reconciliation of the 2013 Projection to the 2013 Base for Customer Service is provided in Table C3-2.

Table C3-16: Customer Service O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 22,008	$ 22,537	$ 23,028	$ 23,644	$ 24,330	$ 25,253
Non-Labour	22,390	22,816	23,295	24,229	24,738	25,703
Total O&M	$ 44,398	$ 45,352	$ 46,323	$ 47,873	$ 49,068	$ 50,956

As shown in the table above, operating costs are expected to increase slightly from 2013 through to 2018. Cost increases are expected for labour and benefit inflation (Section C3.3.3), postage and expected changes to meter reading costs during the PBR Period. These increases are expected to be partially offset by the optimization of the contact centre hours of operations discussed further below.

Call volumes are not expected to vary significantly from the volumes experienced in 2012 and 2013. Although self-serve transactions are expected to increase, the impacts of a move to more self-service transactions are expected to mitigate call volume increases rather than cause decreases in volume over the period.

Although costs are expected to increase slightly over the PBR Period, customer service operations will improve its efficiency by bringing more work into the contact centre from other parts of the organization. During times of low call volumes, call centre agents will complete routine billing tasks, such as processing returned mail, filling bill history requests and updating customer contact information, which reduced labour costs in the billing department during 2012.

Service Level Changes

During 2013, the Company is planning on revising the service levels for non-emergency calls in the gas contact centres from 75 percent of calls answered in 30 seconds to 70 percent of calls answered in 30 seconds. This change will align the service levels between the gas and electric operations allowing for a better comparison between the two. In addition, there will be a labour savings associated with this change in the amount of approximately $50 thousand per year starting in 2014.

The Company does not expect a reduction in customer satisfaction as a result of this change. Research suggests that speed metrics like wait time have less importance to customers than other service factors.

Hours of Operation

The Company is planning on reviewing its core operating hours to ensure alignment with customer needs, to promote the use of self-serve options and to reduce operating costs during the PBR Period.

Despite any changes made to the general hours of operation, emergency calls will still be answered 24 hours per day, 7 days per week as they are today.

3.5.5 Customer Service Summary

In conclusion, Customer Service has delivered on all of the commitments made in the CCE CPCN and done so at a significant cost savings. These savings were achieved despite higher than forecast work volumes and a year of stabilization of the operations. Looking forward, the department plans to continue to pursue opportunities for enhanced efficiency while achieving its corporate and departmental objectives, and providing quality service to our customers.

3.6 ENERGY SOLUTIONS AND EXTERNAL RELATIONS

3.6.1 Description of Energy Solutions & External Relations Department

The Energy Solutions and External Relations (ES&ER) department is divided into the following primary functions and responsibilities:

- Energy Solutions
- Energy Efficiency and Conservation
- Communications and External Relations
- Forecasting, Market and Business Development

Costs included in the ES&ER's department O&M relate to the responsibilities described below in serving natural gas customers. Costs related to serving Alternative Energy Services (AES) customers and associated activities are not included here, and are captured in a separate company, FortisBC Alternative Energy Services Inc. (FAES).

Energy Solutions

The Energy Solutions team works closely with potential and existing industrial, commercial and residential natural gas customers (including builders, developers, large and small businesses, homeowners, municipalities, school districts and other government organizations), to find the right energy solution to meet their energy needs. The group is responsible for managing key customer accounts, developing and implementing activities to add new customers and natural gas load, identifying and assisting in developing service enhancements for existing customers, and communicating with customers regarding service options and available programs, including participation in EEC programs.

Energy Efficiency and Conservation (EEC)

This group is responsible for the development of programs designed to conserve energy, promote energy efficiency or reduce customers' energy demand. While the majority of the expenditures for these programs are accounted for in the EEC deferral accounts, the expenditures for the high carbon fuel switching program, which is managed by this group, are included in O&M. This approach is consistent with the 2012-2013 RRA Decision. Please see Appendix I for further details of all EEC programs.

Communications and External Relations

This function is comprised of two groups, Communications and External Relations. The areas of responsibility for the Communications group include the development and execution of both internal and external communications. Activities undertaken by this group include customer, employee and stakeholder communications, media activity designed to increase preferences and demand for natural gas use and safety education messaging. The External Relations group is responsible for building and fostering relationships with communities, First Nations, key government ministries, and business associations in order to engage these key stakeholders in the Company's various projects and initiatives. Such relationships are critical in supporting FEI's ability to move projects and programs forward in a timely manner for the benefit of its customers. For example, there will be considerable interaction with all levels of government, government agencies, First Nations and the public in support of development to serve the proposed Woodfibre LNG project. These relationships are essential to the Company's success as these stakeholders play a critical role in governing and/or regulating the energy industry and the external environment in which the Company operates.

Forecasting, Market and Business Development

This functional area encompasses Market Development and Business Development activities. The Market Development group is responsible for service process improvements, and the evaluation of market conditions, emerging gas technologies, and upcoming changes in codes and regulations on future natural gas use. Furthermore, the employees in the Market Development group are responsible for the forecasting of short term and long term energy demand and customer gas use, along with the development of the company's Long Term Resource Plan (LTRP). The Business Development group is responsible for identifying, developing and implementing new energy service offerings such as: renewable natural gas (RNG), or biomethane, natural gas for transportation (NGT) and Liquefied Natural Gas (LNG) or Compressed Natural Gas (CNG) for new markets.

3.6.2 Business Drivers for Energy Solutions & External Relations Department

The activities and associated resource requirements for the ES&ER department are influenced by factors that are both internal and external to the organization. These influencers include market conditions and shifts in demand, customer and stakeholder expectations, government policy, together with internal and external communication requirements. This requires being responsive to:

- market conditions, as customers, both potential and existing, and communities at large show a greater level of interest in energy conservation, energy consumption patterns and reducing their carbon footprint;
- the public's concern over safety and security; and

- the impacts of natural gas use for our customers and the Company as a result of changes to the marketplace, government policies, regulations, and standards.

Increased competitive and market risk factors have warranted the enhanced focus of the Company's ability to retain existing customers, attract new customers and maintain throughput levels in a challenging and evolving environment. The Company has been experiencing a shift in consumer demand as result of changing energy prices, public and customer perceptions of natural gas as a fossil fuel, and the competitiveness of natural gas to alternative energy sources. Although natural gas commodity prices have declined in recent years, which has improved the relative price competiveness of natural gas against electricity, this decline has been offset by increases in carbon tax along with higher capital and installation costs for natural gas equipment versus that of electricity. Furthermore, the role of natural gas in its traditional use for space and water heating continues to be challenged by changing environmental policies, energy policies and regulations..

In recent years, the ES&ER department has been diligent in developing and implementing programs and initiatives to manage competitive and market risk factors and consequently position the Company to best serve its customers. These activities have taken the form of improvements to existing processes, the development of new service offerings such as RNG, and NGT, the development of new markets for LNG and CNG, and work done to support industrial customers such as Pacific Energy Corp. (PEC).

Changes in the competitive landscape, and to regulations and polices not only increase risk but provide for the creation of new opportunities, and it is in the mutual interest of customers and the Company that these are explored and promising opportunities are developed.

3.6.3 Energy Solutions & External Relations Review

During the period 2010 to 2013, the department has continued to focus on rate mitigation efforts through initiatives designed to increase gas throughput and process changes to improve productivity levels. An increase to gas throughput is being achieved through new service offerings and the development of progressive ways to attract new customers. Productivity enhancements have been in the form of improvements to existing processes which serve to assist in the retention of existing customers in providing them with increased value. Each of these is described below.

Cost Efficiency Measures by Means of Productivity Improvements

The department has been evaluating existing processes to improve productivity levels. Efficiencies were focused on developing more streamlined solutions for existing processes and providing increased value to customers. These improvements include:

- Reduced wait times by two weeks for customers awaiting the installation of a new gas service not requiring a permit. Through a cross-functional and collaborative effort, involving the ES&ER, Operations and Customer Service departments, the Company has implemented process changes that have improved service to the benefit of customers. This continues to be an on-going initiative with the assessment of future efficiencies still in progress.
- FEI has developed and launched an on-line Home Energy Calculator (HEC). This online tool provides residential customers the ability to compare the energy costs of operating various common home appliances and the cost savings achieved by upgrading to higher energy efficient appliances. In quarter one of 2013, there were 1,423 unique visitors to this online tool[50]. The provision of such a self-help resource not only provides customers with the ability to find answers to their questions when it is convenient to them, but also reduces such questions to customer service staff, enabling efficiencies.
- FEI has developed a billed consumption database which was facilitated by the in-sourcing of the Customer Information system (CIS). The billed consumption database is used by 200+ internal users across the organization, including staff in Energy Solutions, Customer Service and EEC. It has resulted in greater efficiencies and timeliness in responding to customer enquiries related to their historical gas-use. This database allows staff to efficiently extract customer consumption history by premise to investigate individual usage patterns. In addition, an almost unlimited number of ad-hoc aggregations can be developed to investigate queries like historic consumption by premises in a postal code or to plot monthly industrial consumption by region and rate class.
- FEI has developed an online survey for industrial customers. This new online survey, launched in September 2012, provides 1,000+ industrial customers with a simplistic and less labour intensive online tool for better forecasting their future gas use and has resulted in an increased response rate. A demo of this online survey was provided at the EEC and Demand Forecast Workshop held on May 15, 2013.
- Through the integration of gas and electric activities, the Corporate Communications, and External Relations groups were able to realize productivity improvements through sharing resources across the two utilities.

Initiatives to Increase Natural Gas Throughput and Attract New Customers

While cost efficiency and productivity enhancements are critical in managing future potential cost increases, growing the customer base and increasing natural gas throughput also relieves future rate pressures for natural gas customers. As such, in recent years the department has elevated efforts in this area and some of these accomplishments are discussed below.

[50] Link to the HEC: http://www.fortisbc.com/Rebates/HomeEnergyCalculator/Pages/Home-energy-calculator.aspx

- The high carbon fuel switching program was successful in increasing customer attachment levels by 94 in 2011 and 98 in 2012[51]. Furthermore, the addition of these customers resulted in a reduction of 573 tonnes and 598 tonnes of greenhouse gas (GHG) emissions in 2011 and 2012 respectively, as customers switched from propane or oil to natural gas for their space heating needs. The program provides incentives to customers to switch from higher carbon to lower carbon-emitting fuels through the installation of high efficient ENERGY STAR® natural gas heating systems. Prior to 2012 these costs were held in a deferral account but were reclassified to O&M, from 2012 onwards, as per 2012-2013 RRA Decision. In that Decision, the BCUC determined that this program should be distinguished from the load reducing EEC programs recorded in the deferral accounts (refer to Appendix I for details of these other programs). The program adds value to both new and existing customers by reducing their fuel costs, minimizing environmental hazards associated with oil storage tanks, increasing natural gas throughput, decreasing the need to import propane and heating oil fuel from other provinces and improving overall air quality.
- Working collaboratively with existing and potential customers is critical in ensuring that natural gas forms a part of their future energy portfolio. For example, in 2012 the Energy Solutions team worked closely with the Yorkson Creek (in Langley) townhouse builder/developer to develop an energy solution that included natural gas use and achieved a desirable environmental and energy efficiency standard for homes of EnerGuide 80. This was achieved in the construction of 156 townhomes which included the installation of on-demand water heaters boasting an energy rating of 98 per cent efficiency and a 96 per cent high efficiency rating for gas furnaces. Without such collaborative and on-going education efforts, the Company would have lost the natural gas space heating and water heating load in these new homes along with such load for the 170 additional homes planned in the second phase. Furthermore, the initial results of such collaborative and informative efforts are showing promise in the most recent market capture rates for new home completions. This rate is showing initial signs of a rebound, with an increase in 2012 to 67 percent from 61 percent in 2011.
- In addition to the growth initiatives described above, in 2011 FEI introduced RNG, a new service offering intended to meet customer needs for more sustainable energy solutions. As of December 31 2012, 4,693 residential and 75 commercial customers were enrolled in the program. RNG is a renewable energy source that can be used in place of conventional natural gas for such applications as space heating, domestic hot water, electricity generation, or as a transportation fuel, and is produced using local agricultural waste. It is introduced directly into the existing natural gas distribution system. Additionally, it offers the advantage of being a carbon-neutral, renewable energy source and therefore furthers provincial climate and energy policy initiatives.

[51] The high carbon fuel switching program showed even greater success on FEVI, with 333 customers in 2011 and 459 in 2012, switching from propane or oil to natural gas for their space heating needs. This resulted in GHG reductions of 2,031 tonnes and 2,800 tonnes in 2011 and 2012 respectively.

- Another initiative developed and implemented during this period was a new natural gas service offering for NGT applications. The Company's NGT initiative benefits natural gas customers through increased year-round load on the gas distribution system and furthers the provincial goals of GHG emission reductions and its natural gas strategy for transportation. Demand for LNG and CNG intended for NGT applications is promising with 421,375 GJ forecasted for 2013, and with successive increases each year to a total of 3.259 PJ by the end of 2017. Please refer to Appendix H for more details. The business development and sales effort costs required to support NGT programs are captured in the ES&ER department's O&M expenditures. The recovery of these costs, from the NGT class of service, is captured in "Other Revenue" and is also discussed in Appendix H. Additionally, all costs associated with NGT fuelling stations are captured in a separate class of service, which is discussed in Appendix H.

These types of programs and initiatives are on-going and are developed over a period of time. Since new service offerings often follow a number of phases, including development, design, and seeking regulatory and compliance approvals, funding to support these programs must continue through their full development and implementation cycle. In order to facilitate future growth that benefits both customers and the Company, it will be necessary for FEI to continue to explore new service offerings and explore new markets for natural gas, including the development of new major industrial applications, such as the more recent development of natural gas supply for an LNG export terminal.

Department O&M Expenditure Review

Table C3-17 below shows the O&M expenditure for the ES&ER department for the period 2010 to 2013.

Table C3-17: Energy Solutions/External Relations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 8,210	$ 9,692	$ 9,905	$ 11,460	$ 11,737
Non-Labour	6,426	5,763	8,170	7,755	6,444
Total O&M	**$ 14,636**	**$ 15,456**	**$ 18,075**	**$ 19,215**	**$ 18,181**

The 2013 projected expenditure shows an increase over the 2013 approved spend for the department. The initiatives currently underway which account for the increase in spend of $1 million in 2013 are described below.

- Enhancing the high carbon fuel switching program to increase customer uptake and to accommodate customer participation rates; and

- Increasing preferences and demand for natural gas products by way of creating awareness of the benefits of natural gas use, through comprehensive customer education and outreach programs.

These undertakings are critical in laying the foundation for future growth through the upcoming five year forecasted period, and therefore the department's 2013 O&M Projection is both reasonable and appropriate given the market challenges FEI is faced with.

3.6.4 Energy Solutions & External Relations Forecast

During the next five year period, FEI will continue its efforts in customer attraction and retention, and in increasing natural gas throughput by means of undertakings led by the ES&ER department. This will entail furthering the activities and efforts expended in the recent period.

Over the proposed PBR Period FEI will continue to face the market challenges described in the business drivers section discussed above, which will in turn place upward pressure on O&M costs in the ES&ER department. Additionally, it will be critical that FEI address the following existing and emerging pressures to ensure future growth is not impeded:

- Future Changes to Codes, Regulations and Public Policies
  While recent provincial policy developments in promoting natural gas in the transportation sector are promising, natural gas continues to be challenged in its traditional market of space and water heating which together makes up greater than 80 per cent of the natural gas throughput for residential customers. For example, in the forecasted PBR Period, FEI expects further reductions in natural gas consumption for water heating, which accounts for 18 per cent of the current residential natural gas throughput, as a result of the introduction of new efficiency regulations for natural gas storage-type water heaters. As FEI's influence over these future changes to efficiency regulations is limited, it must initiate efforts to mitigate any further decline in natural gas domestic use.
- Price Competitiveness of Natural Gas
  While natural gas commodity pricing has declined in recent years, which has improved the price competitiveness of natural gas versus electricity, the decline has been offset with increases in carbon tax, and higher upfront capital cost for natural gas equipment and installation versus that of electricity equipment. Furthermore, builder/developers surveyed in the 2010 Residential New Home Survey (RNHS) suggested that the decline in natural gas in new homes in favour of electricity was attributed to the requirement to install more costly high efficient units driven by government energy policies related to GHG emission reductions. This is a disconcerting trend given that the future operating costs for the homeowner favour the use of natural gas for applications such as space and water heating.

- Traditional Natural Gas End Use Appliance Pairing is on the Decline
  The traditional pairing of natural gas space and water heating in newer homes is on the decline as reported in the 2010 RNHS. According to the survey, if customers are not installing gas furnaces, they are also much less likely to install a gas water heater. Furthermore, because a natural gas water heater requires venting, the loss of interior space to accommodate gas vents, and the additional vapour barrier penetration on the exterior of a building, favours installation of electric water heaters. Generally, the increase in direct use of natural gas for space and water heating usually displaces use of electricity, which leads to less electricity generation requirements and a lower peak load for electric power in the Province.
- Declining Use per Customer
  While FEI continues to attract new customers, there is a downward trend in average UPC for new customers, which is expected to continue over the forecast period. The average UPC has been declining due to factors such as, but not limited to, shifts in housing stock to higher density, multi-family dwellings, more energy efficient homes and appliances, together with tighter building thermal envelopes.

These market influences will place pressure on FEI's ability to attract customers and retain its customer base in the forecast period, and as such FEI must continue to augment its activities and further develop and implement new initiatives to overcome or control these threats in future periods. Furthermore, to counteract the negative impacts described above it is imperative that FEI continue to advance growth initiatives, in new markets such as NGT, CNG or LNG for remote communities, and also to advance efficient, new gas-end use technologies.

Table C3-18 below sets out the ES&ER department's 2013 base O&M along with forecasted expenditures for 2014 through to 2018. The reconciliation of the 2013 Projection to the 2013 Base for ES&ER is provided in Table C3-2.

Table C3-18: Energy Solutions/External Relations O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 12,943	$ 13,250	$ 13,535	$ 13,893	$ 14,291	$ 14,827
Non-Labour	$ 7,778	10,025	10,236	10,451	10,670	10,894
Total O&M	**$ 20,721**	**$ 23,275**	**$ 23,771**	**$ 24,343**	**$ 24,961**	**$ 25,721**

The 2014 through 2018 forecasts include the labour and benefit inflation described in Section C3.3.3. In addition, the 2014 Forecast is higher than the 2013 Base by approximately $2.6 million, as the 2014 Forecast includes programs and initiatives necessary to address the competitive and market threats identified above which will continue to remain relevant through the forecast period. These initiatives are described below.

- Customer Education, Awareness, and Outreach Programs
  This initiative is aimed at increasing preferences and demand for natural gas use through comprehensive customer education, awareness and outreach programs. These programs are critical in mitigating the market shift in demand, in particular for natural gas space heating and domestic hot water use. Growing demand for natural gas products, through educating customers of the benefits of using natural gas in managing their energy portfolio will continue to be a critical element to the Company's future success. This initiative accounts for $1 million of the increased spend in 2014.
- Advancing Natural Gas end-use Technologies and Applications
  This initiative is aimed at advancing gas end-use technologies to support the efficient use of gas applications in the residential, commercial and industrial market and ensuring they are more affordable and widely available, by working collaboratively with key stakeholders, including industry and the Canadian Gas Association (CGA). The advancement of these technologies and applications is necessary to support the future of natural gas use in residential, commercial and industry markets and align with evolving codes and standards, as FEI has limited influence in these future regulation changes. For example, through advancing the commercialization of efficient natural gas water heating equipment, this initiative will provide for a stable solution to mitigate the further decline in natural gas domestic hot water use, and will provide customers with the opportunity to reduce their energy costs. This initiative accounts for $500 thousand of the increased spend in 2014.
- Incentive Programs
  Incentive programs are needed to mitigate the threats associated with the competitiveness of natural gas, in particular the higher upfront capital costs of the equipment and the installation. These programs encourage behaviour changes to attract and retain customers. Also, new technology is generally more expensive for customers to purchase and an incentive can be successful in starting market transformation toward, for example, on-demand hot water heaters. This program will leverage the successes of the high carbon fuel switching program. This program accounts for $500 thousand of the increased expenditure in 2014.
- Community Investment in Education
  This initiative is for FEI to build and foster relations amongst educational institutions in the Province, as these establishments are becoming increasingly influential in municipal and provincial policy changes. The total increased spend is forecasted to be $200 thousand in 2014, of which 50 per cent, or $100 thousand is included here and the remainder is accounted for as a non-regulated item. This accounting treatment aligns with the 2012-2013 RRA Decision in regards to 50 per cent of community investment expenditure being allocated to the non-regulated business.

These programs and initiatives will be undertaken with existing staffing levels. No increases in staffing levels in the ES&ER department are anticipated over the PBR Period. Since the market pressures on natural gas consumption identified are not considered to be temporary and are expected to persist through the five year period, mitigating measures and programs must be sustained through this same period. For this reason, the forecasted spend for 2015 to 2018 remains at a steady level with annual inflationary increases only. FEI believes the 2014 to 2018 forecasted O&M expenditure is a reasonable and appropriate level of expenditure given the market risk mitigation efforts required in this coming period.

3.6.5 Summary of ES&ER Department

For the PBR Period, the ES&ER department will continue to face a challenging and evolving market environment, due to changes to government policies, standards, regulations and a shift in demand for natural gas. As such, the 2014 to 2018 forecasts reflect the level of expenditure required to retain and attract customers and increase natural gas throughput through this five year period. Efforts in this regard will assist FEI in managing rates for our customers.

3.7 ENERGY SUPPLY AND RESOURCE DEVELOPMENT

3.7.1 Description of Energy Supply & Resource Development Department

The Energy Supply & Resource Development (ES&RD) department provides three broad functional areas of services to the gas utilities – Gas Supply, Gas Control, and Resource Development. The purpose of each of these three functional areas and the scope of their activities are described in the following sections.

The Gas Supply group is funded from two main sources – the Core Market Administration Expense (CMAE) budget and an O&M budget. CMAE costs are a direct result of the activities performed to serve core market customers and are treated as a flow-through cost as part of gas costs recovered via gas cost recovery rates; the CMAE budget for 2014 will be submitted for Commission approval as part of the Company's regular gas cost reporting and rate setting process. The on-system transportation activities performed by the Gas Supply group are included in ES&RD O&M. The other activities of the department including management oversight, are required in support of all customers, and are included in the O&M amounts shown in the tables below.

GAS SUPPLY

The main activities for the Gas Supply team funded through the CMAE budget include completing gas commodity procurement, providing intra-day balancing supply (required primarily due to weather changes) for core customers, facilitating all gas scheduling and nominations on Company and third party pipeline transmission systems, mitigation activity based on buying and selling around excess resources and the management of relationships with financial and physical supply counterparties, storage operators and pipeline companies to the benefit of customers. Also included is the management of the movement of gas supply provided by natural gas marketers to customers under the Customer Choice program, which began in 2004.

The on-system transportation services activities within Gas Supply (funded through O&M), include management of transportation and marketing services on the Company's pipeline system, and oversight of on-system gas transportation and industrial, commercial and marketer agent services. This includes coordinating nominations and scheduling third-party shipper requests onto the system.

GAS CONTROL AND SCADA MANAGEMENT

The primary function of Gas Control is to dispatch and operate the gas transmission and distribution systems. Gas Control is a 24/7 operation that continuously monitors and operates the gas systems primarily through the SCADA (Supervisory Control and Data Acquisition) system. Gas Control manages gas flows and system linepack, responds to real-time system alarms and alerts, and functions as the coordination hub of all major pipeline and station activities, in order to meet customer energy, pressure, and gas quality requirements. In addition, Gas Control performs the daily system load forecasts, as well as short-term five-day forecasts for gas commodity purchasing.

RESOURCE DEVELOPMENT

The Resource Development group is responsible for assessing, planning and developing supply resources and major infrastructure, including pipeline, compressor, and storage projects. These strategic initiatives typically involve multiple drivers and stakeholders, with a key theme of ensuring a long-term view of resource requirements for the benefit of customers. These initiatives have included the T-South Enhanced Service, the proposed Kingsvale Oliver Reinforcement project, the coastal transmission system upgrade plan, and the pipeline reinforcement project to serve a proposed small scale LNG facility in Squamish, BC. Resource Development also monitors and participates in regional regulatory initiatives, such as proceedings involving other utilities and pipeline companies.

3.7.2 Business Drivers for ES&RD Department

Costs included in the O&M for ES&RD relate primarily to the activities completed by the Gas Control and SCADA group, and Resource Development.

GAS CONTROL AND SCADA MANAGEMENT

As discussed earlier, Gas Control monitors and operates the gas systems primarily through the SCADA system. SCADA is a real-time application that allows communication between the host system with individual field devices, where any number of measurement points, status signals and alarms may be polled and presented to Gas Control, and also permits control signals to be sent to the field to allow remote control of equipment. The SCADA system currently in use was commissioned in 2010. In line with industry practice, it is a Windows-based system and requires significant amounts of maintenance by the SCADA support staff; the system itself is facing obsolescence in a few years' time, and an upgrade is planned for 2017/2018 which will require additional SCADA support resources.

Technology advances are also increasing SCADA staff workload. Remote Terminal Unit (RTU) field devices and newer telemetry options (wireless) are decreasing in price, allowing a much larger number of field devices to be installed that feed into the SCADA host. While this increase allows Gas Control more visibility to the gas assets, it has also greatly increased workload for SCADA staff. In 2011 and 2012, over 500 new SCADA points were added, amounting to a 10 percent overall increase in those two years alone.

Gas Control also faces demographic-related succession training challenges. The potential retirement of three experienced Gas Controllers in the next five years has been identified. Due to the extensive knowledge and training period (anywhere from six to twelve months) required to fully train a qualified Gas Controller, as well as the general difficulty in filling a Gas Controller position, additional resources, in the form of temporary training positions, may be used to mitigate these risks.

RESOURCE DEVELOPMENT

The Resource Development department is primarily focused on monitoring and responding to regional developments, including assessment and development of infrastructure and supply resources in order to provide benefit to gas customers. The business drivers are connected to the following items.

- Natural Gas Supply Potential: Significant changes are occurring in the natural gas marketplace in western Canada. The major supply potential in Northeast BC has prompted the development of infrastructure initiatives that will be needed to serve new sources of demand. FEI has been, and must continue to be, pro-active and responsive to this development as it relates to optimization of existing and new infrastructure and resources. The T-South Enhanced Service is an example of FEI's response, which is attracting new supply on Spectra Energy's Westcoast system. Natural gas customers directly benefit through increased revenues, reduced pipeline tolls, and improved liquidity at BC market hubs.
- Emerging Industrial Demand: New industrial projects are being driven primarily by an interest in accessing large supplies of reliable natural gas required to serve growing demand in key Asian markets that include Japan, South Korea, and China. For example, Pacific Energy Corp. announced plans to develop a smaller scale LNG export project on the FEVI system near Squamish, and there has been increased interest from other industrial players seeking to locate sites on FEI's existing transmission system elsewhere in the Province. Resource Development has played the lead role within the gas utilities in the commercial and technical development of these types of projects.

- System Reliability: The Company will continue to evaluate opportunities within its operating region to improve infrastructure; identifying the need for such major initiatives and projects is important to determine and plan infrastructure projects required for system reliability and to meet demand growth, helping to ensure that customers in BC will continue to have access to cost effective supply over the long term.
- Regional Projects: The proposed BC LNG export projects in Northwest BC could significantly impact regional gas flows by the end of the decade. The provincial government has recently announced that four additional proponents are interested in potentially locating LNG liquefaction terminals at a new site, Grassy Point north of Prince Rupert. This brings the total of known projects considered for development in northern BC to eleven. FEI is closely monitoring these developments and potential impacts that the associated infrastructure may have on access to natural gas supplies at fair market prices.
- Standards and Regulations: Changes to standards, regulations, industry standard practices, and technology all influence the scope and activity levels required to be performed to maintain our gas transmission and distribution delivery system.
- Long Range Planning: Long range planning for the Company's gas system infrastructure is necessary given the long lead times for large infrastructure projects that typically face a range of extensive regulatory approvals, public and First Nations consultation, conceptual design, detailed engineering, and construction schedules. This work forms a critical link in the Company's ability to provide safe, reliable, and cost effective service to customers. The Company will continue to place a high priority on the completion of these activities.

In summary, FEI must be pro-active and responsive to these drivers to ensure safe, reliable, and cost-effective supply of natural gas to its customers. The Resource Development group plays a critical role in developing and executing the long-term strategy for new resources.

3.7.3 ES&RD Review

The table below shows the historical O&M expenses of the ES&RD department. The table shows that O&M was kept to 2011 levels in 2012, with 2012 actuals less than approved by about $175 thousand. The savings that occurred in 2012 relate primarily to labour cost savings due to vacancies during the year and unutilized funding that was budgeted to support feasibility studies and preliminary assessments of Resource Development initiatives during the year. The savings recorded during 2012 were not permanent in nature.

Table C3-19: Energy Supply/Resource Development O&M Review ($ thousands)[52]

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 1,869	$ 2,751	$ 3,083	$ 3,291	$ 3,197
Non-Labour	207	659	405	709	541
Total O&M	$ 2,075	$ 3,409	$ 3,488	$ 4,000	$ 3,738

As shown in Table C3-19 above, 2013 expenditures are projected to be higher than the 2013 Approved. The non-labour increases primarily relate to the radio licenses and communications costs for the increased number of SCADA telemetry sites, and for Control Room Management (CRM) initiatives to bring Gas Control operations more in-line with industry best practices as outlined in recent US CRM regulations. In addition, the labour and non-labour expenses to support Resource Development initiatives are slightly higher than anticipated based on the timing of hiring for a staff position vacant during 2012 and based on the complement of employees.

Efficiency improvements implemented over the past couple of years have resulted in the elimination of one position in the on-system transportation services function resulting in ongoing cost savings in the ES&RD O&M, although the eliminated position was partially funded through the CMAE budget. Although ES&RD has realized some productivity gains and savings, such as streamlining work processes related to the on-system transportation function, and will continue to seek opportunities for further integration and resource sharing between the gas and electric utilities, the ES&RD group faces a number of cost pressures during the coming years, as discussed in the next section.

3.7.4 ES&RD Forecast

Table C3-20 provides a high level view of the forecast O&M for the Energy Supply & Resource Development department for the PBR Period. The reconciliation of the 2013 Projection to the 2013 Base for ES&RD is provided in Table C3-2.

Table C3-20: Energy Supply & Resource Development O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,724	$ 3,908	$ 4,066	$ 4,170	$ 4,286	$ 4,443
Non-Labour	716	830	852	870	888	907
Total O&M	$ 4,440	$ 4,738	$ 4,918	$ 5,040	$ 5,175	$ 5,350

The ES&RD department, in addition to general labour and non-labour inflation as discussed in Section C3.3.3 of the Application, is forecasting the following incremental pressures.

[52] Note that the 2010 actuals are not representative of the O&M costs for the current ES&RD organizational structure as the Resource Development group was established in 2010 utilizing budgeted funds from other departments within the Company.

Additional resources in the Gas Control area for SCADA support and to provide adequate training for retirements (gas controller positions have been identified as high risk retirement positions), and incremental third party costs related to conducting feasibility studies and preliminary assessments necessary to allow the Company to pursue the development of new large infrastructure projects commencing in 2014. As discussed above, efficiency improvements implemented over the past couple of years have resulted in the elimination of one position in the on-system transportation services function resulting in ongoing O&M cost savings that partially offset these increases.

Although the Resource Development group will require additional resources to support any new infrastructure developments approved and commenced during the PBR Period, the costs related to those incremental resources would form part of the project costs and would not affect the O&M forecasts.

3.7.5 ES&RD Summary

The ES&RD 2014-2018 forecasts reflect completed and ongoing integration and productivity efforts, while recognizing the resource requirements to operate the Company's energy supply and gas control functions, and to plan and deliver resource development objectives over the next five years.

3.8 *INFORMATION TECHNOLOGY*

3.8.1 Description of Information Technology Department

Information Technology (IT) supports all of the Company's business systems and technology. This includes the following:

- Development of short and long term strategy considering business requirements as they relate to evolving technologies. This includes the responsibility of planning, forecasting and design of future infrastructure capacity requirements that will support the Company's objectives.
- Identifying, designing, operating, and maintaining the availability, security and integrity of technology and critical enterprise infrastructure including hardware and networks. A number of the technologies and systems that Information Technology is responsible for are integral to customer and employee safety, as it is relied upon to deliver critical information and communications to Operations.
- Management of the costs for the Wide Area Network (WAN), including balancing appropriate performance with cost.
- Overseeing end user technical support for all employees, contractors, applications and associated equipment.

- The management and monitoring of all telephony contracts, including cellular. Individual usages are monitored to ensure the correct contract options are applied on an individual basis to optimize value.
- The management and costs of all large printing devices for the organization. This includes ensuring printing contracts are yielding the highest value, while optimizing productivity.
- The life cycle management of technology assets. This entails optimizing life expectancy of each asset while balancing reliability and productivity. Life cycle management also involves the proper disposal of expired assets, including delivery to the appropriate recycle locations.

3.8.2 Business Drivers for the IT Department

Technology is used throughout every area of the business, and requirements of technology in each business area increase as manual systems are replaced, and processes and requirements change. This drives the need for further enhancements, integration and mobilization of systems and technology. Over the next 5 years and beyond, the demands on the IT department are expected to remain high to ensure that FEI has the support for the technology required to meet business needs and drive efficiencies.

Support costs, particularly for software, have increased 1-2 percent annually over the past 3 years. Increased reliance on technology for all areas of the business has increased complexity and demand for technical support of applications and infrastructure. The desire to deliver required information to users where and when they need it has increased the use of existing technology as well as new technologies. Information Technology must be trained on all technologies used by the organization in order to provide the necessary support. Due to the specialized nature of the technologies, on-going training is generally offered only in specific locations by the technology providers which increases costs for training and for travel and accommodations.

IT staffing levels are based on the support and sustainment needs of the Company's systems and technology. Use of internal and external resources are balanced to deliver appropriate levels of support cost effectively. External resources and outsourcing of some services provides the flexibility for the organization to evolve with changing technology and the potential resourcing changes that may result. Internal staffing levels are expected to stay flat during the PBR Period. External resourcing levels and contracts provide the flexibility to leverage efficiencies that are realized during the PBR Period.

3.8.3 IT Review

The historical O&M costs for the IT department are set out in Table C3-21 below.

Table C3-21: Historical O&M for the IT Department ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 6,252	$ 7,096	$ 7,417	$ 7,704	$ 9,660
Non-Labour	11,069	11,559	16,025	16,513	15,719
Total O&M	$ 17,320	$ 18,654	$ 23,442	$ 24,217	$ 25,379

Table C3-21 shows an increase in expenses in 2011, which was mainly due to contractual related increases, and a number of one-time credits that were received in 2010. The O&M for 2012 and forward includes the IT support costs for the insourced CIS. Both the approved and actual/projected costs were $3.1 million in 2012 and $3.4 million in 2013. The remaining $1.7 million in increased 2012 O&M was primarily due to labour inflation, disaster recovery spending, and contractual increases for software licenses and support. The incremental spending initiatives approved in the 2012-2013 RRA Decision for the IT department are included in the 2012 Actuals and 2013 Projection above.

The 2012-2013 RRA Decision requested that IT provide a more fulsome explanation of the actual IT O&M costs, relative to budgeted costs in future revenue requirements applications and, in the explanation, demonstrate that adequate budgetary controls exist to prevent the overstatement of future IT O&M costs. In this Application, FEI is proposing a PBR plan and accordingly is not providing the same level of evidence on forecast spending as it would in a cost of service application. However, in response to the above request, FEI is providing the following discussion of IT O&M costs for 2012 and 2013 relative to the budgeted or approved amounts.

The total O&M of the IT department was below the Approved amount of $24.5 million by approximately $1.1 million in 2012. The variance is composed of both the operating expenses in support of planning and development of new capital projects and initiatives including project training (called OPEX), and the regular O&M of the IT department itself.

The $1.1 million variance in 2012 is made up of the following:

- Consistent with the IT capital spending, the OPEX portion of the O&M was below the approved spending level in 2012 primarily due to the timing of the 2012-2013 RRA Decision (variance of approximately $420 thousand).
- A variance of approximately $700 thousand was due to some vacant positions that were not filled and the alignment of management between the FEU and FBC.

The 2013 Projection of $24.2 million is based on actual 2012 results and is approximately $1.2 million less than Approved. The decrease of $1.2 million from the 2013 Approved to 2013 Projection is primarily due to the following:

- $2 million decrease in labour due to positions determined not to be required in 2012, internal resources working on capital initiatives and reduction in overtime.
- $600 thousand increase in non-labour for consulting due to backfill for internal resources assigned to capital work and for backfill on overtime work.
- $200 thousand increase in non-labour for software licensing due to higher annual support and maintenance costs from vendors, and higher OPEX to support higher IT capital spending in 2013.

Information Technology continues to focus on cost control and saving initiatives in 2012 and 2013, and going forward that positively affect several areas of the Company. These savings have been embedded in current and future forecasts in the affected business areas, including Information Technology discussed above, and have helped mitigate cost pressures. Some examples of these cost control measures include the following:

- Savings have been realized by leveraging of contracts and buying power of the Fortis group of companies.
- Savings have also been realized through the prudent management and review of telephony (including cellular), printing, managed network, licensing and other contracts managed by Information Technology.
- Additional video conferencing allowed for certain meetings to take place without incurring travel costs.
- FEI continues to look for opportunities to use server virtualization in all aspects of the business and this has become the standard for any request.
- Desktop virtualization, which centralizes desktop environments to servers, continues to be used as a standard for new requests. This has extended the life of older units and reduced costs of replacement laptops and desktops due to decreased performance requirements. Desktop virtualization also reduced the support costs per user due to the ease of supporting a virtual desktop from a central location.

Efficiencies like these have accumulated to help offset the pressures of increasing wages, training and licensing costs resulting in continued stable IT operating costs in 2012 and 2013 and should continue to do so during the PBR Period.

3.8.4 IT Forecast

The reconciliation of the 2013 Projection to the 2013 Base for IT is provided in Table C3-2. As shown in Table C3-22 below, other than the labour and benefit inflation discussed in Section C3.3.3, Information Technology is not forecasting any additional labour requirements. In non-labour, IT is forecasting moderate increases primarily due to contractual obligations and incremental O&M related to IT Sustainment.

Table C3-22: IT O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 8,715	$ 8,925	$ 9,119	$ 9,363	$ 9,635	$ 10,000
Non-Labour	15,053	15,468	15,792	16,124	16,463	16,808
Total O&M	$ 23,768	$ 24,392	$ 24,911	$ 25,487	$ 26,097	$ 26,809

3.8.5 Summary of IT

IT regularly examines all of the above impacts and business requirements to find the appropriate balance of cost, risk mitigation and service. The forecasted expenditures are necessary in order to manage, maintain, and support the IT infrastructure of the Companies .

The 2013 Base O&M put forth in this Application is based on actual costs of operating IT with all systems and technologies fully operational. This forms the baseline, and the subsequent 5 year projections reflect the Company's commitment to control costs.

3.9 *ENGINEERING SERVICES AND PROJECT MANAGEMENT*

3.9.1 Description of Engineering Services and Project Management Department

The Engineering Services and Project Management organization has evolved since the 2012-13 RRA was filed, where it was referred to as Operations Engineering. Engineering Services and Project Management is now comprised of the following groups:

- Asset Management is responsible for overseeing the gas system assets, system capacity planning, and system integrity management planning to ensure safe and reliable energy delivery. This includes defining operations and maintenance activities critical to the Integrity Management Plan, operating and maintaining cathodic protection systems, and capital planning. Asset sustainment planning is an area of focus as the Company continues to seek improvements in how asset performance is predicted over near, medium and long-term planning horizons.
- The Geographic Information Systems (GIS) area is responsible for completing new mains and service construction drawings and as-built mapping. It is also responsible for developing and maintaining the GIS mapping system, maintaining gas system asset records for distribution and transmission facilities, and implementing the Gas Asset Records Project (see description in Section D4.3.3). The GIS area includes Public Underground Location Services which provides maps and sketches to those that are

planning to excavate in the vicinity of buried gas lines, as requested through BC One Call.

- Engineering provides engineering design, and drafting services to the Project Management Office, as well as technical guidance to Operations. It also provides technical oversight and management of the Gas Lab which provides gas measurement and analysis services to ensure appropriate levels of odourization in the natural gas that is delivered to customers. Engineering will continue to focus on technical compliance with codes and regulation, the maintenance of standards, competency, and engineering for gas assets.
- The Project Management Office delivers capital projects related to pipelines and above ground facilities that enhance transmission and distribution assets. Prudent and efficient delivery of pipeline and above ground gas facility projects is a key focus of the Project Management Office.

3.9.2 Business Drivers for Engineering Services and Project Management Department

Four key business drivers are influencing the scope and activity levels of the Engineering Services and Project Management Department for the PBR Period:

- The Long Term Sustainment Plan (LTSP) projections of transmission and distribution asset repair, refurbishment, and replacement that provide for the on-going safe and reliable delivery of energy to our customers;
- Changes to standards, regulations, and industry standard practices, that influence the requirements FEI must meet to maintain its position as a prudent operator of transmission and distribution natural gas delivery assets;
- Responding to customer requests to expand system utilization and throughput of gas system assets which require engineering and project management services to ensure safe reliable energy delivery; and
- The drive to improve productivity and integrate gas and electric business functions so that both utilities can continue to innovate and meet customer needs.

Projections of future asset performance can significantly impact asset management strategies and organizational response, which drives our internal efforts to continually improve in this area. The recently developed LTSP risk framework is refining our 20-year view of potential infrastructure requirements. Over the 2014-2018 planning horizon, FEI's transmission and distribution assets have been forecast to require more O&M analysis and increasing sustainment capital investment in order to proactively address increasing safety and reliability risks. As a result, Engineering and Project Management will see an increased workload in the areas of project assessment, project planning, design and drafting, and project management.

Standards, regulations, and industry standard practices are continually being developed and improved within the pipeline industry and at FEI. Engineering Services staff members monitor, influence, plan for, and respond to these developments and improvements. Over the PBR Period, Engineering Services expects that keeping up with evolving industry standard practices could result in significant cost pressures to do more with less or, alternately, may result in strategic choices to not implement some practices, which may result in FEI lagging its peer operating companies.

Potential growth opportunities to expand gas utilization and throughput of core gas system assets will benefit all natural gas customers. Projects carried out by FEI must meet rigorous engineering standards to be safe and reliable. As projects are identified, Engineering Services will evaluate the technical merits and Project Management will deliver the projects that offer value to customers and stakeholders. This will drive increased workload for Engineering Services and Project Management over the 2014-2018 timeframe.

Significant productivity improvements have already been realized and integration of the gas and electric utilities is ongoing. FEI will continue to review and simplify processes where possible, and look for opportunities to drive further integration of the gas and electric utilities for the benefit of customers.

3.9.3 Engineering Services and Project Management Review

Engineering Services and Project Management realized operational efficiencies and asset management process improvements since the 2012-2013 RRA was filed and intends to deliver further productivity improvements to minimize cost increases in the upcoming PBR Period. Key areas of focus in the recent years have been:

- Productivity Improvements;
- Asset Sustainment Planning;
- Project Delivery; and
- Technical Competency and Compliance.

Engineering Services and Project Management have successfully identified and implemented opportunities at both the organization and business process level that support integration and productivity, as well as common customer-focused objectives and strategies resulting in O&M costs savings. Examples include:

- Technology enhancements targeted for the BC One Call process have resulted in significant productivity increases. Permanent efficiencies in this area are expected to be maintained over the 2014-2018 timeframe;

- A common Director of Engineering Services for the electric and gas utilities has been appointed. Appropriate decision-making authority is being delegated to lower-level employees and is creating greater accountability for all employees;
- A common Manager, Project Management Office (PMO) for the electric and gas utilities has been appointed, delivering pipeline and above ground gas facility capital projects in a consistent, cost effective project management framework; and
- Process enhancements in the GIS area have resulted in improved customer service. Drawing production in support of distribution main expansions and alterations is faster with more efficient use of resources.

Engineering Services has maintained regulatory compliance and has adapted to new and changing regulations. Integrity Management Plan requirements mandated through CSA Z662 have been met. Long term sustainment planning has been developed and an LTSP risk framework has been produced and will be refined over time. Project Management has executed the required projects and implemented changes driven by the Oil and Gas Activities Act.

Table C3-23 below shows the historical costs for the Engineering Services and Project Management department.

Table C3-23: Engineering Services and Project Management O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 9,644	$ 10,250	$ 10,349	$ 11,266	$ 12,581
Non-Labour	3,921	4,079	3,250	4,191	$ 4,375
Total O&M	$ 13,566	$ 14,329	$ 13,599	$ 15,456	$ 16,956

The increased labour cost in 2011 is attributed to increased effort in the Company's asset management practices that help ensure asset renewal and refurbishment investments are prudent. The decrease in 2012 non-labour cost is the result of insourcing LTSP development work which was expected to be resourced by consultants. The increased O&M labour cost projected for 2013 is explained by the challenges FEI experienced in 2012 associated with attracting and hiring technical staff from the current labour markets and the plan to hire appropriate resources in 2013. The 2013 non-labour Projection reflects resources to conduct asset condition assessments and to develop more detailed asset mitigation plans.

Overall, total O&M in 2013 of $15.5 million is projected to be less than the amount approved for 2013 due to realizing the benefits of several integration and productivity improvement efforts. Three key drivers of the variance between the 2013 Projection and the 2013 Approved amounts are:

- FEI has improved productivity and decreased costs. For example, the BC One Call ticket processing automation reduced the cost of processing BC One Call tickets by $600 thousand. Productivity improvements and integration of Engineering Services and Project Management also reduced costs.
- Asset Management Long Term Sustainment Planning is maturing. Improvements in technology and processes have enabled FEI to insource the development of the LTSP resulting in productivity improvements and cost savings.
- The number of projects requiring detailed assessment at this time has been fewer than expected in the 2012-13 RRA. The LTSP re-assessed the approach to condition assessment as described in Section C4.4.3 and further described in Appendix C3, which led to a new understanding of what assets needed further assessment. Asset Management delayed project assessment until 2013 when project identification as a result of the LTSP was completed.

3.9.4 Engineering Services and Project Management Forecast

Table C3-24 sets out the department O&M forecasts. The reconciliation of the 2013 Projection to the 2013 Base for Engineering Services and Project Management is provided in Table C3-2. Engineering Services and Project Management will be challenged by the volume of work requiring engineering assessment and project management services over the forecast period. For example, there are additional labour costs forecasted over the PBR Period to meet business requirements for further development of the LTSP. Also, there are changes in labour costs driven by the labour and benefit inflation described in Section C3.3.3. In non-labour, Engineering Services and Project Management is forecasting minor cost reductions resulting from the scheduled completion of the standardized locks and security devices upgrade described in the 2012-2013 RRA.

Table C3-24: Engineering Services and Project Management O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 12,769	$ 13,407	$ 13,696	$ 14,058	$ 14,449	$ 14,993
Non-Labour	4,249	4,329	4,070	4,156	4,243	4,332
Total O&M	$ 17,018	$ 17,736	$ 17,766	$ 18,214	$ 18,692	$ 19,325

The forecast includes efficiency gains and the necessary resources that Engineering Services and Project Management need to meet LTSP assessment, planning, and project delivery pressures over the PBR Period. Anticipated pressures associated with standards, regulations and industry standard practices include the following:

- FEU will evaluate applying evolving in-line inspection (ILI) technologies to our piggable pipeline system during the 2014-2018 timeframe. An example is the potential application of crack-detection ILI technology in pipelines that may be susceptible to

Stress Corrosion Cracking. FEI predicts a requirement for increased planning, analysis, and potential operational response effort associated with applying evolving integrity assessment technologies to FEI assets.

- FEI is expecting changes to the Canadian Standards Association (CSA) Z662 standard over the 2014-2018 timeframe which will include more onerous requirements. This standard defines design and operating requirements for Canadian oil and natural gas pipeline systems. An example of a potential change is the adoption of a strain-based dent repair criteria, which would result in dents identified through ILI which previously passed Z662 defect criteria to require excavation/repair. FEI predicts increased planning, analysis, and potential operational response effort associated with changes to technical standards;
- The Canadian Energy Pipeline Association (CEPA) has indicated they will publish a recommended practice in 2014 for managing corrosion on buried steel pipelines associated with alternating current (AC) interference. AC corrosion management is an evolving field in the pipeline industry, and FEU believes it is reasonable to project that industry practice will likely trend over the PBR Period toward increased monitoring activities above and beyond today's standard practices. FEI predicts increased planning, analysis, and potential operational response effort to enable FEI to keep pace with evolving industry recommended practices with respect to integrity management;
- There is an increasing trend in the pipeline industry, in part driven by regulator expectations, for operators to fully understand and to demonstrate their utilization of both historic and current engineering data and records in operating decisions, such as maximum operating pressure calculations. To facilitate this, improved methods for data collection, data organization, and data use are being developed. Historic data collection and organization is particularly resource-intensive, an example being material properties (e.g. yield strength, tensile strength, chemical properties) dating from original pipeline construction. It is expected that pressures will be experienced over the 2014-2018 timeframe within Engineering Services and Project Management related to the effective capture and management of historic and current engineering data.
- It is expected that BC One Call ticket volumes will increase by an average of 6 percent per year over the PBR Period. These higher ticket volumes are a positive outcome and result partially from on-going advertising campaigns by FEU and other BC One Call partners, as the public have increased safety awareness to contact BC One Call prior to excavating.

FEI expects these pressures to be offset somewhat by cost reductions associated with efficiency gains from productivity and integration improvements. These efficiency gains and any associated savings are uncertain at this time.

While overall costs for Engineering Services and Project Management are forecast to continue to increase at a nominal rate, these increases are lower than they would otherwise have been absent the potential efficiency gains that may be realized over the PBR period. There is inherent uncertainty in both the pressures (e.g. unknown changes to regulatory standards) and further attainable efficiency savings. In sum, the current forecast is a reasonable forecast of the costs required to ensure customer and employee safety, maintain asset reliability and performance based on efficiencies that FEI anticipates that it will be able to realize, but has not yet attained.

3.9.5 Summary of Engineering Services and Project Management

Despite identified budget pressures over the PBR Period, Engineering Service and Project Management have mitigated incremental funding forecasts to the greatest extent possible. The forecasts reflect completed and on-going integration and productivity efforts, while also prudently recognizing increasing resource pressures needed to plan and deliver required asset programs over the next five years.

3.10 OPERATIONS SUPPORT

3.10.1 Description of Operations Support

The primary objective of the Operations Support department is to provide the organization with safe, reliable and cost-effective services. Distributed among several BC communities, including Burnaby, Kelowna, Penticton, and Surrey, Operations Support is comprised of Measurement Services, Supply Chain Services and Property Services as described in further detail below.

Measurement Services

- Meter Fleet & Meter Shop Services entails activities related to maintaining the 'health' of the meter fleet in a manner that is cost effective, reliable, and compliant with all federal regulations. It also includes measurement services offered to third parties.
- Instrument & Communication Systems (ICS) and Data Acquisition installs and maintains all electronic measurement devices, instrumentation, control and data acquisition systems throughout the Company's pipeline network. Included are activities associated with daily data validation, editing and estimation on behalf of the commercial and industrial customers that purchase natural gas through a commodity broker.
- Radio Network Services manages all aspects of the mobile radio network, SCADA data communications and data communication for the corrosion control systems deployed throughout British Columbia. Included are activities related to leasing repeater tower space for third party revenue.

Supply Chain Services

- Mechanical Services manufactures and repairs equipment and tools for both the Operations and Operations Support departments. In addition, the group provides fabrication and install services for transmission and distribution projects. Finally, the group also provides field emergency response services when additional support is required by Operations.

- Material Services manages the flow of field materials, tools and equipment used throughout the Company. This group is also required to provide field emergency response services when requested by Operations.
- Procurement Services ensures the appropriate processes are followed and agreements are in place when FEI acquires materials and services. Furthermore, Procurement provides market research, risk management, tender evaluations and vendor management.
- Fleet Services provides three core functions: vehicle planning and acquisition, vehicle maintenance coordination and support related to incident investigations and consultation on vehicle matters.

Property Services

- Property Services includes support for property taxation, negotiation of land acquisition, leases and disposal as well as related environmental reviews, maintenance of right of way (ROW) agreements and First Nations land negotiations.

Departmental Description Summary

On a combined basis, Operations Support employs between 140 and 150 employees, comprised of COPE, IBEW and M&E. Over the past five years, staffing levels have remained relatively constant, with a temporary decrease in 2012 due to employee turnover. In 2013, Operations Support filled the vacancies to the levels consistent with previous years and added additional labour resources to reflect the planned increase in capital project activities and to prepare for the Measurement Canada mandated sampling plan SS-06 which comes into effect at the beginning of 2014.

3.10.2 Business Drivers for Operations Support Department

Operations Support's O&M costs continue to be driven by codes, regulations and system reliability requirements identified both internally and in support of maintenance activities of the Operations department, Customer Service billing operations and the Company's overall capital plan. As such, any change in regulatory requirements, industry and internal standards or the capital program that significantly influences Operations Support's activity levels will have a direct impact on the funding required to provide these services.

3.10.3 Operations Support Review

For the period between 2010 and 2013, Operations Support successfully delivered on all key corporate and departmental initiatives while taking the necessary steps to increase operating productivity which has allowed for sustainable cost savings. Provided in Table C3-25 below is an O&M overview of Operations Support's costs between 2010 and 2013.

Table C3-25: Operations Support O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 8,570	$ 8,752	$ 9,379	$ 9,106	$ 10,262
Non-Labour	2,346	1,828	1,659	2,761	2,728
Total O&M	$ 10,916	$ 10,580	$ 11,038	$ 11,867	$ 12,990

Operations Support realized cost savings in 2012 of approximately $1.1 million as compared to the Approved O&M, and anticipates continuing this level of cost savings through 2013. These savings are directly attributed to lower than forecasted labour costs driven by adjustments to the sustainment capital plan which reduced activity levels, combined with the implementation of a variety of internal productivity enhancements throughout the department. Examples of the various productivity enhancements embedded within Operations Support include the following:

- Expansion of roles for existing employees in all areas of the department to enable employees to be re-directed where demand is the greatest;
- Automation of equipment within the mechanical and meter shops to reduce manual effort;
- Business process simplification through automation within Supply Chain Services, simplification of various physical processes within Materials Services to reduce cycle time and digitizing key documents within Measurement Services to reduce document management activities;
- Optimizing the use of 3rd party contractors to reduce logistics costs; and
- Continuing to pursue 3rd party revenue generation opportunities within Measurement Services, the Radio Network, ICS and Mechanical Services to offset operating costs.

Through implementation and expansion of these initiatives, Operations Support has been able to realize sustainable labour cost savings by increasing the capacity of existing employees to accept incremental work while offsetting costs by offering third-party services.

In the 2012-2013 RRA, Operations Support requested funding categorized under codes and regulations, customer and stakeholder expectations and standards and reliability. In particular, the department requested incremental funding to maintain the existing radio network repeater sites, additional portable gas detectors, pipeline emergency response equipment, electronic meter battery replacements and parts for meter sets. Furthermore, incremental funding was requested for additional AMR network fees and labour to address the introduction of Measurement Canada's mandated sampling plan SS-06 and the long term sustainment plan. For each specific non-labour request documented within the 2012-2013 RRA, the approved funding was spent as described. Additionally, in 2013, Operations Support filled vacancies to the levels consistent with previous years and added addition labour resources to reflect the increase in capital activities and to prepare for the Measurement Canada mandated sampling plan SS-06 which comes into effect at the beginning of 2014 as stated above.

Finally, additional activities are being undertaken in 2013 for on-going maintenance work related to the radio network repeater sites, repair of higher capacity commercial/industrial meters, maintenance for recently automated valves and additional freight charges associated with increased sustainment capital work.

3.10.4 Operations Support Forecast

Operations Support's efforts toward enhancing productivity allows the department to forecast stable cost increases between 2014 to 2018 with no additional labour requirements above 2013 projected levels. The reconciliation of the 2013 Projection to the 2013 Base for Operations Support is provided in Table C3-2. The forecasted O&M requirement for Operations Support is shown in Table C3-26 below.

Table C3-26: Operations Support O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 10,281	$ 10,690	$ 10,915	$ 11,199	$ 11,514	$ 11,939
Non-Labour	2,830	3,009	3,097	3,187	3,280	3,374
Total O&M	$ 13,111	$ 13,698	$ 14,013	$ 14,386	$ 14,794	$ 15,313

There are several O&M budget pressures forecasted in the O&M above, including:

1. Projected inflationary pressures: Non-labour costs are expected to increase with the largest impact relating to materials required to maintain tools and equipment. In addition, labour costs will rise in accordance with the collective agreements as described in Section C3.3.3.
2. True up of labour costs for employees added in 2013: Labour resources added part way through 2013 that are required to support the increase in sustainment capital and the change in the Measurement Canada sampling plan (SS-06) are required to be fully funded beginning in 2014.
3. Network fees associated with the continued replacement of obsolete AMR technology for large industrial customers: As the obsolete landline technology for remotely communicating meter reads is replaced with wireless technology, an incremental increase in network fees will be incurred.
4. Increased lease charges for the radio network repeater sites: Lease agreements which support FEI's radio network, SCADA communications and corrosion control systems are scheduled to be re-negotiated beginning in 2014 and an increase in lease expense is forecasted upon renewal.

It should be noted that the financial impact on Operations Support related to the capital plan is not only a function of volume and scope, but also the type of projects. For example, a project that requires significant steel fabrication using non-inventory materials such as a transmission renewal project, will have a much greater impact on the department's resources than a distribution mains and services project of similar scope that requires prefabricated polyethylene materials normally carried within FEI's inventory system. As such, Operations Support faces the risk of funding pressure should the capital program deviate significantly from the forecast in a manner which increases activities within the department.

Finally, looking forward, Operations Support plans to continue pursuing opportunities for increased productivity by exploring the potential benefits of integration and further automation of business processes while continuing to seek third party revenue opportunities.

3.10.5 Operations Support Summary

In conclusion, Operations Support has generated cost savings while delivering safe and reliable service. These savings were achieved through lower than forecast labour requirements resulting from a decrease in activities related to the capital plan and through a significant effort within the department to enhance operating productivity in a sustainable manner. Looking forward, the department plans to continue to pursue opportunities for enhanced efficiency while achieving its corporate and departmental objectives.

3.11 *FACILITIES*

3.11.1 Description of Facilities Department

The Facilities department is a centralized service group that is responsible for operating and maintaining office, shop and warehouse facilities for the FortisBC group of companies. The services provided range from building asset operation and maintenance, physical security, space planning, office furniture and equipment, mailroom and reception services. The department ensures that the Companies and their employees have a suitable work environment with safe and efficient buildings and workspaces.

3.11.2 Business Drivers for Facilities Department

Codes and regulations, asset planning and productivity are the three main drivers of activity and costs in the Facilities department.

Codes and Regulations

Facilities safeguards the Company's employees and building assets by ensuring that building and property assets remain in compliance with applicable regulatory and code requirements.

Asset Planning

Facilities manages the complete life cycle of the building and property assets from concept to disposal. In addition, the department pursues opportunities to enhance design selection to support operation and maintenance processes, budget and energy management, asset performance, capacity planning and replacement.

Facilities provides a wide range of services including:

- Cyclical maintenance – This is preventative maintenance service to keep facility assets in good condition, improving equipment utilization and reliability, and enhancing the health, safety and welfare of employees. As this maintenance is cyclical, the spending pattern associated with these tasks varies based on manufacturer recommendations, best practices and code compliance. Maintenance levels will fluctuate over multiple years, with a corresponding impact on the expenditures.
- Lease contracts – Lease contracts have stepped rate increases, renewals and expiries that affect the required operating cost for the various facilities. Lease contracts demand market rates for the specific lease area.
- Service contracts – Contract increases can be stepped with the contract term or require renegotiation.
- Administrative general – These costs vary with changes to headcount at our facilities and requirements for consulting costs to engage subject matter expertise on specific facilities-related concerns. Increases to headcount can put strains on the adequacy of the available space and can force increased use of off-site storage requirements, additional stationary, janitorial service and supplies and increases in utility requirements.

3.11.3 Facilities Review

For the period between 2010 and 2013, Facilities has successfully delivered on all key corporate and departmental initiatives while taking the necessary steps to deliver sustainable cost savings. Provided in Table C3-27 below is an O&M overview of Facilities costs between 2010 and 2013.

Table C3-27: Facilities O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 1,510	$ 1,599	$ 1,532	$ 1,634	$ 1,649
Non-Labour	5,818	5,236	8,031	7,615	7,610
Total O&M	$ 7,329	$ 6,835	$ 9,563	$ 9,249	$ 9,259

In 2012, Facilities had an increase of $2.7 million in actual spending, which was equal to the approval level. $2.4 million of this increase was to support the two new contact centre spaces brought into service as a result of the insourcing of the Customer Service function. This increase in O&M was approved in the 2012-2013 RRA Decision. The remainder of $300 thousand was driven by lease contracts, service contracts, cyclical building maintenance and labour as discussed in the 2012-2013 RRA. In 2013, Facilities is projecting to remain in line with the 2013 approved budget.

3.11.4 Facilities Forecast

The Forecast O&M for the Facilities department is provided in Table C3-28 below. The reconciliation of the 2013 Projection to the 2013 Base for Facilities is provided in Table C3-2. Facilities is forecasting no additional labour requirements between 2014 to 2018 above 2013 projected levels, with increases in labour due only to the labour and benefit inflation discussed in Section C3.3.3. However, Facilities is forecasting non-labour cost pressures beginning in 2014 driven by cyclical maintenance, lease contracts, service contracts and utility costs.

Table C3-28: Facilities O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,848	$ 1,893	$ 1,934	$ 1,986	$ 2,043	$ 2,121
Non-Labour	7,656	8,067	8,236	8,484	8,662	8,944
Total O&M	$ 9,504	$ 9,959	$ 10,170	$ 10,469	$ 10,705	$ 11,065

Provided below are examples of the cost pressures Facilities is forecasting through the PBR Period.

- Lease Contracts: FEI has a range of lease contracts that expire in late 2013 and through 2014 and is forecasting an increase in these lease costs under the new leases that will be negotiated. In addition, there are receivable leases scheduled to expire that will not be renewed, which will reduce revenue received. Offsetting these upward pressures on overall lease costs, FEI has eliminated the lease cost for the North Vancouver muster site due to the purchase of land and construction of a new muster as discussed in the 2012-2013 RRA.
- Service Contracts: The Provincial Government implemented a 17 percent increase in the minimum wage in 2012. This increase will impact numerous service contracts for minimum wage staff like janitorial, security and landscaping at the time of renewal for these services.

In conclusion, over 80 percent of the Facilities budget is for external contracts, services and material costs which are impacted by the many factors outside of FEI's control. Based on contractual commitments and market trending, FEI has made reasonable assumptions for the forecast costs; however, the Company is subject to the risk of budget pressure should the market inflation increase above the forecast at any point during the term of the PBR Period.

3.11.5 Facilities Summary

The forecast changes in costs continue to be driven by contractual inflation and required service levels for operating and maintaining building assets. Despite the uncertain nature of many of these costs over a 5 year planning horizon, FEI will continue to prudently manage these costs while working to deliver a suitable work environment with safe and efficient building and workspaces.

3.12 *ENVIRONMENT, HEALTH AND SAFETY*

3.12.1 Description of EH&S Department

The Environment, Health and Safety (EH&S) group is made up of the following areas:

- Environmental Affairs manages environmental risks associated with operational activities and the fulfilment of compliance requirements with applicable environmental regulation;
- Occupational Health and Safety manages employee safety risks as aligned with the maintenance of compliance with WorkSafeBC regulation;
- Public Safety involves the development of plans and awareness strategies relating to the education of customers, first responders, and the general public around the properties of natural gas, and about steps to be taken in emergent situations. Awareness strategies also focus on the excavation and ground disturbance process, to promote diligence in this process by anyone excavating in the proximity of utility assets. Research coordinated in the department tracks the annual effectiveness of the corporate safety planning activities;
- Emergency Preparedness involves the management of emergency management system compliance with all applicable legislation. An annual exercise program supports operational readiness;
- Business Continuity Planning involves inter-departmental planning that will result in an effective operational response and the restoration and resumption of core business functions if a business interruption occurs; and
- Corporate Security manages corporate security risks as related to the management of assets.

Management systems exist for each of the areas noted above, and programs and activities are in place throughout FEI's operations to evaluate, strengthen and continually improve these systems, while addressing public safety, compliance with regulatory requirements, and a suitable working environment for employees.

3.12.2 Business Drivers for the EH&S Department

The two main drivers of the level of work in the EH&S department are compliance with legislation and regulation as related to environmental, health and safety requirements, and the monitoring of corporate policies and operating procedures that enhance public and employee safety, and that mitigate environmental risk in our operations. EH&S continues to focus on streamlining processes, integrating management systems, and optimizing all opportunities from the integration with the Electric utility in order to increase and support productivity opportunities.

In 2012 and 2013 EH&S integrated several functions involved in the provision of gas and electric services. Through integration, and the alignment of the electric and gas EH&S groups, service quality levels were maintained; EH&S has been able to manage additional workload within existing budgets during 2012 and 2013.

3.12.2.1 Legislation and Regulation

The O&M costs incurred by the Environment, Health and Safety department are driven primarily by external legislative and regulatory requirements. Statutes such as the *Oil and Gas Activities Act;* the *Workers Compensation Act*; the BC and the Canadian *Environmental Assessment Act*; Fire Codes and Safety Standards, and other practices dictate the level of service, and the reporting and compliance activities that must be performed.

3.12.2.2 Monitoring of Corporate Governance, Policies and Procedures

FEI's corporate governance structure, in addition to well-defined policies and procedures that are continually monitored for effectiveness, continues to be important in achieving business priorities and enhancing public and employee safety. The Certificate of Recognition (COR) audit program and certification process that is recognized by WorkSafeBC, involving both internal and external audit protocols, continues to validate the Company's safety management system. Two of the current Balanced Scorecard measures, Recordable Injuries and Recordable Vehicle Incidents, measure workplace health and safety. The Balanced Scorecard is discussed further in Section A5.1.

The Company maintains an Environmental Management System (EMS) that is aligned with the ISO 14001 Standard, and environmental risk associated with the construction, operation, maintenance, and emergency preparedness around Company facilities are addressed in FEI policies, standards and procedures, such that compliance with regulations is enforced.

FEI places a high priority on safe work planning and practice, and on minimizing operational impacts of works conducted in our natural environment throughout the Province.

EH&S training and competency programs at FEI continue to be enhanced and updated in accordance with new regulatory requirements as required. Regarding environmental training, at page 67 the 2012-2013 RRA Decision (Appendix A, p. 4, directive 22), the Commission directed FEI as follows:

> *"FEI is directed for future revenue requirements to determine potential alternatives for the delivery of the environmental training program and potentially integrate it with other training opportunities."*

Pursuant to this directive, all environmental training has been integrated into the existing training curriculum for the Company, consistent with the delivery of other operational training. No other alternatives were explored since this was the most cost effective method of delivery as it utilizes already existing resources, and has the added advantage of providing more control in the management of the program.

3.12.3 EH&S Review

Table C3-29 below sets out the historical O&M for EH&S. The table shows that the EH&S total O&M expenses have remained stable over the four year period. Additional labour costs in 2011 and 2012 reflect the addition of resources to support public safety awareness and the emergency management program. This is balanced by a decrease in non-labour expenses in those years due to the award of the 'Certificate of Recognition'[53] (COR) rebate in each year, and the shift of various EH&S competency related training development (e-learning courses) to the Training Department in 2012. The benefit of the COR is expected to be realized in 2013 and onward, although the amount will vary by year, and per the program guidelines will decrease or increase as company WorkSafeBC premiums decrease or increase.

Table C3-29: EH&S O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 984	$ 1,327	$ 1,344	$ 1,366	$ 1,574
Non-Labour	1,443	1,118	1,137	1,314	1,425
Total O&M	$ 2,427	$ 2,445	$ 2,481	$ 2,681	$ 2,999

Incremental funding requests approved in the 2012-2013 RRA were applied to each area of focus, in order to continually enhance program elements (such as improved telephony and tracking systems), to evaluate and ensure that any potential synergies that corporate integration has enabled are implemented, and to identify any external regulatory compliance requirements that require system, process or planning procedural changes.

The 2013 Projection shows a decrease from 2013 Approved due to EH&S gas and electric utilities integration and alignment efforts as described further below, but an increase in non-labour compared to 2012 Actual due to a delay in commencing some environmental-related consulting work that was expected to commence in 2012.

[53] Certificate of Recognition is a financial reward (a refund of a percentage of premiums paid) from Worksafe BC for those companies that satisfy a comprehensive third party audit and certification process.

EH&S has managed its costs to only an inflationary increase through a focus on productivity. Many processes, programs, and operating standards in the gas and electric utilities have been aligned, and further program alignment will occur wherever appropriate. For example, the WHMIS (Workplace Hazardous Materials Information System) was aligned, the incident investigation process was synchronized, and the Emergency Planning program planning was aligned as was the selection of external consultants wherever operationally feasible, so as to take advantage of any economies of scale that exist. Certain roles were also aligned between the gas and electric divisions. In aligning the professional expertise of existing gas and electric division EH&S employees across all utility project works and especially during emergency response, the Company is enhancing internal cross-divisional operational support capabilities without increasing the current number of employees in the department. Ongoing reviews of opportunities for further process alignment will continue; however, varying regulatory and utility operational requirements may limit alignment in all program areas.

EH&S tracks external regulatory developments on an ongoing basis and is continuing with associated industry consultation. This work has been managed at current department staffing levels despite ongoing changes to regulations. Additional regulatory requirements have occurred in areas such as:

- General hazard mitigation requirements with respect to confined space, cranes and hoists, avalanche preparedness and working alone;
- Vegetation management activities around fish-bearing streams to protect and conserve riparian habitat, and to manage any invasive species;
- Greenhouse gas monitoring, verification, and reporting;
- Riparian Areas Regulation for new utility corridor works in designated parts of the Province requiring extra studies by Qualified Environmental Professionals and other related provincial regulations; and
- Security monitoring and control.

3.12.4 EH&S Forecast

Table C3-30 sets out the 2013 Base and the high level 2014-2018 operating and maintenance forecasts for EH&S. The reconciliation of the 2013 Projection to the 2013 Base for EH&S is provided in Table C3-2. Overall, EH&S is not forecasting incremental increases in the 2014 through 2018 period beyond inflation.

Table C3-30: EH&S O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,546	$ 1,583	$ 1,617	$ 1,661	$ 1,709	$ 1,774
Non-Labour	1,326	1,351	1,380	1,409	1,438	1,468
Total O&M	$ 2,872	$ 2,934	$ 2,997	$ 3,069	$ 3,147	$ 3,242

As discussed in the 2012-2013 RRA, in the last five years there have been a variety of changes to regulatory requirements, and increasing public expectations and awareness, with respect to safety and the environment. These changes may lead to additional measurement or reporting activities in future years. The impact of these additional activities on O&M requirements is difficult to quantify at this time.

The following discussion identifies certain regulatory areas that FEI is currently monitoring.

Species at Risk Regulation

The *Species at Risk Act* (SARA) is a federal act that is intended to prevent wildlife species in Canada from being extirpated or becoming extinct, to provide for the recovery of wildlife species that are extirpated, that are endangered or that are threatened as a result of any human activity and to manage species that may be of special concern, in order to prevent them from becoming endangered or threatened. FEI is currently evaluating the uncertainty that exists as related to how regulatory authorities are managing and interpreting SARA conditions and the legal challenges surrounding the implementation of future regulations, which may have impacts on the execution (timing and environmental monitoring requirement changes) of utility operational works. As additional species continue to be added to the current listing, additional critical habitat considerations, including recovery strategy analyses, consulting fees, and additional permitting may need to be considered for project related or routine operations and maintenance works that currently do not attract these costs; furthermore, these costs may be unexpected if the species found on a job site fall into this category, triggering delays that may translate into additional costs. Resolution of these issues is very slow, and therefore, planning and budget forecasting is challenging with respect to any additional operational requirements that may emerge.

Greenhouse Gas Management

FEI is required to report on Greenhouse gas emissions in accordance with the requirements of the *Greenhouse Gas Reduction (Cap and Trade) Act*. The regulation sets out the requirements for the reporting of greenhouse gas emissions by FEI, as per the requirement for B.C. facilities emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year; this requirement began on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. As the regulation evolves, additional requirements are being reviewed with Regulators; and may result in additional measurement, reporting, and verification costs over time.

FEI is currently monitoring regulations under SARA and greenhouse gas management requirements. Changes to these and other regulations and legislation can occur at any time. As such, FEI's forecasts remain uncertain. The forecasts provided in the table above assume that any incremental new requirements will be absorbed through productivity offsets. For example, program alignment will be considered to maximize efficiency in the use of external contractor resources and in the purchase of emergency management supplies.

3.12.5 Summary of EH&S Department

EH&S historical spending has been stable and FEI's high-level forecast is for incremental increases in the 2014-2018 period to cover inflation of labour and benefits for existing employees, and inflationary non-labour increases. EH&S expects that there may be additional regulatory requirements, the cost of which will need to be absorbed through productivity offsets.

3.13 *FINANCE AND REGULATORY SERVICES*

3.13.1 Description of Finance & Regulatory Department

The Finance and Regulatory department is responsible for providing a range of financial and regulatory services to various departments throughout the Company.

Finance

The Finance department is responsible for budgeting and forecasting, financial reporting, treasury, taxation, accounting and financial systems. This includes preparing overall financial plans, operating budgets and forecasts; preparing financial statements in conformance with reporting requirements; designing and maintaining the internal controls and policies; reporting of taxes and filing of tax returns; and managing the general ledger.

Despite the ever increasing demands and financial complexity discussed further under Business Drivers, the staffing level for the Finance department has remained stable in recent years at approximately 50 employees, and is forecast to remain relatively consistent over the forecast period.

Regulatory

The Regulatory department is responsible for the provision of regulatory services, including preparing all revenue requirement, cost of capital and rate design applications, applications for CPCNs, energy supply applications and providing interpretation, education and communication of regulatory requirements and policies to departments throughout the Company.

The staffing level for the Regulatory department has declined from 18 to 16 employees since 2010, with some other temporary fluctuations due to vacancies. FEI is not forecasting a change to the staffing level in the Regulatory department over the forecast period, although, due to the denial of the amalgamation of the gas utilities, it will be filling some temporary vacancies in 2013.

3.13.2 Business Drivers for Finance & Regulatory Department

Finance

The Finance department's resource requirements are influenced by changes in financial and accounting standards and reporting requirements, compliance requirements and regulatory decisions, changes in taxation legislation and ongoing audits, treasury activities and capital expenditures, as well the requirement to respond to the accounting needs of the various departments within the Company.

In recent years, the Finance department has successfully transitioned reporting standards and supporting processes from Canadian GAAP (CGAAP) to the current US GAAP and continues to administer established financial policies and processes. Similar to International Financial Reporting Standards, US GAAP guidance continues to evolve and become more complex. Accordingly, the Finance department is responsible for the ongoing assessment and implementation of accounting guidance and standards. These accounting policy changes may result in adjustments to financial statement presentation and note disclosure, as well as changes to the financial reporting and accounting processes. Certain accounting policy changes may not result in a financial statement or regulatory impact; however, they still require the Finance department to perform extensive research into the facts and circumstances and the preparation of position papers for external auditors. Similarly, income tax legislation and regulations are also increasingly complex. This complex environment requires vigilance to ensure that changes affecting the Company are identified and applied appropriately.

Additional challenges for the Finance department include incremental requirements driven by the increased number and complexity of regulatory filings. Further, the Company's forecasted capital expenditures over the next five years will require the Finance department to manage debt financing, either through operating credit facilities or debt offerings, and the managing of budgets and accounting for and reporting of capital expenditures. A priority is being responsive to the needs of other departments, ensuring that accurate and timely accounting and financial information is provided to departments to help manage the business.

These needs have changed and will continue to change over time. To meet these changing and increasing requirements, the Finance department assesses its resource requirements regularly to ensure effective deployment of resources available. In 2012, this contributed to one-time labour savings realized as vacant positions were filled only after reviewing the need for the positions and evaluating how best to staff the positions.

Regulatory

The resources required by the Regulatory department are driven by the regulatory environment, particularly the number and complexity of rate setting and project approval filings with the Commission. In recent years and since coming out of the last PBR, the complexity of FEI's applications, regulatory processes and compliance requirements has increased. Regulatory processes are typically attracting more interveners, taking longer, and costing more than in previous years. The increased interest, and the associated time and cost requirements continue to put pressure on the Company's regulatory and other resources. Although the Company is challenged to maintain the current level of regulatory process and activity, it is not planning to increase personnel beyond the discussions included in the Finance & Regulatory Review section below.

3.13.3 Finance & Regulatory Review

From 2010 to 2012, the Finance and Regulatory department has managed its costs at a level below inflation as shown in Table C3-31 below.

Table C3-31: Finance and Regulatory O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 6,212	$ 6,550	$ 6,007	$ 6,783	$ 7,695
Non-Labour	5,965	5,514	6,142	6,496	6,490
Total O&M	$ 12,177	$ 12,064	$ 12,149	$ 13,279	$ 14,184

During the period 2010 - 2012, the Finance and Regulatory department has managed to meet its different and changing business requirements and contain costs, with a continued focus on productivity. The department has managed an increasing number of major applications (average of 63 per year for the five years from 2005 to 2009 as compared to 72 in the three years from 2010 through 2012). In addition, the number of Information Requests responded to has increased (average of 2,500 for the five years from 2005 to 2009 as compared to 4,200 in the three years from 2010 through 2012). At the same time, during this most recent three year time period, the regulatory department has decreased its staffing level, demonstrating the productivity focus of the department.

When compared to the O&M costs of the department and number of employees, which has either held constant or declined, the direction to continue to do more with the same number of employees is evident. Labour costs declined in 2012 from higher levels in 2010 and 2011 as executive and associated support positions were consolidated. Additionally, staff turnover caused in part by employees progressing in their career development within the Company have contributed to vacancies. Difficulties in filling these vacancies on a timely basis have contributed to lower spending levels in the past.

In 2013, higher labour expenditures are expected due to inflation for labour and benefits, and the filling of existing vacant positions which were put on hold in part pending a decision on amalgamation of the gas utilities. Now that the utilities will require separate revenue requirement, rate design and cost of capital applications, separate financial reporting and implementation of various service offerings in the separate utilities, the savings realized in the past year are no longer considered permanent.

The increase in non-labour is due in part to inflation on financial services provided by FHI through the Corporate Services fee and also for additional taxation services being provided in 2013. Other contributors to the increase in 2013 are related to external audit fees, taxation consulting fees, SAP and systems support and miscellaneous support costs.

The 2013 Projection is still approximately $900 thousand lower than the 2013 Approved, capturing permanently the bulk of the efficiencies realized to date and reflective of a continuation of the productivity focus. The 2013 Projection is carried forward into the 2013 Base that is used for future customer setting.

3.13.4 Finance & Regulatory Forecast

Table C3-32 provides a high level view of the forecast O&M for the Finance and Regulatory department from 2013 to 2018. The reconciliation of the 2013 Projection to the 2013 Base for Finance is provided in Table C3-2.

Table C3-32: Finance and Regulatory O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 7,657	$ 7,839	$ 8,007	$ 8,218	$ 8,453	$ 8,769
Non-Labour	7,422	7,563	7,722	7,884	8,049	8,218
Total O&M	$ 15,079	$ 15,401	$ 15,728	$ 16,101	$ 16,502	$ 16,987

Other than labour and benefit inflation as discussed in Section C3.3.3 of the Application and general non-labour inflation, the Finance and Regulatory department is not forecasting any major pressures but will be challenged to continue to meet upcoming requirements with existing resources. Regulatory requirements are expected to remain high, particularly with the number of utilities being managed and the anticipated number of filings that are anticipated for these utilities. Additionally, Finance service requirements are expected to continue to change and increase. The Finance & Regulatory department will try to address this challenge by seeking out further productivity gains and savings by reviewing and streamlining existing work processes and capitalizing on integration and resource sharing opportunities between the gas and electric departments.

3.13.5 Finance & Regulatory Summary

For the Forecast period, the Finance and Regulatory department is not projecting incremental funding beyond that required for labour and general inflation. As in the past, the department will maintain its focus on productivity while continuing to deliver on its service requirements.

3.14 *HUMAN RESOURCES*

3.14.1 Human Resources Departmental Overview

The overall goal of Human Resources (HR) is to ensure that the Company's workforce, now and into the future, has the level of skill and capacity to achieve its business goals and objectives. The Human Resources department performs and provides different services to support management of the workforce to ensure effective and efficient alignment with business plans.

HR has 58 employees, a reduction of approximately 17 percent from previous years. The following sections provide an overview of the activities and responsibilities within each of the four functional areas in the Human Resources department.

3.14.1.1 Corporate Human Resources

Corporate HR ensures that the HR direction and programs that affect employees are aligned with departmental and corporate objectives. Areas of responsibility of Corporate HR include HR business planning, and compliance with regulatory, and governance reporting.

3.14.1.2 Employee Services

Employee Services oversees the design and delivery of the Total Rewards framework to attract, retain and motivate employees, and ensures recruiting and selection processes meet business needs and operational requirements. Areas of responsibility include compensation, payroll and time administration, benefits administration, pension administration, recruiting, HR Information Systems and master data, and HR metrics, surveys and reporting.

3.14.1.3 Employee Relations

Employee Relations provides direction and delivery of labour relations and advisory services to maintain and foster productive employee/employment relationships. Areas of responsibility include HR advisory services, disability and attendance management and labour relations, including, but not limited to, collective agreement interpretation, administration and collective bargaining.

3.14.1.4 Employee Development

Employee Development partners with the business to design and deliver employee training and development programs. Areas of responsibility include development and delivery of trades training and in-house apprenticeship programs, learning content management, management training and leadership development, e-learning, competency management and administration and training records.

The structure of the Human Resources department allows the Company to efficiently respond to evolving workforce needs. FEI will continue to place a high priority on all Human Resources activities to ensure that it is able to meet its objectives of retaining, attracting and motivating employees to meet customer needs and achieve desired business results.

3.14.2 Business Drivers for Human Resources Department

The three main HR business drivers are codes and regulations for employee competency and training, an aging workforce and a focus on productivity.

3.14.2.1 Codes and Regulations

HR works with the business units to prepare training that establishes employee competence in meeting the requirements of codes and regulations that influence gas operations. To meet the requirements set out in CSA Z662 Annex "A" and Annex "N", FEI has implemented a Competency Management Program where required competencies are identified, training is developed/secured and delivered, assessments are completed and training activity documented. The governing authorities that oversee and set codes and regulations for gas operations include the Canadian Standards Association, Health Canada, Transport Canada and the WCB.

3.14.2.2 Aging Workforce

In the labour market today, there is a mismatch between the skills employers seek and those available.[54] Experienced workers are retiring and as a result organizations, including FEI, are concentrating effort in workforce planning, attracting and retaining critical-skill employees and developing internal talent.

The influences of an aging workforce will persist for the near future. On their 2013 budget website[55], the Government of Canada's description of labour market needs includes the following:

1. "…between 2012 and 2020, the construction sector will need 319,000 new workers."
2. "…95,000 Engineers will retire by 2020 and Canada will face a skills shortage…"
3. the Petroleum producers "sector will need between 50,000 and 130,000 by 2020."
4. the Electric energy "sector will have to recruit over 45,000 new workers-almost 48 per cent of the current workforce by 2016."

A summary of the challenges of the aging workforce and FEI's plan to prudently manage demographic transitions is provided in Section C3.3.6.

3.14.2.3 Productivity

The prospect of increased labour demand and decreased access to skilled labour has organizations, including FEI, focused on increasing productivity with available resources. To continue to increase productivity, FEI is focused on streamlining processes, leveraging technology and optimizing opportunities from integration with the Electric utility.

In mid-2012, HR gas and electric HR services were integrated. Through integration, HR processes were reviewed, roles were redesigned and automation technology was implemented. While maintaining or improving service quality levels, HR has been able to manage additional

[54] Anon. The Talent Management and Rewards Imperative for 2012, Leading Through Uncertain Times. The 2011/2012 Talent Management and Rewards Study, North America,Towers Watson, 2012

[55] http://www.budget.gc.ca/2013/doc/plan/chap3-1-eng.html, taken March 24th, 2013

workload within existing budgets during the 2012-2013 test period. Section A3 provides an overview of the HR productivity achievements during this period.

3.14.3 Human Resources Review

In 2012 and 2013, Human Resources implemented the approved 2012-2013 RRA requests. To satisfy requirements set out in CSA Z662 Annex N, processes for on-going competency reporting and data entry were implemented. To accommodate increased levels of training related to an aging demographic, FEI implemented a blended learning delivery model consisting of instructor-led learning, computer based learning (e-learning) and informal learning (i.e. mentoring, peer training, on the job training, coaching). Technical support services were provided to help employees when accessing courses online. To offset the need for increased HR services due to the insourcing of the customer care function, Employee Self-Serve and Manager Self-Serve (ESS/MSS) was implemented. ESS/MSS automates time entry, salary administration and compensation management for the M&E and Contact Centre employee groups through the use of self-serve technology in SAP. These employee groups can now access their pay information online, reducing payroll administration services required by HR. To support this new initiative an ESS/MSS IT HR support resource was hired.

Table C3-33 sets out the 2010 through 2013 O&M for Human Resources. The table shows a decrease in non-labour costs in 2011 due to the insourcing of employee development activities previously completed by consultants. In 2012 non-labour costs increase due to requests approved in the 2012-2013 RRA. Projected costs in 2013 are aligned with the amount approved, although there has been a shift of resources from labour line to non-labour, as discussed below.

Table C3-33: Human Resources O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 6,240	$ 6,276	$ 6,254	$ 5,541	$ 6,686
Non-Labour	2,583	1,894	2,356	2,917	1,825
Total O&M	$ 8,823	$ 8,170	$ 8,610	$ 8,458	$ 8,511

In late 2011, HR explored integrating gas and electric HR services looking for efficiency opportunities. This resulted in the insourcing of leadership development training delivery, competency management and related training activities. In 2012, employee development, talent sourcing, labour relations, compensation administration, pension and benefits administration and corporate HR functions were integrated between gas and electric utilities. During the integration, roles were redesigned and repurposed for integrated program offerings to reflect an evolving organization. Vacancies generated by attrition and retirements were not filled with a focus to create efficiencies while maintaining or improving service levels.

The integration of HR services supports the alignment of the FortisBC gas and electric utilities.

Integration within employee programs began with common M&E compensation elements including job banding, salary scales, short-term incentive and performance management programs. Integrated employee programs support the movement of staff throughout the Company and enable operational flexibility through mobility of the workforce.

In 2012, Customer Service transferred four Knowledge and Learning Facilitators to HR at a cost $465 thousand. As a result of efficiency savings achieved through integration, HR was able to absorb this cost without a budget transfer from Customer Service.

Alignment of employee programs and the use of technology achieved efficiencies in administration. These efficiencies result in projected labour cost savings of $1.4 million in 2013 Projection as compared to 2013 Approved, which is offset by an increase in non-labour costs. The increase in non -labour is a result of cross charges from electric to gas where electric employees support programs across utility lines, contract services for training development and delivery and employer branding initiatives which support recruitment efforts. Additional non-labour costs are also assigned to leadership development, business acumen training and documentation for knowledge transfer in support of workforce planning activities.

3.14.4 Human Resources Forecast

Table C3-34 sets out the 2013 Base and the high level 2014-2018 operating and maintenance forecasts for Human Resources. The reconciliation of the 2013 Projection to the 2013 Base for HR is provided in Table C3-2. Overall, HR is not forecasting any material increases in non-labour or labour costs. Labour cost increases are as a result of labour and benefit inflation as described in Section C3.3.3; no additional employee resources are forecasted. Similarly, non-labour cost increases are limited to incremental non-labour inflation.

Table C3-34: Human Resources O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 6,254	$ 6,405	$ 6,545	$ 6,720	$ 6,915	$ 7,178
Non-Labour	2,938	2,994	3,057	3,121	3,187	3,253
Total O&M	$ 9,192	$ 9,399	$ 9,601	$ 9,841	$ 10,102	$ 10,431

The need to sustain a culture of productivity improvement continues to influence HR programs. HR will continue to deliver productivity enhancing programs like the competency assessment and e-learning model that contributed to the $750 thousand in savings for Distribution field based training.

HR is supporting the workforce planning needs of both electric and gas utilities. Between 2013 and 2018, 909 employees or approximately 39 percent of the total FortisBC employee population will be eligible to retire with reduced and unreduced pensions. The need to focus on workforce planning, attraction and retention, and training and development services will continue throughout the 2014-2018 PBR Period. In response to an aging workforce, HR will continue to focus on forecasting retirement rates, targeting recruitment efforts, developing internal leadership capability, and building specific technical knowledge.

3.14.5 Human Resources Summary

HR is not forecasting incremental funding beyond inflationary increases during the PBR Period. Efficiencies in HR service delivery and in the leveraging of technology have been used to offset the costs of increased activities in workforce planning and targeted recruitment and development of staff as part of the Company's execution on its five year workforce plan. HR will continue to explore future productivity opportunities.

3.15 *GOVERNANCE*

3.15.1 Description of Governance Department

The governance department consists of three functions provided by FHI to FEI. The functions are legal services, insurance and risk management, and internal audit.

Legal Services

The legal department provides all primary legal services and counsel to departments in both the gas and electric utilities on various issues including operation, customer service, energy supply and resource development, information technology, engineering services and project management, facilities, finance and regulatory, environmental and health and safety, employment, securities and corporation, and intellectual property. In addition, the legal department engages and manages external legal resources in matters that require specific or specialized expertise and skills.

The legal department maintains a stable staffing level, with little variation in the number of employees. It is comprised of seven lawyers, one corporate secretary, two paralegals and one administrative support staff. The legal department has developed in-house expertise in environmental and regulatory support over the past few years. Bringing these functions in-house provides benefits to FEI; it results in lower overall costs compared to relying solely on an external legal resource; it provides an increase in embedded corporate knowledge; it increases efficiency in the delivery of legal services. The effects of these incremental costs have been included in the 2013 Projection. The forecasts for the legal department are reduced by the expected charges to the Electric division.

Insurance and Risk Management

Insurance and risk management services is responsible for ensuring compliance with appropriate governance requirements on risk management and for arranging insurance coverage based on potential risk, and ensuring an appropriate and prudent insurance program.

The insurance and risk management department is responsible for the renewal of all third party insurance and the cost of the premiums paid for those policies.

Insurance and risk management is a stable department which has been comprised of two employees for many years.

Internal Audit

Internal audit is responsible for planning and conducting audits and operational reviews of all areas of the gas and electric utilities. This department monitors and evaluates the effectiveness and efficiency of internal controls. The external auditors continue to rely heavily on the work of this department, saving them time and duplication in their own testing. Reducing the time required of external audit serves to reduce their year-over-year increase in audit fees.

Internal audit is a stable department which is comprised of four employees. The forecast for internal audit is reduced by the expected net charges to the Electric division.

3.15.2 Business Drivers for the Governance Department

Other than insurance premiums, the three departments provide services across the organization and the resource requirements are influenced by the specific needs of the other departments of FEI. Other than outside legal costs and insurance premiums, the majority of the costs for the three departments are comprised of internal labour related costs.

3.15.3 Governance Review

The table below sets out the historical O&M for each Governance area.

Table C3-35: Governance O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Legal Services	$ 2,039	$ 2,280	$ 1,917	$ 2,282	$ 2,282
Insurance	4,410	4,631	4,397	4,617	4,617
Risk Manageme	334	332	357	281	281
Internal Audit	586	653	695	755	755
Total O&M	$ 7,368	$ 7,895	$ 7,366	$ 7,935	$ 7,935

The costs in each of these areas have been generally stable over the past few years. The decline in costs in 2012 is due to reliance on external legal services being lower in 2012 compared to the Approved. However, external legal costs are expected to return to pre-2012 levels in 2013 due to the increased demands of various departments of FEI. The insurance premiums included here are the amounts approved each year and any variance from forecast is subject to deferral and refunded to or recovered from customers in later years. Third-party premiums are not within the control of FEI and are influenced by FEI's insured losses, coverage levels and investment income.

3.15.4 Governance Forecast

The table below shows the O&M forecast for the Governance department for the PBR Period. The reconciliation of the 2013 Projection to the 2013 Base for the Governance department is provided in Table C3-2.

Table C3-36: Governance O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Legal Services	$ 2,282	$ 2,325	$ 2,374	$ 2,424	$ 2,475	$ 2,527
Insurance	4,710	4,990	5,290	5,610	5,945	6,300
Risk Management	281	287	293	299	305	312
Internal Audit	755	769	785	802	819	836
Total O&M	$ 8,028	$ 8,371	$ 8,742	$ 9,135	$ 9,544	$ 9,974

General labour and benefit inflation will be a cost pressure as discussed in Section C3.3.3. Other than this and general non-labour inflation, the Governance department is not forecasting any major incremental increases but will be challenged to continue to meet upcoming requirements with existing resources. While there are no currently quantifiable pressures, the Governance department has noticed a trend of increasing legal and compliance obligations.

The insurance expense is forecast to escalate at a rate more than inflation between 2013 and 2018. The insurance expense is volatile due to a number of factors including the general market conditions for insurance companies as described in Section D4.3.2 of this Application. The impact of large losses over the past number of years has insurance companies becoming more sensitive to catastrophic events such as earthquakes and hurricanes. As a result, the forecast for insurance premiums is higher than an inflationary increase.

As in the past, each of the areas within Governance will be challenged to meet future requirements with existing resources. Service requirements in the future are expected to continue to increase and become more complex. Each of the areas will seek to address these challenges by continuing to identify additional productivity gains and savings by reviewing and streamlining existing work processes, and by capitalizing on integration and resource sharing opportunities. This will enhance the scalability of each of the departments enabling them to meet changing and increasing demands while containing costs.

3.15.5 Summary of Governance O&M

For the PBR Period, the Governance department is not projecting incremental funding required beyond that of labour and general inflation, other than insurance premiums which are subject to deferral treatment. As in the past, the Governance department will maintain its focus on productivity while continuing to deliver on its service requirements.

3.16 *CORPORATE*

3.16.1 Description of Corporate Department

The Corporate department contains a number of items that do not reside in any particular department. These are corporate-wide costs and recoveries, consisting primarily of:

- FEI's portion of the Corporate Services fee that has not been allocated to the other departments (see Table D3-8));
- FEI's portion of the Board of Directors costs;
- the retiree portion of pension and other post-employment benefits for 2010 to 2013 (starting in 2014 these costs are included in departmental and capital benefit loadings as discussed in Section D3.1);
- FEI's portion of the cost of the President & CEO's office;
- recoveries from non-regulated businesses;
- recoveries from FAES as described in Section D3.6; and
- shared service recoveries from FEVI, FEW, Fort Nelson, and CMAE.

3.16.2 Business Drivers for the Corporate Department

The Corporate department's main cost drivers are governed by the Shared Services Agreements and Corporate Services Agreements. These agreements benefit the organizations involved as they enable the FortisBC group of companies to harvest the benefits of economies of scale by having a single corporate management and support structure while avoiding duplication of work, allowing customers to benefit from the efficiencies realized.

3.16.3 Corporate Review

The following table presents the historical O&M for the Corporate department. The labour component in the table below is mainly the retiree portion of pension and OPEB costs and one executive assistant, as well as any one–time, corporate, labour-related costs as further described below. The non-labour components consists of the shared and corporate services fees, the cross-charges between affiliates including the allocation of the President and CEO, Board of Directors costs, and any one time non-labour corporate costs as described further below.

Table C3-37: Corporate O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 6,224	$ 3,693	$ 6,839	$ 5,968	$ 6,013
Non-Labour	(4,065)	(2,254)	(4,924)	(6,326)	(5,784)
Total O&M	$ 2,158	$ 1,439	$ 1,915	$ (358)	$ 230

The costs in the Corporate department have generally shown a declining trend. Each of the years 2010 through 2012 include some one-time costs related to the integration of the natural gas and electric utilities. No such costs are forecast to occur in 2013. The 2013 Projection is below the 2013 Approved in non-labour mainly due to higher than forecast recoveries for shared services.

3.16.4 Corporate Forecast

Table C3-38 provides a high level view of the forecast O&M for the Corporate department from 2013 to 2018. The reconciliation of the 2013 Projection to the 2013 Base for the Corporate department is provided in Table C3-2.

Table C3-38: Corporate O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 131	$ 135	$ 138	$ 143	$ 148	$ 155
Non-Labour	$ (6,292)	(6,520)	(6,616)	(6,743)	(6,874)	$ (7,069)
Total O&M	$ (6,161)	$ (6,385)	$ (6,478)	$ (6,600)	$ (6,726)	$ (6,914)

In the PBR Period, other than the general labour and benefit inflation changes described in Section C3.3.3 and general non-labour inflation, net recoveries are forecast to increase due to higher shared services cost recoveries, partially offset by higher fees from the Corporate Services fee.

3.16.5 Corporate Department Summary

For the PBR Period, the Corporate department is not projecting incremental funding requirements beyond that of general inflation. The forecasts include the Shared and Corporate Services allocations discussed in Section D3.6 of this Application.

3.17 *SUMMARY*

FEI's has a requirement to operate and maintain its distribution and transmission system in a manner that reflects its focus on customers, productivity, demographics and system reliability and safety. This Application contains FEI's forecast of those costs and a reasonable estimate inflation for 2014 through 2018, based on the Company's 2013 Approved O&M as adjusted.

The level of O&M expenditures in the forecast is reasonable and conservative given known cost pressures that are not reflected in the forecasts included in this section. It is representative of the minimum level of costs that FEI would expect to file for under annual cost of service applications if it were not filing for a PBR Plan.

4. CAPITAL EXPENDITURES

4.1 INTRODUCTION

The Company's capital expenditures involve small and large projects of many types that are required to meet increasing requirements to maintain the safety, reliability and integrity of the distribution and transmission facilities used to provide service to existing and new customers, respond to the information needs and inquiries of the customers, and to provide the information and systems necessary to support the business.

This section discusses the capital expenditures of FEI during the period of 2014-2018 (excluding Allowance for Funds Used during Construction (AFUDC)). A discussion of anticipated Certificates of Public Convenience and Necessity (CPCN) projects is provided in Section C4.7.2. Consistent with past practice, these forecasted CPCN projects have not been included in the rate forecasts in this Application as they are approved through a separate process.

4.2 2014-2018 PBR PLAN CAPITAL CATEGORIES

In this Application, FEI is proposing to set rates for the period 2014 through 2018 using a formula-based approach. It is proposed that the rate base used to determine rates during that period will make use of a formula based approach for calculating capital expenditures traditionally included in Sustainment, Growth and Other Capital. The objective of this classification is to include all controllable capital components of total rate base in the formula while excluding those components of rate base such as deferral account balances and CPCNs that do not relate directly to regular capital expenditures. Deferral accounts and CPCNs would continue to be reviewed and approved by the Commission through separate regulatory processes.

The forecast capital expenditures are provided below for reference purposes only. As discussed above, the capital expenditures for rate setting purposes will be calculated using the formula approach during the PBR period. The forecasts below and the discussion that follows have been prepared at a high level to provide information on the Company's capital priorities and requirements over the upcoming 5 year period.

4.3 REGULAR CAPITAL ADDITIONS: SUSTAINMENT, GROWTH AND OTHER CAPITAL

4.3.1 Categories of Capital Expenditures

The rate base for FEI for 2014 and beyond will be affected by capital expenditures in 2013 and those in the future. Consistent with the 2012-2013 RRA, FEI's regular capital expenditures are divided into the following categories:

- Sustainment Capital – Consists of expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations.
- Growth Capital – Consists of expenditures for the installation of new mains, services and meters.
- Other Capital – Consists of expenditures for Bio-methane Interconnections, Equipment Facilities, and IT.

The Regular capital additions are discussed below in terms of Sustainment, Growth and Other Capital. The tables below provide the historical (2010 through 2013) and forecast (2014 through 2018) capital expenditures for FEI, as well as a reconciliation of the 2013 Base capital expenditures that forms the starting point for the 2014 – 2018 formula and projections.

4.3.2 Historical Capital Expenditures

Table C4-1 below shows the Company's level of capital spending from 2010 through 2013. The reasons for the increased level of spending were explained in FEI's 2012-2013 RRA and approved in Order G-44-12. FEI's 2012 actual capital spending was approximately $8.5 million less than approved as FEI was not able to complete its planned capital work for 2012 partly due to the timing of the 2012-2013 RRA Decision. However, 2013 spending is projected to be approximately $6.5 million higher than 2013 approved amounts. The total actual and projected spending for 2012 and 2013 of just over $226 million ($102.591 million plus $123.781 million) is $2 million or less than 1 percent lower than the approved total of approximately $228 million over the 2012-2013 period.

The capital expenditures net of contributions discussed above exclude expenditures related to the Biomethane upgrader equipment, since the capital related to the upgraders is recovered specifically from Biomethane customers, and is therefore excluded from the formula-based capital expenditures included in this section. The historical Biomethane upgrader equipment expenditures are, however, included in the capital additions to rate base as shown in Section E Schedule 34, Line 50.

Table C4-1: Historical FEI Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Sustainment Capital						
Meter Recalls/Exchanges	19,126	22,922	24,197	20,668	25,062	21,272
Transmission System Reinforcements	9,771	10,808	14,964	20,350	18,005	24,386
Distribution System Reinforcements	5,198	7,670	8,574	7,170	8,691	7,610
Distribution Mains & Service Renewals & Alt.	11,342	17,736	16,556	17,330	20,500	21,845
Total Sustainment Capital	45,437	59,137	64,291	65,517	72,258	75,114
Growth Capital						
New Customer Mains	4,538	4,510	5,374	6,127	5,033	6,500
New Customer Services	13,874	14,423	17,423	12,050	16,791	12,910
New Customer Meters	1,905	1,699	1,403	1,965	1,438	2,105
Total Growth Capital	20,317	20,632	24,200	20,142	23,262	21,515
Other						
Biomethane - Interconnect	504	-	-	1,015	1,100	1,015
Equipment	3,434	3,499	3,951	3,310	3,875	2,930
Facilities	4,177	5,840	1,996	8,424	7,549	4,124
IT	12,418	14,503	13,983	18,000	21,600	18,000
Total Other	20,533	23,841	19,930	30,749	34,124	26,069
Total Gross Capex	86,287	103,610	108,421	116,408	129,644	122,698
CIAC	(3,922)	(7,948)	(5,830)	(5,341)	(5,864)	(5,400)
Total Net Capex	82,365	95,662	102,591	111,067	123,781	117,298

Base and Forecast Capital Expenditures

Table C4-2 below reconciles the 2013 Approved amount to the 2013 Base amount by category. As discussed in Section B2.5 of the Application, the adjustments reflect:

1. the return to PST;
2. the pension amounts related to capital that were included in a deferral account in 2013;
3. the impact on capital expenditures (but not on capital additions) of purchasing vehicles rather than treating them as a capital lease, at the approved 2013 capital lease addition amount; and
4. a change to the capitalization of annual software costs.

Each of these items is described in Section B2.5 of the Application. The table below shows how these items have been allocated to the various categories of capital. Total PST expenditures are allocated based on the total costs attributable to a category of capital as a percentage of total capital expenditures net of contributions. Pension amounts related to capital are allocated based on 2012 actual expenditures for IBEW labour. The percentage split for each category is then multiplied by the total estimated capital related pension amount for 2013.

Table C4-2: 2013 Base Adjustments ($ thousands)

Sustainment Capital	2013 Approved	2013 Adjustments PST	Pension	Vehicles	IT Cap	2013 Base
Meter Recalls/Exchanges	21,272	362	837	-	-	22,471
Transmission System Reinforcements	24,386	416	378	-	-	25,180
Distribution System Reinforcements	7,610	130	118	-	-	7,858
Distribution Mains & Service Renewals & Alt.	21,845	372	339	-	-	22,556
Total Sustainment Capital	75,114	1,280	1,672	0	0	78,065
Growth Capital						
New Customer Mains	6,500	111	172	-	-	6,783
New Customer Services	12,910	220	341	-	-	13,471
New Customer Meters	2,105	36	56	-	-	2,197
Total Growth Capital	21,515	367	569	0	0	22,451
Other						
Biomethane - Interconnect	1,015	17	-	-	-	1,032
Equipment	2,930	50	-	2,860	-	5,840
Facilities	4,124	70	-	-	-	4,194
IT	18,000	307	-	-	1,800	20,107
Total Other	26,069	444	0	2,860	1,800	31,173
Total Gross Capex	122,698	2,091	2,241	2,860	1,800	131,689
CIAC	(5,400)	(92)	-	-	-	(5,492)
Total Net Capex	117,298	1,999	2,241	2,860	1,800	126,197

Table C4-3 below provides the forecast capital expenditures by category, starting from the 2013 Base as calculated above.

Table C4-3: Forecast FEI Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	22,471	25,967	26,852	25,869	24,225	25,085
Transmission System Reinforcements	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains & Service Renewals & Alt.	22,556	25,815	24,433	28,245	34,059	34,304
Total Sustainment Capital	78,065	78,449	79,045	77,198	80,578	82,340
Growth Capital						
New Customer Mains	6,783	5,374	5,462	5,561	5,664	5,798
New Customer Services	13,471	18,360	19,502	20,214	20,337	20,363
New Customer Meters	2,197	1,664	1,805	1,876	1,877	1,862
Total Growth Capital	22,451	25,398	26,769	27,651	27,878	28,022
Other						
Biomethane - Interconnect	1,032	3,908	1,100	1,864	1,864	1,864
Equipment	5,840	6,818	7,328	7,127	7,358	6,702
Facilities	4,194	3,904	4,026	4,122	4,269	4,626
IT	20,107	20,105	20,105	20,106	20,102	20,098
Total Other	31,173	34,735	32,560	33,218	33,593	33,289
Total Gross Capex	131,689	138,582	138,374	138,067	142,050	143,652
CIAC	(5,492)	(5,821)	(5,821)	(5,821)	(5,820)	(5,819)
Total Net Capex	126,197	132,762	132,554	132,247	136,230	137,833

The forecast capital expenditures over the PBR period show an initial increase in 2014, primarily in the growth capital area but also in Biomethane and Equipment. After 2014, capital expenditures are fairly steady in total until they increase again in the 2017 to 2018 period. As stated above, the forecasts included in this section have been prepared at a high level to provide information on the Company's capital priorities and requirements over the upcoming 5 year period.

4.3.3 Inflation Assumptions

FEI's forecast capital expenditures over the PBR period have been prepared using a low inflation scenario, as noted in the sections that follow. However, as discussed below, there is the potential for a high inflation scenario which would impact the forecast capital expenditures.

The potential for high inflation is driven by two primary factors: the anticipated major boom in pipeline projects and the trend of higher construction costs. Each factor is discussed below.

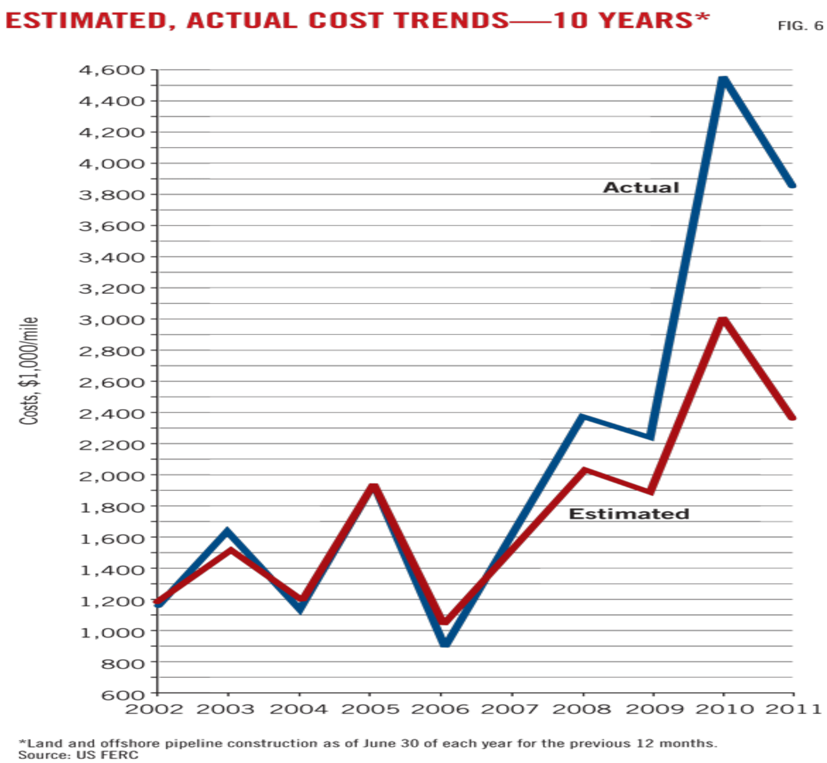
First, the potential for high inflation is driven by the potential major investment boom in pipeline projects, spurred on by the development of new gas resources and demand from LNG export facilities. According to the advisory firm Ernst & Young[56], at least $17 billion of large-diameter pipeline projects tied to proposed export developments in Canada are in the works. The total is more than one-third of an estimated $50 billion in LNG-related infrastructure needed over the next five to 10 years to support export plans. Completing the construction phases of pipeline projects will create a very high demand for labour, materials and resources.

With competition for limited resources as the projects are developed, there is the potential for significant cost escalation risk. The labour and resource shortage issue (such as demand for skilled tradespersons) could be further exacerbated by the resurgence in the forestry and mining sector as well as the potential for other major projects such as BC Hydro's Site C, Enbridge's Northern Gateway pipeline to move Alberta oil sands bitumen to an export hub in Kitimat, BC[57] and similarly Kinder Morgan's oil pipeline to Burnaby, BC.

Such a scenario would result in higher construction costs for FEI in order for it to implement its capital projects, particularly in the area of transmission system reinforcements and CPCN projects that require steel pipe and significant contract and engineering resources. FEI would be competing with other external projects for similar resources and would likely face escalating construction costs for its own capital projects. To illustrate this issue, the graph[58] in the following Figure C4-1 shows 10 years of estimated vs. actual costs on a cost-per-mile basis for natural gas pipeline projects completed in the US as reported to the US Federal Energy Regulatory Commission (FERC).

[56] From Financial Post article titled "Canada could face massive hurdles in move to build $50B methane superhighway" – February 28, 2013.
[57] From Pipeline News North – May 10, 2013
[58] From Oil and Gas Journal – Oil pipeline operators' 2011 profits soar to record - September 03, 2012

Figure C4-1: 10 Year History of Estimated vs. Actual Cost-Per-Mile for US Natural Gas Pipeline Projects



Second, pipeline costs are rising, most notably in recent years, with actuals costs exceeding the original estimates by a fair margin, demonstrating the challenge of estimating rising construction costs in the current environment. Based on the numbers compiled by the Ziff Energy Group in its report released on June 29, 2011 discussing the current trends in North American pipeline construction costs, with the focus on large pipeline projects, the cost of pipeline construction has tripled since 2004 to a pipeline diameter inch-mile cost of nearly $200 thousand, driven by higher prices for steel, labour and environmental factors. Contributing to the rising construction costs is that the price of steel has gone up by 30 percent in a year.

Based on the above, under a high inflation construction cost scenario, FEI is projecting a potential annual inflation rate in the last three years of the PBR Period for construction costs of 20 percent, which would be within the range of what has been observed in recent past. In the capital expenditure discussions that follow, FEI has used an estimated inflation rate of only 2 percent per year as a low inflation scenario. For illustration purposes, the impact of this potential high inflation scenario on the transmission system reinforcement components of the total capital expenditures is reflected in the graphs provided in Section B which compares the forecast capital expenditures to the amounts that are allowed under the PBR formula approach. A discussion of the potential impact on FEI's capital forecasts due to a high inflation scenario is included in Section B2.5.2.

4.3.4 Asset Management Strategy

At FortisBC, we are pursuing the development of a common Asset Management Strategy across both the gas and electric divisions with the objective of improving maintenance and capital investment decisions, planning, and program execution. The Asset Management Strategy will incorporate established industry practices derived from the international PAS55 standard, while leveraging the systems and processes that are already in place in both the gas and electric divisions. The PAS55 Standard[59] (Publicly Available Specification 55) is published by the British Standards Institute and is recognized as a leading standard for assessing asset management in organizations. Processes that the Asset Management Strategy will leverage include the gas division's Long Term Sustainment Plan and the Electric division's Integrated System Plan. These processes will be supported by existing information systems, which will be integrated to provide an optimized, single view of how the Utilities manage both gas and electric assets.

4.4 *SUSTAINMENT CAPITAL EXPENDITURES*

4.4.1 Sustainment Capital Overview

The expenditures within sustainment capital include gas system improvements to ensure adequate capacity within the transmission and distribution system in order to meet forecast load and to ensure the safety, reliability and integrity of the system.

Sustainment capital includes expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations.

The historical and forecast sustainment capital expenditures for transmission and distribution systems for FEI are summarized in Tables C4-4 and C4-5 below.

Table C4-4: Historical Sustainment Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
System Integrity and Reliability Capital						
Meter Recalls/Exchanges	19,126	22,922	24,197	20,668	25,062	21,272
Transmission System Reinforcements	9,771	10,808	14,964	20,350	18,005	24,386
Distribution System Reinforcements	5,198	7,670	8,574	7,170	8,691	7,610
Distribution Mains and Service Renewals/Alterations	11,342	17,736	16,556	17,330	20,500	21,845
	45,437	**59,137**	**64,291**	**65,517**	**72,258**	**75,114**

[59] PAS55 is published by BSI British Standards using the rigour of a Publicly Available Specification. The International Standards Organisation (ISO) has now accepted PAS55 as the basis for development of the new ISO 55000 series of international standard. For more please visit http://theiam.org/

Table C4-5: Forecast Sustainment Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
System Integrity and Reliability Capital						
Meter Recalls/Exchanges	22,471	25,967	26,852	25,869	24,224	25,085
Transmission System Reinforcements	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains and Service Renewals/Alterations	22,556	25,815	24,433	28,245	34,059	34,304
	78,065	**78,449**	**79,045**	**77,198**	**80,578**	**82,340**

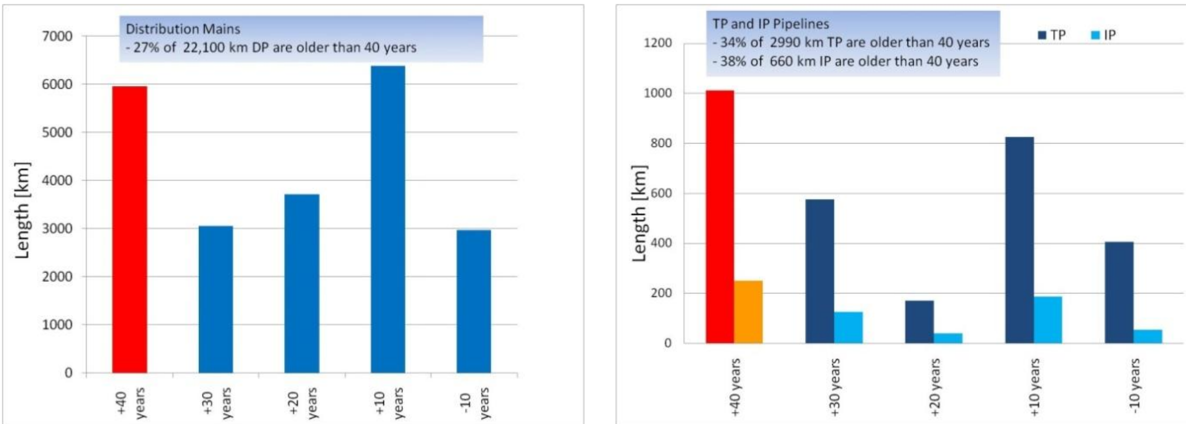
As Table C4-4 above illustrates, sustainment capital expenditures increased from 2010 through 2013, as anticipated and discussed in the 2012-2013 RRA. As a result of not completing all of the planned capital work in 2012, the actual sustainment capital expenditures were approximately 2 percent less than the total approved sustainment capital expenditures of approximately $65.5 million. The 2013 sustainment capital expenditure projection is approximately 4 percent lower than the 2013 approved amount of approximately $75 million. To a limited extent the timing of the decision on the 2012-2013 RRA impacted planning efforts in 2012 and 2013; however, more significantly, there has been an increase in the amount of time required to plan, design and execute capital work due to changing requirements from municipalities and other interested parties. Due to strategies and processes that have evolved, FEI is confident the capital expenditures currently projected for 2013 will be met.

4.4.2 Approach to Sustaining Capital Expenditures

FEI is responsible for gas transmission and distribution assets with a rate base value of approximately $2.6 billion, and an approximate replacement value of $6.1 billion. Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines (Figure C4-2) have been in service for 40 to 55 years. Some of these assets will be facing an increasing rate of deterioration and upon further analysis replacement may be warranted.

During the initial preparation of the forecast for sustaining capital expenditures, the age of the infrastructure was the original and primary driver for initiating a review of the health of the assets and the potential requirement for replacement. However, during the development of this approach a better understanding of asset health, failure modes and the factors affecting such has resulted in an assessment of assets based on their condition. This enables the development of asset maintenance and renewal programs that ensure continued safe, reliable operation of the system, regardless of the age of the assets.

Figure C4-2: Proportions of Transmission and Distribution Approaching Life Expectancy

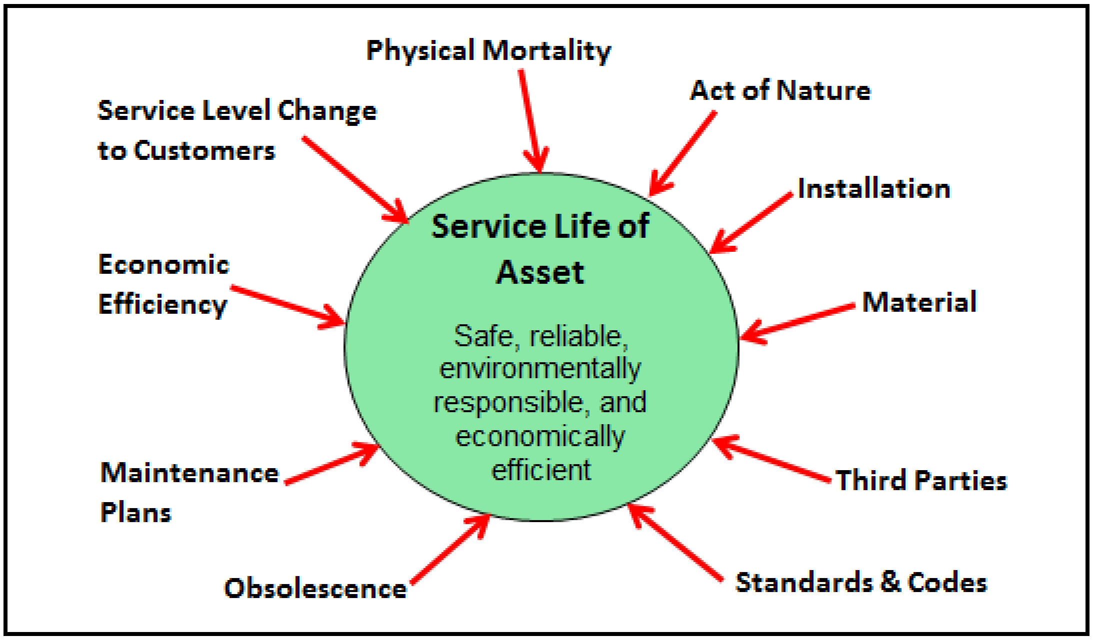


Distribution Main Age **Transmission and Intermediate Pressure Pipe Age**

Based on only the average service life of FEI's pipeline assets, it could be projected that a significant portion of the pipes would need to be replaced starting within the next 10 years. In addition to the difficulties associated with attempting to undertake such a large amount of work in a short period of time, such as resourcing and maintaining customer supply, if such a large group of assets were to be retired from service over a short period, it would cause a significant spike in costs for asset replacement and a corresponding spike in rate increases for customers. In order to moderate rate increases while maintaining safety and reliability, FEI must make prudent and informed decisions that ensure resources are allocated where they are most effective at mitigating risks. The key is to improve the understanding of the service life of each asset group and the factors impacting that service life. This process is also discussed in greater detail in Appendix C3 – Long Term Sustainment Plan (LTSP).

Examples of asset groups include pipelines, mains, services, meters, compression equipment, measuring equipment and regulators. Generally speaking, factors that impact the expected service life of an asset include normal wear and tear, maintenance plans, and other external factors such as obsolescence, changes in codes and standards, economic efficiency, changes in service requirements, acts of nature, and third party damages, as illustrated in Figure C4-3 below.

Figure C4-3: Many Factors Impact the Service Life of an Individual Asset



While asset groups tend to have an expected service life that is affected by many factors, the expected service life of assets can be extended through the implementation of preventative maintenance programs. FEI has many programs that not only monitor and inspect the condition of the assets, but also undertake actions to maintain or extend the expected service life of the assets.

FEI's asset management programs range from simple actions, such as lubricating valves or replacing small components of regulators, to the more complex, such as undertaking the analysis of in-line inspection (ILI) data for transmission lines to identify where corrosion is active so that corrective action can be focused and effective. There are many other examples where decisions are made or actions are taken that result in the expected service life of an asset being extended, including:

- To increase system capacity, parallel gas lines (loops) are usually installed rather than replacing the existing gas line unless the existing gas line has integrity concerns such as a history of leaks.
- To increase gate station life expectancy, components of regulators are replaced rather than the entire regulator unless the regulators are obsolete or unusual in style or design. Similarly, regulators or other equipment can be replaced or upgraded without replacing the entire station.
- If the incremental cost of installing slightly larger piping in stations is not significant then initially the larger piping will be installed with smaller equipment such as regulators, filters and line heaters. As capacity demands increase, the equipment is modified, as

described above for regulators, until such time that no flexibility remains and the equipment is replaced, but the station piping, much of which is buried, remains in service.

- Aside from third party requests, mains renewal or replacement may be driven by the frequency of leaks occurring on a segment of main, the cost of addressing each successive leak, the Company's ability to prevent any further leaks and the potential consequences of future leaks occurring. Age is generally not determinative except in helping to determine the technology and procedures in place at the time of installation.

Through an ongoing asset management program and ongoing examination of asset failure modes, causes and the effectiveness of various mitigation efforts, FEI has gained a better understanding of asset condition and appropriate reliability sustainment programs. These programs vary from preventive measures such as cathodic protection to reactive measures such as leak survey. Understanding how and why an asset fails and the risks associated with those failures also enables development of appropriate sustainment programs that minimize costs while ensuring the ongoing safety and reliability of the natural gas delivery system. This is discussed in more detail below and in Appendix C3.

4.4.3 Long Term Sustainment Plan Update

In response to the challenge posed by aging infrastructure, in 2010 FEI proposed a long-term capital planning approach, or Long Term Sustainment Plan as an asset management process enhancement. The LTSP has enabled FEI to create and support long term asset replacement plans and capital expenditures by developing a relative risk framework that continually measures asset health and identifies specific areas of concern that require further evaluation or action. This relative risk framework provides a tool that, in conjunction with FEI's other Integrity Management Program activities, facilitates proactive decision making on appropriate mitigating actions. This in turn will assist in ensuring asset replacements are made only where needed and supported by data, thereby reasonably minimizing the need for early asset retirements.

The 2012-2013 RRA Decision directed the FEU to provide a status update on the LTSP, systems developed and the nature of assets replaced in their next revenue requirements application.[60] A detailed discussion of the LTSP and response to the Commission direction is provided in this section, with further details in Appendix C3 of this Application.

Status Update on the LTSP

FEI has been proactive in implementing the LTSP, convening a LTSP project team that has developed:

[60] 2012-2013 RRA Decision Directive No. 38 Page 93 and Appendix A, p. 7

- An enhanced understanding of asset condition as it relates to the reliability of natural gas delivery assets over the long-term;
- A methodology to identify and prioritize the work required to maintain asset reliability; and,
- A list of future projects and programs required to maintain system safety and reliability while protecting customers from sharp rate increases.

The project team, comprised of personnel with a variety of backgrounds, drew heavily on company operating experience to gain an improved understanding of the asset failure modes and causes. The team developed the first iteration of the LTSP process and applied it to create long-term sustainment capital plans for FEI's Distribution and Transmission assets. Further information on the development of the LTSP is in Appendix C3.

Systems Developed

The main system developed by the LTSP is the methodology by which asset conditions are assessed and areas of high risk relative to other assets of a similar type are brought to Asset Management's attention for further action. The results generated by the methodology provide an additional tool for Asset Management staff to administer the ongoing safety and reliability of the natural gas delivery system and to maximize the value of existing assets by ensuring replacements are made only where and when they are needed.

The LTSP project team created a methodology to evaluate, for each asset, the relative probability and consequence of failure which together reflects the level of relative risk present in FEI's assets. The relative probability, consequence and risk are expressed by means of a numerical score calculated via customized criteria evaluating possible failure modes and causes. The LTSP analysis was made possible using Geo-Spatial Analysis (GSA) software developed by General Electric, and a custom Microsoft Access Database application. The GSA software is capable of extracting data from FEI's Geographical Information System in real-time, as well as data from other enterprise systems and records. The data input into the risk assessment is objective and represents the most current available information, supplemented by manual analysis where necessary. The team also undertook a validation process on the methodology, tools and results of the LTSP with operations and engineering staff. FEI believes that the results of the assessment are a reasonable representation of the current condition of FEI's system. Please refer to Appendix C3 for detailed information.

The risk scores derived using the methodology for each asset and, more specifically, the factors used to calculate the scores can be used to evaluate asset condition and pinpoint areas for replacement or mitigating actions. The results support the decisions of Asset Management staff in identifying long-term programs and projects, and in prioritizing those programs and projects relative to one another. Programs and projects identified are added to FEI's capital projects and executed under existing processes.

Nature of Assets Replaced

The first iteration of the LTSP focuses mainly on FEI's Distribution and Transmission pipeline assets. The GSA software enables Asset Management staff to identify and prioritize specific distribution mains for further investigation, mitigation actions, or renewal. The expenditures for Distribution Mains and Services Renewals identified in this manner are included within the forecast Sustainment Capital expenditures in this Application. The same risk assessment methodology is applied to Transmission pipelines as well. Due to the significant costs of transmission pipeline replacements, these are expected to exceed the $5 million CPCN threshold. Major transmission pipeline projects identified through the LTSP will be subject to further investigation by FEI's Engineering staff and then potential projects will be filed separately as CPCNs.

Note that the LTSP is not the only process by which Distribution and Transmission pipelines are identified for replacement. Requests for sustainment capital work may arise directly from IMP activities, and data from IMP activities can be a valuable input into the LTSP. The LTSP can also support IMP activities by directing attention to areas of interest.

Sustainment capital work relating to facilities such as compressor stations and LNG facilities are addressed on a site specific basis and long term equipment upgrades and replacements have been identified by operating staff. Other facilities such as Pressure Regulating Stations are regularly maintained and monitored by Asset Management personnel. Upgrades to these regulating stations are addressed as per Asset Management's existing practices. Sustainment capital expenditures relating to facilities are included in the amounts forecast for Distribution and Transmission System Reinforcements/Integrity and Reliability.

4.4.4 Meters and Regulators - Exchanges

This section contains a discussion of Sustainment Capital expenditures related to meter exchanges and regulator ever-greening requirements.

Meter exchange is the activity of removing in-service gas meters and replacing them with new or refurbished meters to maintain accurate measurement in accordance with the Electricity and Gas Inspection Act. Depending upon the cost of repair relative to the remaining asset value, the exchanged meter is refurbished or permanently taken out of service.

Regulator ever-greening is the activity of removing long service and obsolete in-service gas regulators and replacing them with new regulators. When an older regulator is noted during a meter exchange, the two activities are completed on the same customer visit. Regulators, which are a relatively low-cost, long-lasting piece of equipment, are not tracked individually in the same manner as meters. Older and obsolete regulators are identified for replacement by meter readers and leak survey technicians in the course of routine operations activities. Regulator replacement work orders are created and subsequently dispatched to both internal and external resources.

Tables C4-6 and C4-7 summarize historical and forecast expenditures for the combined meter exchange and regulator exchange programs for FEI.

Table C4-6: Historical Meter Exchange and Regulator Exchange Programs ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Meter Exchanges	16,873	18,496	19,350	19,062	18,945
Regulator Evergreening	2,253	4,426	4,847	6,000	2,328
	19,126	**22,922**	**24,197**	**25,062**	**21,272**

Table C4-7: Forecast Meter Exchange and Regulator Exchange Programs ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Meter Exchanges	20,012	21,653	22,469	23,528	24,017	24,876
Regulator Evergreening	2,459	4,314	4,382	2,342	209	209
	22,471	**25,967**	**26,852**	**25,869**	**24,225**	**25,085**

The key factors that influence the forecasted meter exchange and regulator ever-greening expenditures include the level of meter exchange activity, the average meter unit costs and the regulator ever-greening requirements. Expenditures for meter exchange and regulatory ever-greening are discussed below.

Meter Expenditures

Meter capital expenditures are summarized in the tables below. These expenditures are based on (i) base meter exchange activity levels (scheduled and unscheduled), plus additional meter exchanges forecast in 2014-2018 as a result of changes to standards and regulations, (ii) multiplied by historical blended meter unit costs. Activity levels and unit costs are discussed in more detail below.

Tables C4-8 and C4-9 below summarize both scheduled and unscheduled meter exchange activities, together with the average meter unit cost and the capital dollar requirement of the base meter exchange program. Table C4-9 summarizes the impacts of the incremental meter exchange program as a result of changes to regulations in 2014 impacting years 2014-2018. Table C4-9 also summarizes the total meter exchange (base and incremental) forecast together with total meter exchanges, and an overall adjusted meter unit cost.

Table C4-8: Historical Meter Exchange Activities & Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Meter Recalls - Scheduled	58,403	57,511	62,141	58,900	58,900
Meter Recalls - Unscheduled	3,137	3,450	2,956	3,000	3,400
Total Meter Recall Activity	61,540	60,961	65,097	61,900	62,300
Unit Cost ($/meter)	274	303	297	308	304
Subtotal Meter Recall Expenditures	16,873	18,496	19,350	19,062	18,945
Incremental Recalls	-	-	-	-	-
Unit Cost ($/meter)	-	-	-	-	-
Subtotal Incremental Meter Recall Expenditures	-	-	-	-	-
Total Meter Recall Expenditures	16,873	18,496	19,350	19,062	18,945
Total Meter Recall Activity	61,540	60,961	65,097	61,900	62,300
Adjusted Unit Cost	$ 274	$ 303	$ 297	$ 308	$ 304

Table C4-9: Forecast Meter Exchange Activities & Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Meter Recalls - Scheduled	58,900	58,900	58,900	58,900	58,900	58,900
Meter Recalls - Unscheduled	3,400	3,000	3,000	3,000	3,000	3,000
Total Meter Recall Activity	62,300	61,900	61,900	61,900	61,900	61,900
Unit Cost ($/meter)	$ 321	$ 328	$ 333	$ 339	$ 346	$ 359
Subtotal Meter Recall Expenditures	$ 20,012	$ 20,279	$ 20,594	$ 20,984	$ 21,418	$ 22,201
Incremental Recalls	-	9,915	13,415	17,915	17,915	17,915
Unit Cost ($/meter)	-	$ 139	$ 140	$ 142	$ 145	$ 149
Subtotal Incremental Meter Recall Expenditures	-	$ 1,374	$ 1,875	$ 2,544	$ 2,599	$ 2,675
Total Meter Recall Expenditures	$ 20,012	$ 21,653	$ 22,469	$ 23,528	$ 24,017	$ 24,876
Total Meter Recall Activity	62,300	71,815	75,315	79,815	79,815	79,815
Adjusted Unit Cost	$ 321	$ 302	$ 298	$ 295	$ 301	$ 312

Meter Exchange Activity

Meter exchange activity is the first consideration in establishing the forecast expenditure for meter exchanges. The forecasted level of meter exchange activity is the combined total of scheduled and unscheduled meter exchanges (residential, commercial and industrial) required so that customers continue to receive service that is both cost effective and reliable while remaining in compliance with regulatory requirements.

Scheduled meter exchange activity levels are driven by factors related to Measurement Canada's mandatory standards and regulations. Measurement Canada allows utilities to operate their meter fleets by applying a compliance sampling plan to confirm meters used for billing customers are accurate. Compliance sampling is the process of randomly selecting a subset of meters from a group of installed meters, testing the samples and inferring the quality of the remaining installed meters in that group from the test results of the samples.

Effective January 1, 2014, this sampling plan is changing and all utilities in Canada will be adjusting their meter fleet management strategies to meet the new requirements. The sampling plan, referred to as SS-06, incorporates tighter tolerances and stricter criteria for allowing meters to remain in service. For example, the current sampling plan assesses the performance of a group of meters based solely on the average of sample test results and excludes eligible outliers. Alternatively, the new sampling plan assesses the performance of a group based on the number of samples meters that exceed the allowable tolerances. Furthermore, the new sampling plan includes all outliers in the performance assessment of a group of meters. Therefore, by applying this new approach to determine meter performance, the potential for a given group to fall outside of Measurement Canada's requirements increases. As a result of this new sampling plan, gas utilities across Canada are expecting to experience a requirement to increase the number of scheduled meter exchanges.

The unscheduled meter exchange activity is forecasted based upon previous experience and represents meters that are exchanged during the course of the year that were not part of the original schedule. Unscheduled meter exchanges occur as a result of unanticipated changes to customer metering needs, administrative requirements such as load changes as well as mechanical failures and may have been identified by a customer, a meter reader or other gas technician.

For the period between 2010 and 2012, the actual meter exchange activity was close to approved levels. The approved exchanges for 2010 were 60,225 with actuals of 61,540. For 2011 the approved exchanges were 60,175 with actual exchanges of 60,961. For 2012 the approved exchanges were 62,350 with actual exchanges of 65,097. Furthermore, in 2013 FEI had forecast 62,300 meter exchange recalls and is projecting to be very close to that level.

FEI forecasts an increase in the residential meter exchange activity beginning in 2014 in order to remain compliant with the new sampling plan mandated by Measurement Canada. As stated earlier, this sampling plan has more stringent requirements and as a result, FEI expects to experience an increase in the number of meters that are not compliant and therefore are required to be replaced.

Meter Unit Costs

Aggregate or blended meter unit cost is the second consideration in establishing the forecast expenditure for meter exchanges. The unit cost is calculated as follows:

$$\frac{\textit{Total Meter \& Regulator Capital Dollars (less Regulator Ever-greening Program)}}{\textit{Total Meters for Net New Customer Additions and Meter Exchanges}}$$

The meter unit cost is influenced by the type, the size, the design of the meter, the installation, fabrication and exchange conditions of the meter set and the timing of the bulk meter purchases and meter upgrade activity. A blended unit cost of all customer types is used for meter exchanges. Meter unit costs typically range from $75 to $10 thousand depending on the customer requirements.

In 2012 the Meters and Regulators capital expenditures consisted of 68 percent materials (primarily meters and regulators) with labour, both COPE (planners) and IBEW (field) making up the residual one third. The average blended meter unit cost was $297 per meter in 2012. Unit costs for 2014-2018 are primarily based on 2012 actuals and forecast inflation of 2 percent per annum. The forecast inflation rate is based on expected material (meter) cost inflation as well as forecast IBEW and COPE labour rate increases.

For 2014-2018 incremental meter exchanges driven by compliance to new Measurement Canada standards, a lower per meter unit cost of $139 was used to forecast the capital expenditure impact. The additional meter exchange activities driven by Measurement Canada are in the residential meter types where the cost of the meter is generally lower than the average blended meter unit cost. The $139 unit cost also includes a field labour component to complete the exchange.

Regulator Ever-greening

Regulator ever-greening is the activity of removing older and obsolete in-service gas regulators and replacing them with new regulators. Regulators, unlike meters, do not have formal replacement programs in place and have typically been replaced for safety reasons due to age, type, and condition. Tables C4-6 and C4-7 above summarize historical and forecast expenditures for the regulator exchange program.

The need for regulator replacements may be identified through routine operating activities such as meter exchanges, meter reading and leak surveys. It may also be identified by notification from suppliers that they will no longer support the equipment or that spare parts will no longer be available. If a need for a regulator replacement is identified, then there is a system-driven requirement to identify the address, type of replacement required and reason for replacement. These are generally lower priority hazards that are batched together for completion and used to minimize standby time where technicians or crews may otherwise not have enough customer driven work. The regulator exchanges are completed by both internal and external technician resources.

FEI has actively identified and replaced regulators since 2003. However, as of the end of 2012, there are still some 70,000 of these identified regulator replacements outstanding. The Company intends to eliminate these over the next three years at a rate of 15 to 20 thousand per year, using a combination of available external and internal resources. Once the backlog of outstanding identified regulator replacements has been eliminated, nominal levels of on-going regulator replacements will continue for the 2017-2018 period.

4.4.5 Transmission System Reinforcement, Integrity and Reliability Capital

The Transmission-related capital expenditures included in Table C4-4 above include system capacity improvements to meet existing customer demand and forecast load, and expenditures related to ensuring safety, reliability and integrity of the transmission system, as well as to minimize the impact to the environment.

Between 2014 and 2018 projects that are forecast to cost greater than $1 million and that are included in the Transmission System Reinforcements line of Table D2-4 are discussed below and have been organized based on common issues. The projects include an estimated cost and an indication of the year during which they are anticipated to be completed and during which the majority of the costs will be incurred.

Pipeline Class Location Upgrades

Clause 4.3.2 of CSA Standard Z662, *Oil and gas pipeline systems*, defines limitations on operating stress (safety factor) based on the number of dwellings within 200 m of the pipeline. An increase in the density of dwellings adjacent to a pipeline may result in the class location being changed leading to a requirement to reduce the operating stress of the pipeline and thus increase the factor of safety. CSA Z662 also requires annual assessments of the class location to recognise and accommodate development near the pipeline. In instances where the class location is changed as a result of development FEI must change the operating parameters of the pipeline. This may require reducing the operating pressure which leads to a loss of capacity and may limit the ability to meet customer demand. In instances where reducing operating pressure is unacceptable, the impacted section of pipeline must be replaced to meet the required safety factor while maintaining customer supply.

The projects listed below involve the replacement of sections of pipelines due to adjacent development and are anticipated to exceed $1 million over the 2014-2018 forecast period:

- 2731m (6 segments) of 1957 vintage 273mm OD Savona Nelson Mainline, East of Oliver (2014) – approx. $4.1 million;
- 697m (10 segments) of 1957 vintage 323mm OD Savona Nelson Mainline, West of Kamloops and West of Vernon (2015) – approx. $1.2 million;
- 2206m (4 segments) of 1957 vintage 114mm OD Williams Lake Lateral, Williams Lake (2015) – approx. $3.3 million;
- 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston (2016) – approx. $1.3 million;

- 1291m (2 segments) of 1957 vintage 168mm OD Prince George #1 Lateral, Prince George (2016) – approx. $1.9 million;
- 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk (2017) – approx. $2 million; and
- 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks (2018) – approx. $4.5 million.

Natural Hazards Mitigation

FEI's operating programs monitor depth of cover at water crossings, the stress on pipelines at sites of moving or unstable slopes, and the resistance of pipelines with regard to seismic events. The following project is required to prevent the loss of pipeline integrity as a result of natural hazards.

Pitt River Pipeline Crossing Replacement, 323mm OD Livingstone to Coquitlam Pipeline, Port Coquitlam & Pitt Meadows (2016)

- The pipeline crossing of this river is both shallow and susceptible to high stresses as a result of ground movement due to a moderate seismic event. Options have been considered and a 900m long horizontally directionally drilled pipeline crossing is proposed. The approximate cost is $3.5 million.

Tilbury LNG Plant Upgrades

The Tilbury LNG plant plays an important role in the operation of the FEI system. The Tilbury LNG plant is a peak shaving facility and provides an alternate source of supply during some types of pipeline work, a source of supply of LNG for use in planned or emergency work within the Company's distribution systems. A high degree of reliability is required for this facility. The proposed expenditure at the Tilbury LNG Plant during the 2014-2018 period is estimated to be $13.9 million which represents an average of approximately $2.8 million per year. This is approximately $2 million per year higher than expenditures in previous years; however the future expenditures are believed to be necessary to maintain the reliability and safety of the existing plant.

A number of projects that exceed $1 million have been identified that will ensure the continued reliable and safe operation of the Tilbury LNG Plant over the 2014-2018 forecast period.

Electrical Equipment (2014) – estimated $2.7 million

- Recent changes to the provincial Electrical Code as well as some deterioration and obsolescence necessitate the need to upgrade the electrical supply for the plant.

Inlet and Outlet Pipelines Replacement (2015) – estimated $2 million

- The two pipelines operating as the inlet and outlet for the plant (323mm and 168mm) pass through an area that is known to have a high potential for seismically induced liquefaction. This would result in significant lateral spreading and potential failure of both pipelines under a moderate seismic event. Replacement of 550m sections of the pipelines at a greater depth (approx. 20m) by horizontally directional drilling is proposed.

Second Pump for Loading Tankers (2015) – estimated $1 million

- Only one pump exists for loading LNG tankers and if this pump failed the repair or replacement likely could not be accomplished in a timely manner. A second pump is proposed to be installed as a standby pump to ensure the ability to fill LNG tankers, respond to requests for emergency LNG supply, and to provide LNG for planned distribution system alterations.

Air cooler (2018) – estimated $3 million

- Replacement is required as age related deterioration is not preventable. Failure generally occurs due to fins lodging to tubing without warning and results in a complete loss of liquefaction capability. An unplanned repair would likely take significant time and would reduce supply for emergency and planned distribution alterations and peak shaving.

Buildings (2018) – estimated $1 million

- Upgrade of control and administration building to current standards including ensuring design to post significant seismic event operability.

4.4.6 Distribution System Reinforcement, Integrity and Reliability Capital

The Distribution System Reinforcement expenditures included in Table C4-4 above primarily consist of improvements to pressure regulating stations and installation of distribution mains to increase the capacity or reliability of the stations or the distribution systems.

Generally these projects are below $1 million; however, on occasion some are much more complex than average. One project planned to be undertaken is expected to be in excess of $1 million:

Trenton Gate Station Replacement – Port Coquitlam (2014)

- The replacement of the Trenton Gate Station is to address undersized piping, an unreliable line heater, and add a station inlet filter and telemetry. This station supplies both DP and IP systems and thus is larger than a typical community gate station. The replacement has been proposed since 2006, but has been deferred due to nearby transportation projects, including the upgrade to the intersection of the Mary Hill Bypass with the Lougheed Highway and the construction of the new Pitt River Bridge, in order to determine the impact of this work upon the station site. As well, deferral of construction has occurred in order to undertake negotiations for additional land as the existing site is an odd shape and use is restricted by overhead power lines and adjacent wet lands. Approximate cost is $1.2 million.

4.4.7 Distribution Mains, Service Renewals and Alterations Capital

The expenditures in the Distribution Mains and Service Renewals/Alterations category included in Table C4-4, primarily consist of replacement of intermediate pressure and distribution pressure mains and services either to address integrity concerns identified by the Company or to address location concerns raised by others. This category also includes upgrades to the Revelstoke Propane Plant and the installation of new pressure regulating stations. It is in this category that FEI foresees the greatest increase in expenditures during the next five years and beyond.

FEI has recently implemented a spatial software tool (see Appendix C3 – Long Term Sustainment Plan) to facilitate a longer term assessment of distribution assets. This spatial software tool interfaces with the Company's GIS and helps to identify the piping having a higher relative risk associated with pipe failure and thus the piping that needs further assessment and possibly replacement. The primary objective is to address piping that is more likely to have integrity-related concerns in a proactive, planned manner, before the concerns result in leaks requiring an emergency response.

By assessing and undertaking work in this manner the replacement work can be undertaken at a lower cost than multiple repairs, and the work will be less disruptive to the municipalities, the public and FEI's customers. Further, with sufficient assessments completed, the replacement projects can be coordinated with municipal infrastructure upgrades thus reducing the impact on the public further. With the improved understanding of the condition and the risks associated with failure of the pipe, FEI has identified a number of instances where replacement is warranted. While this also means that the number of sections of mains that require replacement will increase, it also ensures that the identification of those mains and the decision to replace a piece of pipe is consistent and supported by methodology that ensures the main being replaced really does need to be replaced. As identified in the 2012-2013 RRA, (page 350, section 6: Rate Base) this work will include replacement of unprotected steel mains with polyethylene pipe in order to achieve compliance with CSA Standard Z662.

In recent years based on discussions with and requests from the Ministry of Transportation and municipalities it is evident that they are increasing the amount of work to maintain or upgrade their infrastructures (e.g. Gateway Project, Fraser Hwy upgrades in Surrey). This has also been confirmed by various municipalities during meetings initiated by FEI to introduce the results of the LTSP. As a result of their planned work FEI often has to undertake pipe replacement work to accommodate their designs. The work undertaken by FEI usually takes the form of cutting out or abandoning an existing section of pipe and installing new pipe in a new vertical or horizontal alignment. Existing pipe is almost never recovered as the cost of excavating and removing the pipe is prohibitive, thus often even relatively new mains and services could be abandoned (retired). The cost of these replacements may or may not be recoverable from the party initiating the work, depending on the terms of any agreement or permit that exists. It is often very difficult to predict or plan for these projects.

The projects discussed below are anticipated to exceed $1 million over the 2014-2018 forecast period:

Lougheed Hwy Main Replacement Project – Burnaby (2014)

- The Lougheed Highway Main Replacement project consists of replacing approximately 4.5km of existing 168mm steel main with polyethylene pipe along the existing route or along another, as the existing pipe was installed in the original shoulder of the road and was installed on supports. With subsequent widening of the road over the pipeline and repeated flexing of the pipe due to traffic load, there have been a number of failures of the oxy-acetylene welds, the most recent in 2008 when 500 homes were evacuated. The installation of new pipe will also reduce the probability of a significant interruption to the operation of the Skytrain[61] and interference with the Loughheed Highway. Other sections of the steel main have been replaced in the past. Design and community relations activities have been undertaken and the first phase of the replacement is occurring in 2013 ($410 thousand). The proposed expenditure in 2014 is $1.3 million.

Penticton Second Supply – Penticton (2015)

- The distribution system in and adjacent to the City of Penticton is presently served by one gate station. The configuration of the distribution piping exiting and heading away from the station is such that a failure of one major branch, for example, from third party damage, will result in the interruption of service to a significant portion of the town. There are approximately 13,000 customers served by the existing station and it is proposed that a second gate station be installed along with a large supply main into the central portion of town. This will reduce the likelihood of a single event affecting a majority of the entire customer base. The plan to install a second source of supply to the City of Penticton has been in existence for many years. In about 1980 the site for the second gate station was purchased in the NE corner of Penticton. The estimated cost for installing an additional gate station and the distribution system improvements is $2.4 million (approx. 10 percent will be incurred in 2014).

Pattullo Bridge Replacement – Surrey / New Westminster (2015)

- The replacement of the Pattullo Bridge that crosses the Fraser River between the cities of Surrey and New Westminster is planned by Translink. FEI has a 508mm OD pipeline

[61] On February 11, 2008, a weld in the 168mm OD distribution pressure main cracked. This resulted in the evacuation of 500 homes, the closure of the Lougheed Highway and shutdown of Skytrain. Skytrain was shutdown approximately 4 hours while the Lougheed Highway was closed for 6 hours after which 50 percent of the lanes were re-opened.

on this bridge (installed about 1970) currently operating at 700kPa (with a potential to operate at 1200kPa). The pipeline supplies a large portion of New Westminster and the eastern portion of Burnaby. FEI has confirmed that a pipeline crossing at this location is required and preliminary agreement has been obtained for approval to install a new gas line on the new bridge. In this instance the existing pipeline is subject to the conditions of a "Highways Permit" which includes the requirement that FEI is responsible for any alterations to the gas line as a result of work on the bridge. At the present time it is our understanding that FEI may have to install a new pipeline on the new bridge during 2015; however, this could be deferred as a result of decisions by other parties. The estimate for the total project is $2.7 million.

4.4.8 System Sustainment Capital Summary

Overall, sustainment capital expenditures are forecast to increase throughout the PBR period, from approximately $78 million in the base year 2013 to approximately $82 million forecast in 2018. This represents, on average, an increase of approximately 1.1 percent annually throughout the RRA period. Major transmission pipeline projects identified through the LTSP will be subject to further investigation by FEI's Engineering staff and potential projects will be filed separately as CPCNs.

Meter Recalls/Exchanges show a step increase from approximately $22.5 million in the 2013 base year to approximately $26 million in 2014, and then remain relatively flat throughout the RRA period with $25.1 million forecast in 2018. As discussed in Section C4.4.4, the main drivers of this forecast include regulatory changes that have led to tighter tolerances and stricter criteria for granting of seal extensions, changes to compliance sampling rules, performance degradation of meters due to construction changes, and the anticipated completion of the regulator ever-greening project.

Transmission System Reinforcements are projected to decline from approximately $25.2 million in the 2013 base year to approximately $16.6 million in 2014, increase to approximately $20.5 million in 2015 and then decline from $15.5 million in 2016 to $14.3 million in 2018. The drivers of this forecast include development in areas adjacent to FEI's pipelines, the identification of natural hazards requiring mitigating action, and upgrades to the Tilbury LNG Plant.

Distribution System Reinforcements are forecast to average approximately $8 million per year throughout the forecast period, with a one-time increase to approximately $10 million in 2014 due to additional station upgrades planned for that year (such as the Trenton Gate Station upgrade discussed in Section C4.4.6.

Distribution Mains and Service Renewals/Alterations are expected to grow steadily throughout the RRA period, increasing from approximately $22.6 million in the 2013 base year to $34.3 million in 2018, an average annual growth rate of 8.7 percent per year. And as discussed in Section C4.4.7, this increase is a result of increased activities by the Ministry of Transportation and also municipalities focused on upgrading their respective infrastructures, and also due to the implementation of the LTSP as a tool to complement ongoing Integrity Management Program (IMP) activities which has enhanced FEI's ability to develop long-term plans.

In summary, the level of capital expenditures projected throughout the 2014-2018 forecast period represent those improvements identified by FEI as required for its transmission and distribution system to ensure the ongoing safe, reliable, and economically efficient delivery of natural gas to its customers.

4.5 *GROWTH CAPITAL EXPENDITURES*

Growth capital expenditures are required to attach new customers to the gas distribution system. These expenditures are for the installation of new mains, services, meters and regulators. The primary drivers of growth capital are housing starts and development activity coupled with market capture rates and to a lesser extent conversions to gas service in existing homes. The number and type of new services, mains and meters are dependent on these factors and ultimately result in customer additions.

The Conference Board of Canada (CBOC) housing start forecast in Table C4-10 below was used by the FEI Forecasting department as a basis to develop the customer additions forecast. Housing start forecasts are segregated into single family dwellings (SFD) and multi-family dwellings (MFD). In terms of new gas customers, FEI typically has a high capture rate on SFD houses and a low capture rate on the MFD starts. The housing starts table below provides a breakdown by year, by dwelling classification, together with year over growth or decline rates for each dwelling type.

Table C4-10: Conference Board of Canada Housing Starts Forecast in FEI Service Territory

	2012	2013	2014	2015	2016	2017	2018
SFD	8,142	7,854	8,415	9,027	9,213	8,974	8,663
MFD	20,213	19,186	19,586	21,915	23,260	23,291	22,649
Total	**28,355**	**27,040**	**28,000**	**30,942**	**32,473**	**32,265**	**31,312**
% Growth SFD		-4%	7%	7%	2%	-3%	-3%
% Growth MFD		-5%	2%	12%	6%	0%	-3%

The Forecasting department reviews housing start forecasts, SFD and MFD growth and capture rates and conversion markets to establish a customer additions forecast.

Table C4-11 below summarizes the NET and GROSS customer additions forecasts developed by the Forecasting group which ultimately drives both the new Services and new Meters capital expenditure forecasts.

Table C4-11: Actual and Forecasted Net and Gross Customer Additions

	2012 Actual	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Net Customer Additions	4,747	4,631	4,982	5,328	5,443	5,344	5,173
% Change		-2.4%	7.6%	6.9%	2.2%	-1.8%	-3.2%
Gross Customer Additions	8,738	8,624	8,946	9,341	9,505	9,382	9,189
% Change		-1.3%	3.7%	4.4%	1.8%	-1.3%	-2.1%

NET customer additions represents the net new additions to the customer count factoring in all new customers (new meters) added to the system as well as deducting all those that leave or have services and meters removed either by request of the customer or Company. NET number of customers equals the total number of active meters installed on the system or the number of gas bills sent out to customers.

Gross customer additions are the number of new customers in a given year associated with new service installations. For an SFD there is typically one gross customer addition (one new meter) associated with each new service line. With MFDs, where multiple meters are installed using one service line, the gross customer additions are greater than the service line installations and are equal to the number of new meters installed.

4.5.1 Growth Capital Overview

Growth capital expenditures are required for the installation of new mains, services, and meters which are necessary to attach new customers to the gas distribution system. Regulators, a smaller material component included with each meter install, are included in Meters capital. Growth capital expenditures for Mains, Services and Meters are summarized in the Tables C4-12 and C4-13 below.

Table C4-12: Historical Growth Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Mains Services & Meters Capital					
New Customer Mains	4,538	4,510	5,374	5,033	6,500
New Customer Services	13,874	14,423	17,423	16,791	12,910
New Customer Meters	1,905	1,699	1,403	1,438	2,105
	20,317	**20,632**	**24,200**	**23,262**	**21,515**

Table C4-13: Forecasted Growth Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Mains Services & Meters Capital						
New Customer Mains	6,783	5,374	5,462	5,561	5,664	5,798
New Customer Services	13,471	18,360	19,502	20,214	20,337	20,363
New Customer Meters	2,197	1,664	1,805	1,876	1,877	1,862
	22,451	**25,398**	**26,769**	**27,651**	**27,878**	**28,022**

4.5.2 Mains

Main expenditures consist of new main extensions with a number of different attributes including location, size of pipe, length of extension, pressure, type of material and installation workforce. Proposed main extension projects are evaluated through a main extension economic test (MX Test) which analyzes cost estimates for installing the main, projections in numbers of customers attached as well as forecast customer gas usage. Uneconomic results require contributions from customers for the planned main extensions to proceed.

There are two main factors used to develop the forecast mains capital expenditures: forecast mains activity levels and forecast mains unit costs.

Mains Activity Levels

Activity levels for new mains have varied considerably over the past number of years ranging from a high of 200,000 metres in 2008 to a low of 65,000 metres in 2012. In the 2012-2013 RRA Decision, the Commission stated (at page 99): "The FEU are to provide other methods for forecasting main installations in their next RRA." In response to this request, the Company has examined forecasting options and decided to depart from the past practice of estimating mains activity levels based on a three year average ratio of new mains to forecast service additions. FEI has determined that a more simple and accurate method is to forecast mains activity levels based on the most recent three-year historical average for this type of activity.

Several mains forecasting methodology options were reviewed. These options are grouped into four categories: (i) using historical level of metres of main activity, (ii) using historical ratio of new main to forecast service additions, (iii) using historical ratio of new mains to forecast gross customer additions and (iv) using historical ratios of new mains to net customer additions. The options are summarized in Table C4-14 below:

Table C4-14: Mains Activity Forecasting Options

Option #1 - 2012 actuals - **use most recent year's actuals** rounded to nearest thousand.
Option #2 - 2011-2012 actuals - 2 year average rounded to nearest thousand.
Option #3 - 2010-2012 actuals - 3 year average rounded to nearest thousand. **(NEW METHOD)**
Option #4 - 2009-2012 actuals - 4 year average rounded to nearest thousand.
Option #5 - 2006-2012 actuals - 7 year average rounded to nearest thousand
Option #6 - use 2012 **ratio of New Mains to Service Additions**
Option #7 - use 2011-2012 actuals - 2 years of New Mains to Service Additions ratio history
Option #8 - use 2010-2012 actuals - 3 years of New Mains to Service Additions ratio history **(HISTORICAL METHOD)**
Option #9 - use 2009-2012 actuals - 4 years of New Mains to Service Additions ratio history
Option #10- use 2006-2012 actuals - 7 years of New Mains to Service Additions ratio history
Option #11 - use 2012 **ratio of New Mains to Gross Customer Additions**
Option #12 - use 2011-2012 actuals - two year ratio of New Mains to Gross Customer Additions
Option #13 - use 2010-2012 actuals - three year ratio of New Mains to Gross Customer Additions
Option #14 - use 2012 **ratio of New Mains to Net Customer Additions**
Option #15 - use 2011-2012 - two year ratio of New Mains to Net Customer Additions
Option #16 - use 2010-2012 - three year ratio of New Mains to Net Customer Additions

The past practice (Option #8 above) to forecast mains activity was to use the most recent three year historical ratio of new mains to forecast service additions. The ratio was applied to the forecast service additions to derive forecast mains activity. The ratio of new mains to service additions has varied from a high of 19 metres per service in 2008 to a low of 8 metres per service in 2012 leading to parallel variability in mains forecasting.

The new method (Option #3 above) is to forecast mains activity levels based on the most recent three year historical average for this type of activity. The three year average (2010-2012) reflects the recent level of activity for new mains. The three year average rounded to the nearest thousand metres is 75,000 and was used as the forecast mains activity level for 2014-2018. Using this methodology to forecast 2012 activity was the option providing the most accurate forecast for mains activity.

Other methodology options considered were forecasting new mains based on the ratio of new mains to forecast gross customer additions (Options 11-13 above) and the ratio of new mains to forecast net customer additions (Options 14-16 above). Both methods were tested using different historical time periods (one to three year years) but yielded less accurate forecasts in predicting recent 2012 results.

The Company has changed mains forecasting methodology in an effort to improve and simplify forecasting activity levels in future years. The issue has been in finding the proper ratio or correlation of mains to customer additions given the timing difference between the main installations versus when the customer additions materialize. FEI acknowledges that there is still a longer term correlation between customer additions and mains activity, with customer additions to a new main often materializing in years subsequent to the year of the main installation depending on housing market cycles and subdivision uptake. We believe Option #3 above is an improvement to Option #8 above in determining mains activity levels.

Mains Unit Costs

Mains unit costs vary considerably by job depending on location, conditions, size, material, length of extension and workforce. The mains unit costs consist of contractor costs, IBEW labour and vehicle costs, material and planning costs. Main installations are generally completed by one of two primary installation contractors. In 2012, 80 percent of the work was completed by contractors with the remaining 20 percent completed by internal crews. Contractors are typically utilized for this type of work so that the work can be completed without interruption. Internal crews also complete this type of work where no other shorter duration work is available to them, but the work of internal crews is subject to interruptions to attend to emergencies such as hit lines or leak repairs. Internal crews do require some exposure to main installation work to be better prepared to make emergency repairs on mains.

The mains unit cost forecast uses a three year (2010-2012) weighted average unit cost adjusted for inflation as a base. Using three years of unit costs produces a larger and more representative sample size for unit costing versus relying solely on main jobs from the most recent year (2012). The three year average includes a broader selection of geographical areas, different lengths of main, variations in workforce and the other variables that impact variability in mains' unit costs.

Mains Expenditures

Tables C4-15 and C4-16 below summarize the metres of new main, the average main per metre unit cost and the resultant capital expenditures based on the following formula:

Metres of New Main x Mains per metre Unit Cost = Mains Capital Dollars

Table C4-15: Historical Mains Activities, Unit Costs & Expenditures

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Activities (meters)	81,259	79,355	65,411	75,000	109,680
Unit Costs ($/meter)	56	59	82	67	59
Expenditures (000's)	4,538	4,510	5,374	5,033	6,500

Table C4-16: Forecast Mains Activities, Unit Costs & Expenditures

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Activities (meters)	109,680	75,000	75,000	75,000	75,000	75,000
Unit Costs ($/meter)	62	72	73	74	76	77
Expenditures (000's)	6,783	5,374	5,462	5,561	5,664	5,798

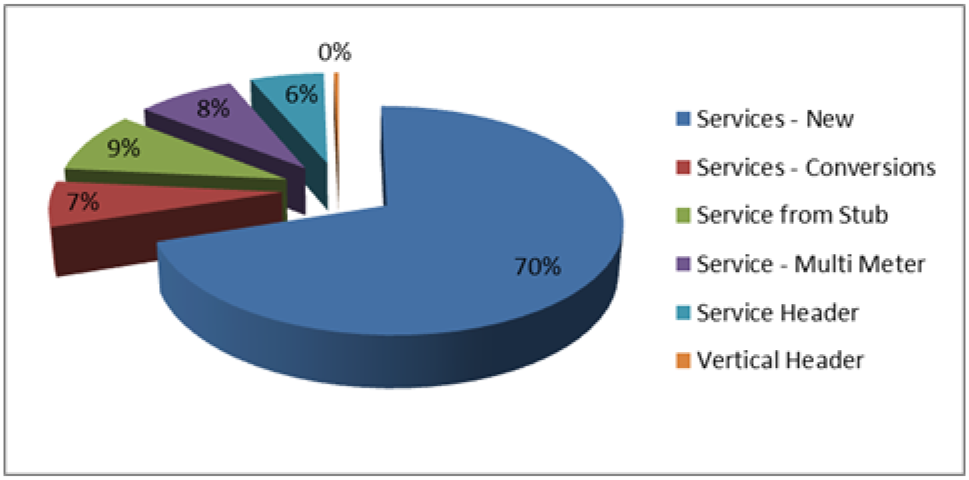
FEI believes the three year averages used to support forecast new mains volume of activity and mains unit costing is appropriate, reasonable and consistent for the purposes of demonstrating future trends in the cost of mains, given the relatively low level of activity in a single year and the wide variability between individual main jobs. If the modest inflationary scenario that has been forecast in these figures does not materialize, FEI will be challenged to manage its new mains costs within these forecast levels.

4.5.3 Services

Service expenditures consist of a variety of service types for new customers. These include new and conversion, distribution and intermediate pressure services to single and multi-family dwellings, gas stub service from the main, services installed from the stub, vertical header subdivisions (a vertical service line system within a building such as a high-rise) and distribution and intermediate new or conversion service header mains and distribution and intermediate service header laterals. Service header mains are distribution mains installed on private property (i.e. multi-family strata owned complexes). Stubs are service extensions off of the main installed with the main to eliminate road cuts and pavement repairs at a future date.

Figure C4-4 below breaks down the 2012 service activity units (each service riser) by the various service types. 71 percent of the total is “Services – New”, a standard new service. Within this service type there are many variables (short side, long side, plastic or steel, different service lengths, pressures, diameters, region, etc.). The remaining service types make up the residual 29 percent of services.

Figure C4-4: 2012 Service Activity % by Service Type



There are two basic considerations in understanding the forecast service expenditures level. These are the level of activity (number of services installed) and the aggregate blended unit cost to install the service (dollars per service). Both of these factors are discussed below.

Service Activity Levels

The 2014-2018 forecast service activity levels are derived from the gross customer additions forecast. The gross customer additions forecast is used as the driver for services activity as it reflects housing start forecasts, capture rates for the different dwelling types and expected conversions. The net customer additions is not used in forecasting new services activity levels as the net number also includes reductions in customers from removals and retirements of meters and services during the course of the year.

The forecast service additions are calculated using the 2012 actual ratio of service additions to gross customer additions of 0.90. The five year historical weighted ratio for 2008-2012 is 0.87 service additions per gross customer addition although there are year over year variations. The 2012 ratio was used as it was calculated from the most recent year of data and adequately reflects the longer term historical average.

Service Unit Costs

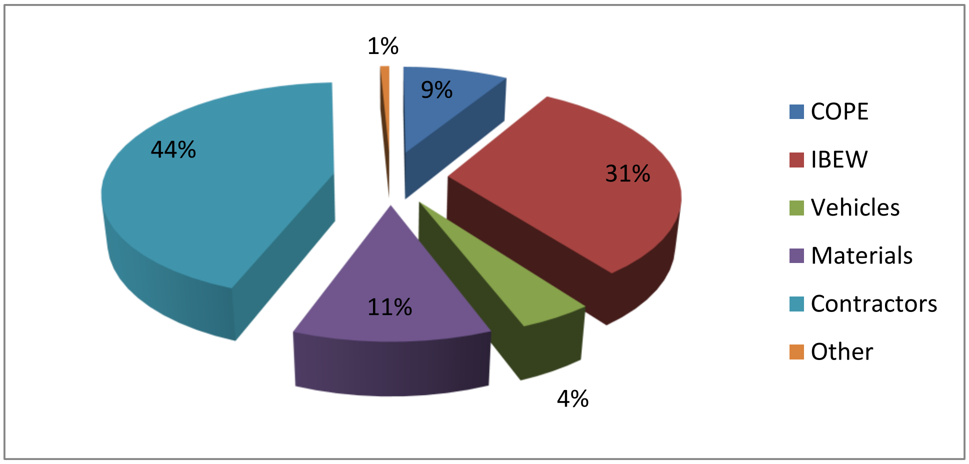
Aggregate (blended) service unit cost is the second consideration in establishing the forecast expenditures for new services. The aggregate service unit cost is calculated as follows:

Total Service Capital Dollars / Number of Services Installed = Aggregate Services Unit Cost

Service costs consist of planning and design (COPE salaries), materials and field installations (IBEW labour and vehicles, installation contractors and other contract services such as flagging, paving and gravel). Across the FEI service territory, 45 percent of the services installed in 2012 were installed by contractors.

Figure C4-5 below provides a percentage breakdown by cost element group (COPE, IBEW, contractors, materials, vehicles, and other) of the average service line unit cost in 2012.

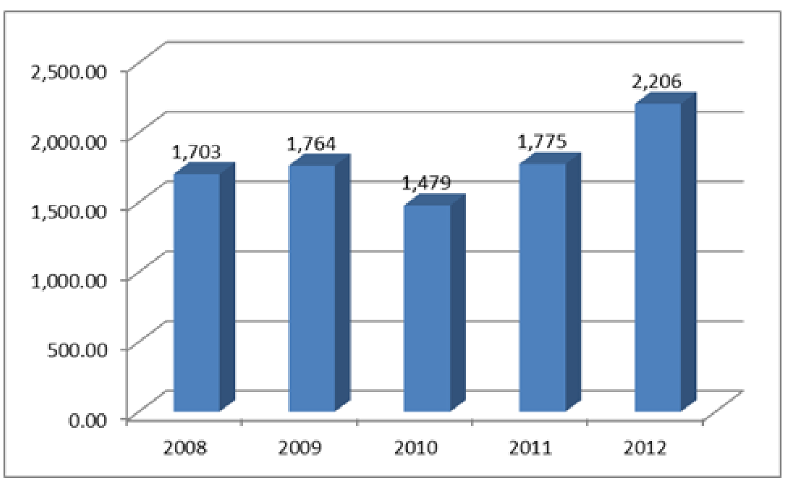
Figure C4-5: 2012 Services Unit Cost Percent (%) by Cost Element Group



The forecast services unit cost for 2014-2018 is based on 2012 actuals plus annual inflation. The forecast annual inflation rate reflects expected install contractor rates, IBEW and COPE contracts as well as materials costs. As an offset to wage / contractor inflation, there is a slight decrease due to changes in geographical distribution of forecast services.

With the exception of 2010, average aggregate services unit costs (on a per service basis) have been rising as illustrated in Figure C4-6 below. The unit costs are a reflection of the variety of service products, geographical areas of activity and workforce mix in a given year.

Figure C4-6: Average Unit Cost per Service ($) 2008-2012



There are several reasons for the trend in higher service line unit costs and most of these factors are expected to continue into the foreseeable future. The reasons can be grouped into the categories below:

1. service geographical mix
2. service product mix
3. workforce changes / inflation
4. other factors (paving, planning)

Service Geographical Mix:

The geographical mix of services installed in 2012 has changed from 2010 and this change, coupled with differences in installation costs for each municipality, has had the most upward impact on overall aggregate services unit costs.

Average installation costs in Metro region municipalities versus Fraser Valley region municipalities are typically 33 percent higher. This is due to a number of reasons including complexity of work, working in older established neighbourhoods, single sided or back lane mains, more long-side services, tie-ins to older steel mains, more paved areas and pavement cutting and repairs, traffic control requirements, traffic congestion, municipal permitting, working around substantial infrastructure, hydro-vacuum and shoring excavation requirements, contractor and pavement pricing. Fraser Valley installations are less burdened with these complexities and typically have more green-field subdivision type projects, easier tie-ins to PE main, more short side services due to double sided mains and fewer apprentices in internal crew configurations.

Service activity in the Lower Mainland has shifted from the low cost installation areas of the Fraser Valley (Surrey, Langley, Abbotsford, Chilliwack, etc.) to the higher cost installation areas in the company's Metro region (north and west of the Fraser River, in particular Vancouver, Coquitlam and Richmond). In 2010, the portion of new services in the Metro region was 29 percent and the portion of new services in the Fraser Valley was 43 percent. In 2012, these percentages are 38 percent and 35 percent respectively. The shift in the composition of the service activity to the Metro areas, Vancouver in particular, is one of the main reasons for an overall increase in aggregate service unit costs in 2012.

Service Product Mix:

There are several different service types offered across FEI, with correspondingly different associated costs. Although the dominant service product (a standard new distribution gas service) has remained at 70 percent of the total product mix, the residual third of service products has changed slightly since 2010 resulting in higher overall blended service unit costs.

Conversion services, those where customers are converting existing oil, propane, wood or electric fuel to natural gas, in 2010 made up 3 percent of the total services. With targeted conversion campaigns, the number of conversion services has increased from 5 percent in 2011 to 7 percent in 2012. Average conversion service costs are typically higher than regular new service costs due to installations taking place in well-established, paved and landscaped areas thereby putting upward pressure on overall service unit costs.

Services from stubs, another service product type, have decreased from 12 percent of the mix to 9 percent of the mix. These are typically the lowest cost installs (ranging from $993 to $1,112 per service from 2010 to 2012) and as the product proportion decreases, overall aggregate services unit costs increase.

The change in the mix of service products , together with the variability in the unit costs between the various service products, has tended to increase the overall blended service unit cost; however, prudent economic tests continue to be applied to these types of products and appropriate contributions made by customers to support the higher cost installations.

Workforce Changes / Inflation:

Service installations are completed by internal crews or installation contractors. The workforce mix for services installation work has shifted since 2010 from 36 percent contractor to 45 percent contractor in 2012. The workforce mix varies from region to region depending on internal crew availability and volume and type of work. FEI reviews its installation contracts regularly and is subject to periodic changes in contract pricing including annual inflationary adjustments.

FEI crews installed 55 percent of services in 2012. Average install hours per service for internal crews increased from 10.4 hours (2010) to 12.3 hours (2012) partly due to the inclusion of an apprentice in the crew configuration and partly due to the shift of the work activity to the typically more complex Metro municipalities. IBEW average crew wage rates (hourly charge-out rates) have risen gradually from 2008 to 2012 with wage inflation. The average crew charge-out rates are also impacted by changes to benefits, pensions and equipment charge-out rates including fuel costs.

Other Factors (Paving / Planning):

Paving costs per service rose from $103 in 2010 to $184 in 2012. The large increase from 2010 reflects the shift of service work into Metro region municipalities discussed above (more pavement cutting, more pavement repairs), as well as a general trend to greater paving requirements by all municipalities.

COPE salary costs (order taking and planning have increased on a per service basis from $109 in 2010 in 2011 to $190 in 2012. The increase reflects a shift from using standard geo-code pricing to more manual estimating for the more complex service type work (e.g., conversion services, longer services, service headers). As discussed in the FEU's 2012-2013 RRA (page

368) one of the refinements made to the estimating process was to introduce job specific estimating for conversion services as these types of installations typically attract irregular costs. The shift minimizes uneconomical attachments and ensures appropriate contributions are obtained from customers where the estimated service cost exceeds the service line cost allowance. The increase in the planning cost per service is also reflective of the increased planning requirements for work in the more complex Metro municipalities, as well as the turnover and experience levels in the planning and construction order taking departments, as well as salary inflation and step increases.

Service Unit Cost Summary:

The 2012 actual service unit costs adjusted for inflation and changes to the geographical mix of services, was used as the basis for the 2014-2018 forecast services unit cost. The 2012 cost is higher than 2010 and 2011 actuals for a combination of the reasons described above. We believe the 2012 actual unit price reflects current and future contractor pricing, current and future crew configurations and charge-out rates as well as the service product mix , the change to the geographic mix and external resource pricing for paving and flagging services.

Services Expenditures

Tables C4-17 and C4-18 summarize gross customer additions, the service additions to gross customer additions ratios, the actual and forecast service additions, the actual and forecast services unit cost and the resultant capital expenditures for services.

The services expenditures summary is based on the following calculation:

Gross Customer Additions x .90 = Service Additions (Activities)

Service Additions x Services Unit Cost = Services Capital Dollars

Table C4-17: Historical Service Activities, Unit Costs & Expenditures

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Gross Customer Additions	9,587	6,254	8,738	8,624	11,100
Ratio of Service Additions to Gross Customer Adds	0.98	1.27	0.90	0.90	0.72
Activities (riser or services)	9,382	7,958	7,898	7,762	7,989
Unit Costs ($ per service - riser)	1,479	1,775	2,206	2,163	1,616
Expenditures ($000's)	13,874	14,423	17,423	16,791	12,910

Table C4-18: Forecast Service Activities, Unit Costs & Expenditures

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Gross Customer Additions	11,100	8,946	9,341	9,505	9,382	9,189
Ratio of Service Additions to Gross Customer Adds	0.72	0.90	0.90	0.90	0.90	0.90
Activities (riser or services)	7,989	8,051	8,407	8,555	8,444	8,270
Unit Costs ($ per service - riser)	1,686	2,280	2,320	2,363	2,409	2,462
Expenditures ($000's)	13,471	18,360	19,502	20,214	20,337	20,363

FEI believes the new services activity level forecasts, based on gross customer additions forecasts, which in turn are tied to housing starts, market capture rates, and conversion forecasts are a reasonable estimation of future activity levels. The average blended service unit cost used to further develop the services capital expenditure requirement is reasonable and consistent with 2012 actuals which in turn is reflective of current internal and external installation costs as well as external services costs (i.e. paving, flagging, materials, etc.). FEI expects that the overall services unit costs will be lower in 2013 than in 2012 and the 2014 -2018 period (excluding inflation) will follow this trend due to the shift to higher proportions of activity in the Interior where installation costs are typically lower.

The forecast service expenditures are projected to increase in 2014-2018 from 2012 actuals and 2013 projection due in part to forecast growth in activity as well as inflationary pressures on all cost elements making up the service line unit cost. If the modest inflationary scenario that has been forecast in these figures does not materialize, FEI will be challenged to manage its service costs within these forecast levels.

4.5.4 New Meters

New meter expenditures are those required to purchase, fabricate and install new meters to attach new customers to the gas distribution system. New meter expenditures are forecast based on new meter activity levels and average blended meter unit costs and are summarized in Tables C4-19 and C4-20 below.

New Meters Activity Levels

New meter activity levels are the first consideration in establishing the forecast expenditure for meters. New meter activity levels are linked directly to the customer additions forecasts. The meter needs to be purchased or fabricated and subsequently installed. As services are added, so are meters; in many instances multiple meters are added with the installation of one service line. As new meters are added to the system, existing in-service meters are being removed from customer sites for various reasons and depending on type, condition and value, these meters may be added back into the meter inventory. New meter activity levels are derived from the net customer additions forecasts which recognizes new meters required for new customers as well as meters brought back into meter inventory.

New Meters Unit Costs

Aggregate or blended meter unit cost is the second consideration in establishing the forecast expenditure for meters and is calculated as follows:

$$\frac{\textit{Total Meter \& Regulator Capital Dollars (less Regulator Ever-greening Program)}}{\textit{Total Meters for Net New Customer Additions and Meter Exchanges}}$$

The meter unit cost is influenced by the type, the size, the design of the meter, the installation, fabrication and exchange conditions of the meter set and the timing of the bulk meter purchases and meter upgrade activity. A blended unit cost of all customer types is used for forecasting new meter costs, although meter unit costs typically range from $75 to $10 thousand depending on the customer requirements.

In 2012 the Meters (and Regulators) capital expenditures were 68 percent materials (primarily meters and regulators) with internal labour, both COPE (planning) and IBEW (field/meter shop) making up the residual. The average blended meter unit cost of $297 per meter in 2012 has a parallel composition.

Unit costs for 2014-2018 are primarily based on 2012 actuals and forecast inflation of 2 percent per annum. The forecast inflation rate reflects expected material (meter) cost inflation as well as IBEW & COPE labour rate increases.

New Meters Expenditures

The forecast new meters capital budget is calculated based on the following formula:

Net Customer Additions x Meters Unit Cost = New Meters Capital

New meters activity levels, new meters unit costs and capital expenditure levels are summarized in Tables C4-19 and C4-20 below.

Table C4-19: Historical Meter Activities, Unit Costs & Expenditures

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Activities (meters)	6,949	5,608	4,720	4,670	6,923
Unit Costs ($/meter)	274	303	297	308	304
Expenditures (000's)	1,905	1,699	1,403	1,438	2,105

Table C4-20: Forecast Meter Activities, Unit Costs & Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Activities (meters)	6,923	4,982	5,328	5,443	5,344	5,173
Unit Costs ($/meter)	317	334	339	345	351	360
Expenditures (000's)	2,197	1,664	1,805	1,876	1,877	1,862

2010, 2011 and 2012 actual new meter expenditures are based on the total actual net customer additions for the year multiplied by actual new meter unit costs, which is consistent with FEI's methodology for forecasting new meter expenditures for the 2014 to 2018 period. Previously-approved expenditures were based on a percentage allocation of total meter expenditures (new customer meters and meter recalls/exchanges). FEI believes that forecasting its new customer meter expenditures based on new meter activities and meter unit costs, rather than an allocation of total meter expenditures between meter recalls and new customer meters, is a more accurate and reasonable method for predicting future expenditures. As a result, the historical expenditures have been stated in Table C4-19 above to be consistent with the proposed methodology for forecast new customer expenditures.

FEI believes the new meters activity level forecasts, based on net customer additions forecasts, which in turn are tied to housing starts and market capture rates, are reasonable and that the average blended meter unit cost used to further develop the capital expenditure requirement is a reasonable and consistent method that reflects recent meter and labour pricing in an area that has a wide range of costs and customer types. If the modest inflationary scenario that has been forecast in these figures does not materialize, FEI will be challenged to manage its new meter costs within these forecast levels.

4.5.5 Growth Capital Summary

The forecasts for Growth Capital expenditures for 2014-2018 have been developed utilizing a methodology that is most indicative of current forecasted trends and based on historical data.

The Growth capital expenditures for 2014-2018 represent the level of this type of investment required to carry out its mandate to new and existing customers of FEI, given the inflation and activity levels forecast over the PBR Period.

4.6 *ALL OTHER CAPITAL EXPENDITURES*

Capital expenditures for all other plant consist of Equipment, Biomethane, Facilities and Information Technology (IT) capital. Equipment, Facilities and Biomethane expenditures include costs associated with the acquisition or leasing land; facilities including station buildings, facilities equipment; telecommunications infrastructure; specialized tools and equipment; radio system upgrades and Biomethane interconnection. IT expenditures include costs associated with information technology hardware, infrastructure and software requirements.

4.6.1 Equipment Capital Expenditures

Equipment capital expenditures include the acquisition of telecommunication infrastructure, specialized tools and equipment and radio system upgrades. In addition, beginning in 2014 vehicle purchases will be included within equipment capital instead of under a capital lease. This change was made in order to reduce the overall cost of ownership for these assets (see Section D3.1 for further discussion). Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

Equipment expenditures have been relatively consistent over the 2010 to 2013 period, averaging approximately $3 million per year. However, as stated above, this value does not include the cost of vehicle purchases (previously a capital lease addition) which is included in the 2013 Base. In addition, FEI is anticipating a step increase in 2014 of approximately $1 million, primarily due to expenditures related to the radio network. These expenditures are discussed below.

In an emergency situation, field employees are required to communicate with the entire emergency response team simultaneously using the existing radio network so the initial response and the subsequent continuation of service is undertaken in a manner that is timely, cost effective, and above all, preserves the safety of both the public and employees. In addition, FEI currently uses its radio network for SCADA data communications necessary for employees to remotely operate the distribution and transmission pipeline. Finally, the radio network is used to transmit data from the corrosion control equipment which ensure the systems that prevent corrosion within the pipeline are operating properly. However, currently the mobile radio network is operated with obsolete technology which is nearing the end of its service life. As such, the technology is no longer supported by vendors for repair service or replacement. Furthermore, although the existing technology is compliant with federal regulations with regard to frequency band width, Industry Canada has indicated its intention to transition radio network owners to operate within narrower frequency band widths to levels that would not be achievable with FEI's current technology. As such, the Company is required to replace its current technology to ensure the radio network continues to operate adequately for effective emergency communication and field operation. The planned spending is in the range of $1.1 to $1.9 million annually during the PBR Period.

4.6.2 Biomethane Capital Expenditures

Biomethane interconnection expenditures in 2013 are based on approved projects through BCUC Order G-70-13. FEI is anticipating an increase of approximately $2.8 million in 2014 compared to 2013 with a return to lower levels in the following years. These forecasts are based on known projects that have been filed with the BCUC, as discussed below.

On December 19, 2012, FEI filed its Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis with the Commission. The projected Biomethane capital expenditures in this Application assume that the Biomethane application is approved with a similar program structure to that approved in the original Biomethane Application filed in June, 2010.

The amounts for 2013 and 2014 shown in Tables C4-1 and C4-3 include approximately $2.9 million in capital already approved for three projects through BCUC Order G-70-13. If there are any impacts on the Biomethane interconnection forecasts resulting from the current Biomethane application, FEI will adjust its forecasts if applicable. FEI may also apply for approval of capital spending on upgraders for future projects in certain circumstances through a separate process.

4.6.3 Facilities

Facilities capital expenditures include the acquisition or leasing of land, buildings, and facilities furniture and equipment. FEI's Facilities capital expenditures focus primarily on upgrading and replacing existing assets. The Facilities department ensures approved facilities projects are built to meet company standards, building codes and regulations, and provide a long term solution toward meeting the business requirements.

FEI has 44 office buildings and muster sites with facilities ranging from new to 100 years in age. When it is determined that an asset is no longer adequate, FEI will decide whether to upgrade, replace or add assets depending on condition, age and capacity to provide a suitable work environment with safe and efficient building and workspaces.

Due to the timing of the 2012-13 RRA Decision combined with the long lead times required for the design, development and contracting of Facilities projects, a portion of the work scheduled for 2012 was instead undertaken in 2013. However, the combined 2012-2013 Actual expenditure will equal the combined 2012-2013 Approved amount, after adjusting for the timing of the acquisition of the North Vancouver land to support the new muster requirement, as discussed in the 2012-2013 RRA.

For 2014 to 2018, the forecasted spending in the Facilities category is consistent with historical spending which fluctuates between $3.9 million to $4.6 million based on a variety of different projects scheduled to be completed each year. Facilities will continue to support replacement and upgrade programs of HVAC, electrical, security, building envelope, building finishes and office furniture and equipment as each asset reaches the end of its service life. In addition, Facilities is planning larger projects targeted for this timeline including: (i) area generator addition to the Burnaby Operations Stores and Shops building to allow for continued operation of critical equipment during a power outage, (ii) improvements to the Horne Payne structure at Burnaby Operations built circa 1910 reflecting the increased demand for adequate storage of staged inventory associated with increased sustainment capital activity, (iii) the addition of pipe storage to the Burnaby Operations building; and (iv) three muster replacements as either the asset is near end of life or migrating from leased to owned due to real estate lease market issues.

4.6.4 IT Capital Expenditures

4.6.4.1 Information Systems Overview

FEI's Information Systems expenditures focus on enhancing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency. FEI relies on a base of core enterprise applications, including SAP (Customer Service and Billing, Financial, Human Resources, Project Management and Materials Management), SharePoint based Intranet/Internet, AM/FM (Asset and Facilities Management) and Plant Maintenance. These applications are used to support the Company's business technology requirements. FEI selected these core systems for their scalability and technology which allow them to be upgraded, enhanced and integrated thereby minimizing the need to acquire and implement new business technology solutions.

In situations where the utility is implementing infrastructure and/or applications that will benefit both gas and electric customers the Company has established a shared asset framework. The framework provides for equitable distribution of costs for assets that have a shared use and benefit from combined ownership. The allocation of asset ownership is defined through licensing and separate requisitioning for components based on usage of the shared asset by the respective organizations.

FEI's Information System's capital budget consists of the following five areas:

- Infrastructure Sustainment is the non-discretionary capital funding required to replace or upgrade outdated or end-of-life hardware and server software in the data centres. This includes servers, operating systems, LAN and WAN equipment, etc.
- Desktop Sustainment is the capital funding required to replace or upgrade end user equipment and software. This includes PCs, operating systems, desktop applications, printing equipment, etc.
- Application Sustainment is the capital funding required to sustain existing software applications. This includes required upgrades to maintain support, reliability and performance of existing applications not including data centre software.
- Business Technology Enhancement is the capital funding to modify the functionality or enable capabilities of existing applications to meet annual business requirements with priority on safety and customer service. This includes interfaces, enabling new functionality, enhanced reporting, etc.
- Business Technology Transformation is the capital funding for initiatives that impact the way business is conducted with a focus on safety and customer service. This includes the introduction of new technologies to meet business requirements, system integration that changes business processes and/or the introduction of new business processes.

Sustainment

Sustainment spending is made up of infrastructure, desktop and application sustainment capital. In an effort to achieve acceptable services levels and security for its internal and external customers, FEI puts emphasis on non-discretionary, sustainment projects. These projects typically include upgrades to existing infrastructure, databases and applications to maintain support and avoid potential productivity or reliability issues. Upgrades also ensure that new functionality and features that vendors develop through continued investment in their products are made available to end users and support staff. Ultimately these upgrades serve to extend the life and support of the asset up to or beyond its expected end of life. The 2014 to 2018 projects within the Sustainment Portfolio have been developed to fund the minimum upgrade requirements for the Infrastructure, Desktop and Application Sustainment areas described above.

Business Technology

Business technology spending is made up of both enhancement and transformation capital. The operating business units must be supported in their plans to meet customer needs, as well as gain efficiencies through system integration, optimization, and simplification. It is recognized that enhancements and transformation to business systems will be a key enabler of these changes. Enhancements to existing systems are initiated when a business requirement or opportunity arises requiring a long term solution. These enhancements do not generally include additional licenses or hardware, but do include configuration, integration and process modification to take advantage of a particular application's inherent functionality. When FEI does not possess a suitable solution able to satisfy a business requirement or opportunity, the Company will support the introduction of new business technology, process and training to meet the identified need. These initiatives are captured as transformation projects. Both enhancements to existing and the introduction of new technology require business benefits analysis and justification.

The demand for capital investment for enhancements and transformational initiatives is important particularly as the Company seeks to achieve greater efficiencies through system integration, simplification and optimization. The Company must ensure that human and capital resources are assigned to the right projects at the right time to ensure benefits and project success. This includes ensuring that competing demands from the various operating business units are supported. As such, the Company has continued the implementation of the well-established methodology known as Project Portfolio Management (PPM). PPM is a recognized discipline for managing project portfolios that facilitates the evaluation, prioritization and coordination of the requirements of the various operating business units and technologies enabling effective capital investment decisions. A benefits management practice has also been implemented as a component of PPM. A more detailed description of this and how its implementation satisfies BCUC Directive 42 from the 2012-2013 RRA Decision can be found in Appendix C4.

The following projects planned for the period of 2014 to 2018 are required to improve employee and public safety, address potential shortcomings in customer service levels and to drive O&M cost reductions. The historical and forecast capital expenditures for IT capital expenditures are summarized in Tables C4-21 and C4-22 below.

Table C4-21: Historical IT Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
IT Capital					
Businses Technology Transformation	3,655	5,099	2,193	6,300	5,850
Business Technology Enhancements	800	1,085	3,968	4,500	3,150
Infrastructure Sustainment	3,952	4,667	3,931	4,500	4,050
Desktop Infrastructure Sustainment	2,379	1,541	1,407	2,700	2,250
Application Sustainment	1,631	2,112	2,484	3,600	2,700
	12,418	14,503	13,983	21,600	18,000

While the annual approved IT budget for each of the categories above was flat through 2012 and 2013, project execution and resulting expenditures lagged in the Business Technology Transformation area, contributing to 90 percent of the $4 million underspend in 2012 against the $18 million approved spending. This lag was primarily due to the delay of the 2012-2013 RRA Decision. Factors within FEI's control have been mitigated in 2013, resulting in FEI expecting to fully execute on its 2013 IT budget. FEI plans to spend most of the unused capital from 2012 based on the Benefits Management practice implemented by FEI (see Appendix C4) within 2013, resulting in the total 2012-2013 spending being projected at approximately $1.0 million below the approved 2012-2103 total.

Table C4-22: Forecast IT Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
IT Capital						
Businses Technology Transformation	5,941	5,940	5,940	5,940	5,939	5,938
Business Technology Enhancements	3,199	3,199	3,199	3,199	3,198	3,197
Infrastructure Sustainment	3,884	3,884	3,884	3,884	3,655	3,197
Desktop Infrastructure Sustainment	1,599	1,599	1,599	1,599	1,827	2,284
Application Sustainment	5,484	5,483	5,483	5,483	5,482	5,481
	20,107	20,105	20,105	20,106	20,102	20,098

The increase of Application Sustainment capital from 2013 Approved to 2013 base by $2.8 million was discussed in Section C4.6.4.1.

Each of the five areas of forecast spending are discussed separately below.

4.6.4.2 Business Technology Transformation

As detailed in Table C4-22, FEI is forecasting annual expenditures of $5.9 million for the PBR period on business technology transformation. This area will fund any justifiable business requirement or opportunity in support of safety, customer service, reliability and productivity for FEI's operations in accordance with IT's Benefits Management practice detailed in Appendix C4.

Projects in this portfolio can include implementation of new technologies to meet business requirements, system integration that changes business processes and/or the introduction of new business processes. The objective of these projects is to change the way FEI does business in response to customer and business needs resulting in efficiencies, O&M reductions, improved customer retention and enhanced employee safety and subsequent benefits. Transformational initiatives will also support the alignment of Business Technology applications and systems between the organizations in order to drive efficiencies and improve performance for both the gas and electric businesses.

The following are examples of identified programs of work that are expected to be pursued through this Business Technology Transformation project.

- <u>Geospatial</u> – Opportunities to support asset management and the benefits of that program, which may require additional interfaces and system reconfiguration due to process changes and/or different system requirements. This will drive productivity improvements, O&M reductions and enhanced customer service.
- <u>Operation Systems</u> – An example of a component of work in this area is to assess the current electronic dispatch and field force management capabilities to ensure their optimal use. Optimization could allow the leveraging of these systems to support the electric business to the benefit of the customer. Initiatives from this program will drive productivity improvements, O&M reductions and lead to enhanced customer service.
- <u>Knowledge Management</u> – Improved access to information through structured and formalized knowledge sharing and collaboration. This program will support a knowledge based workforce to improve responsiveness and meet future business objectives.
- <u>Customer Service</u> - Take advantage of the new Customer Care Systems to enhance customer facing functionality and meet changing market needs.
- <u>Human Resources</u> – Alignment of HR systems for the gas and electric organizations, combining staff records, payroll function together with skills and competencies resulting in productivity improvements and O&M reductions.
- <u>Financial reporting</u> - Assess Finance AP Automation and Asset reporting to transform current activities through the re-engineering of accounts payable processes, improve asset management reporting, reduce audit costs and enable FEI to scale accounts payable operational activity within existing resource limits.

- Asset Management - Support asset management capabilities through the potential introduction of new technology processes.

Other transformation initiatives will be undertaken on a priority, benefit and resource availability basis. These initiatives can be driven by legislative, regulatory or business process changes that will inform their priority relative to other initiatives.

4.6.4.3 Business Technology Enhancements

As detailed in Table C4-22, FEI is forecasting annual expenditures of $3.2 million for the PBR period on business technology enhancements. This area will fund any system enhancements that are required. Enhancements to existing systems are initiated when a business requirement or opportunity arises that requires a long term solution. These enhancements do not generally include additional licenses or hardware, but do include configuration, minor integration and process modification to take advantage of a particular application's inherent functionality.

Examples of some of the expected enhancements and their drivers:

- The reporting, analysis, and interpretation of business data stored in our Business Intelligence (BI) platform is of importance to the Company in optimizing decision making. Business units are able to make well-founded decisions, predict future possibilities and determine target-orientated activities on the basis these analytics. Investments will be made in 2014 to 2018 to develop BI in support of the data requirements of the organization for reporting in customer service, operations, finance, HR and GIS data.
- Enhancements will be made to customer systems, such as the internet web site, to enhance customer self-service and information availability. Electronic billing options and capabilities will also be enhanced to broaden customer options.

Other enhancements will be undertaken on a priority, benefit and resource availability basis governed by the PPM process. Enhancements can also be driven by legislative or regulatory changes, in which case they are considered non-discretionary.

4.6.4.4 Infrastructure Sustainment

As detailed in table C4-22, FEI is forecasting annual expenditures of $3.2 to $3.9 million for the PBR Period on infrastructure sustainment. The infrastructure sustainment area includes replacing outdated or end-of-life hardware and software (operating systems and related server software) in the primary and backup data centres and supporting infrastructure (switches and routers that tie the Wide Area Network together). The life expectancy of the hardware infrastructure components is typically five years, based on industry standards and manufacturers' support, while operating systems are normally upgraded every two years to maintain vendor support. The funding is developed based on the replacement of the oldest equipment, failed equipment and minimum software upgrades to maintain manufacturer support. This strategy of asset management avoids the complete replacement of all equipment once every five years and the resource issues and work disruption that would result.

Equipment and software designated for upgrade typically include servers at end of life, disk drives that have passed maximum life expectancy, networking infrastructure replacements (failed switches, routers and hubs) and operating system and database upgrades. There is an increase in the annual requirement for 2014 through 2017 due to a number of enterprise infrastructures coming to end of life, including telephony, video conference equipment, servers, storage and backup equipment.

4.6.4.5 Desktop Infrastructure Sustainment

As detailed in Table C4-22, FEI is forecasting annual expenditures of $1.6 million for the period 2014 to 2016 in desktop infrastructure sustainment. There is an increase to $1.8 million in 2017 and $2.25 million in 2018 to support the next PC equipment and software refresh cycle. Desktop Infrastructure Sustainment includes Microsoft Windows operating system, Microsoft Office Suite and other job specific hardware and software upgrades for FEI's personal computers (PC) environment. It is a phased approach to keeping approximately 2,500 PCs current and supportable, rather than replacing all PC equipment and software every five years. The life expectancy of the desktop hardware is typically five years or less based on industry standards and manufacturers' support. The phased replacement strategy avoids the resourcing and disruption issues that occur with complete replacement of all PC equipment every five years. The Desktop Infrastructure Sustainment budget is developed based on the replacement of the oldest and failed equipment. Over the next 5 years, FEI will be moving from a bulk replacement of approximately 60 percent of the units to a more flat replacement cycle with the aim of lowering the spikes of capital investment and to level out the effort. 2018 will be the last year impacted by the bulk replacement cycle. Subsequent year's expenditures will reflect the consistent annual spend based on the flattened replacement program.

This project also includes the costs necessary to replace multi-function photocopiers/printers to maintain reliability and compatibility with industry standards. This is also a staged approach based on standard lifecycles. An asset management tool is used to track the age of all technology assets at FEI to ensure they are replaced in a timely manner and to realize maximum life expectancy without jeopardizing productivity.

4.6.4.6 Application Sustainment

As detailed in Table C4-22, FEI is forecasting annual expenditures of $5.5 million for the PBR Period in application sustainment. This area will fund the annual sustainment requirements for all FEI applications including SAP (Customer Service and Billing, Financial, Human Resources, Project Management and Materials Management modules), SharePoint, AM/FM and all other applications used at FEI. Annual upgrades maintain support and avoid potential productivity or reliability issues, as well as making new functionality and features available that the vendors have developed through continued investment in their products.

4.6.4.7 Summary of IT Capital

It is expected that 2013 IT Capital Expenditure is on target to achieve its approved budget and that most of the unused capital from 2012 will be spent within the 2013 fiscal year resulting in the 2012-2013 spending being very close to the approved total. The 2014 to 2018 forecast for IT capital is relatively flat across the categories despite expected pressures of CPI and other contractual obligations. Business Technology Transformation and Enhancements will be flat due to the anticipated lessening of demand for this type of work as several of the identified projects and programs are executed. The Sustainment categories are forecast based on asset lifecycles and expected replacements; as such, the forecasts are predictable and manageable.

4.6.5 Contributions In Aid of Construction

Tables C4-23 and C4-24 below summarizes FEI's CIAC recoveries for the historical and forecasted period.

Table C4-23: Historical Contributions In Aid of Construction ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Growth Capital	512	(1,647)	(1,860)	(1,750)	(1,373)
Sustainment Capital	(4,350)	(5,329)	(3,513)	(3,837)	(3,750)
CPCN	(84)	(834)	(250)	0	0
Retirements		(138)	(207)	(277)	(277)
	(3,922)	(7,948)	(5,830)	(5,864)	(5,400)

Table C4-24: Forecast Contributions In Aid of Construction ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Growth Capital	(1,396)	(1,777)	(1,777)	(1,777)	(1,777)	(1,776)
Sustainment Capital	(3,814)	(3,757)	(3,757)	(3,757)	(3,756)	(3,756)
CPCN	0	0	0	0	0	0
Retirements	(282)	(287)	(287)	(287)	(287)	(287)
	(5,492)	(5,821)	(5,821)	(5,821)	(5,820)	(5,819)

CIAC for the 2014 to 2018 period is based on recoveries for the forecast customer additions and anticipated receivable work.

The recoveries in this category are forecast based on the anticipated receivable work for third party alterations and historical levels of receivable work for Transmission crossing replacements and identified recoverable projects. CIAC is expected to be level during the forecast period.

4.7 CPCNs

Section 45(1) of the *Utilities Commission Act* (UCA) requires that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the Commission a CPCN approving the construction or operation. Section 46(1) of the UCA requires that an application for a CPCN be filed with Commission.

As first agreed to in FEI's 2004-2007 Multi-Year PBR Settlement Agreement, large capital expenditures over $5 million (excluding AFUDC) require a CPCN application. The 2010 Certificates of Public Convenience and Necessity Application Guidelines, issued March 18, 2010, provide general guidance regarding the Commission's expectations of the information that should be included in a CPCN application.

As CPCNs are approved through a separate process, only CPCNs that have already been approved have been included in the rate forecasts included in this Application.

The sections below discuss anticipated CPCNs, and is provided for information only.

4.7.1 Approved Projects

At this time, there are no major (estimated value exceeding $5 million) capital pipeline projects that have already been approved and will come into service during the PBR Period.

4.7.2 Anticipated Projects

Over the next five years FEI is considering a number of major projects to ensure the ongoing safety, integrity, and reliability of its gas system. Those projects will likely exceed the $5 million CPCN threshold, and therefore would be filed separately from this Application. These projects are typically identified through either integrity concerns being raised from a sustainment perspective, system improvements identified through hydraulic analyses, or through capacity concerns being raised due to demand growth as a result of specific customer additions. The following discusses those projects under consideration over the next five years for which FEI anticipates CPCNs will be required.

Cost estimates have not been updated at this time for the projects identified below, as the major pipeline projects proposed by other oil and gas companies in BC and across North America will have varying degrees of impact depending on how many of these projects actually proceed with construction and such information needs to be known with more certainty. There will be competition for both resources and materials, which will likely lead to costs being driven up for the relatively smaller pipeline projects that FEI seeks to undertake.

Huntingdon Station Bypass

FEI's Huntingdon Station is the sole source of supply to FEI's Coastal Transmission System (CTS) and the interconnected FEVI transmission system and controls gas supply to communities in the Lower Mainland, Squamish, Whistler, the Sunshine Coast, and Vancouver Island. Loss of functionality of certain sections of the Huntingdon Stationcan lead to the complete outage on both the CTS and FEVI systems, thereby triggering a potential gas supply service outage to 660,000 customers. A new station bypass at Huntingdon Station, is necessary to reduce the risk of a service outage. FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

Preload and Stabilize Remaining Right of Way between Delta Station and Tilbury Station

As a result of operational issues that have been experienced, work has been undertaken over the past several years to stabilize most of the Right of Way in the Burns Bog area through which two transmission pipelines run. There are still sections that remain to be stabilized to mitigate the risk of ground movement and associated pipe damage. FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

Coastal Transmission System Upgrade Plan

The CTS is comprised of approximately 260 kilometres of pipelines that provide natural gas transportation from the Huntingdon-Sumas trading point to various metering and regulating stations throughout the Fraser Valley and Metro Vancouver areas. It also supplies the FEVI transmission system at Eagle Mountain in Coquitlam.

Analysis of the CTS has indicated there are a number of projects that may be required in order to ensure the ongoing safety, integrity, and reliability of the system. FEI is developing an overall plan that will include those projects, and anticipates filing those projects in the form of CPCNs during the course of this PBR period. Currently, this plan includes the following projects:

1. Looping the 610mm OD Nichol to Port Mann Transmission Pipeline with 914mm OD in Surrey;
2. Looping the 610mm OD Nichol to Roebuck Transmission Pipeline with 1067mm OD in Surrey;
3. Replacing and upgrading the 508mm OD Coquitlam to Vancouver Intermediate Pressure Pipeline (the actual size and delivery pressure are still to be determined) and,
4. Looping the 508mm OD Cape Horn to Coquitlam Transmission Pipeline with 914mm OD in Coquitlam.

1. LOOP THE 610MM OD NICHOL TO PORT MANN TRANSMISSION PIPELINE WITH 914MM OD IN SURREY:

Looping the Nichol to Port Mann transmission pipeline is required to:

- Improve supply to Coquitlam Station
- Improve security of supply to 170,000 customers

- Allow redirection of pipeline flows to meet operational needs;
- Provide the ability to manage ILI operations on the pipeline and Port Mann crossing; and,
- Assist in managing the reverse flow operation of the Mt. Hayes LNG facility.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

2. LOOP THE 610MM OD NICHOL TO ROEBUCK TRANSMISSION PIPELINE WITH 1067MM OD IN SURREY:

This transmission pipeline loop is required to provide improved security for supply for up to 320,000 customers that currently depend on a single 610 mm pipeline.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period..

3. REPLACE AND UPGRADE 508MM OD COQUITLAM TO VANCOUVER INTERMEDIATE PRESSURE PIPELINE:

Replacement of this pipeline is required to mitigate risks to identified corrosion and ensure security of supply to up to 41,000 customers.

FEI anticipates filing a CPCNfor this project and completing this project during the PBR period..

4. LOOP THE 508MM OD CAPE HORN TO COQUITLAM TRANSMISSION PIPELINE WITH 914M OD IN COQUITLAM:

This pipeline loop is required to enable improved supply through Coquitlam station and to provide improved security of supply to up to 150,000 customers.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

Kingsvale-Oliver Reinforcement Project (KORP)

The KORP consists primarily of a 161 km, 24-inch expansion project from Kingsvale to Oliver, BC. The reinforcement would further integrate and expand service using available capacity on T-South and SCP. The KORP provides an opportunity to deliver a growing supply of British Columbia gas to the Pacific Northwest and California markets. Removing pipeline capacity constraints would build on the T-South Enhanced Service offering for FEI customers, including additional demand charge revenue, T-South toll savings, and improved access to competitively prices and reliable gas supply, as well as additional security of supply and liquidity in the region. FEI customers have received accumulated financial benefits of $25 million from the T-South Enhanced Service offering. This is forecasted to grow to $36 million by 2014. The T-South Enhanced Service has provided shippers with the optionality of delivering to Sumas or the Kingsgate market. Expansion of the bi-directional Southern Crossing system would also aid in increasing capacity at Sumas during peak demand periods. FEI continues to assess this project, and depending on commercial commitments from shippers, may file a CPCN for this project during the PBR period.

4.7.3 CPCN Summary

As discussed above, these anticipated CPCN projects are included for informational purposes only, as each will be approved through a separate process. FEI will be filing applications with the Commission to review the necessity of these projects to provide ongoing safe, reliable and economically efficient service to its customers.

4.8 *SUMMARY OF CAPITAL EXPENDITURES*

The forecast 2014 - 2018 capital forecasts provide a high level view of the projects and spending priorities of FEI over the PBR Period. These forecasts are provided for reference purposes, as the formula-driven capital expenditures amounts are included in the 2014 rates being set through this Application, and reflect the methodology to be applied throughout the PBR Period.

D: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

This section addresses the Company's financing activities and requirements, taxes, changes in the accounting policies and procedures followed by the Company, and deferral accounts and amortization periods.

1. FINANCING AND RETURN ON EQUITY

The Company finances its approximately $2.8 billion investment in rate base assets with a mix of debt and equity, as approved by the Commission from time to time. Subject to Commission Order G-75-13, the Commission has approved a capital structure of 61.5 percent debt and 38.5 percent equity with an allowed Return on Equity (ROE) of 8.75 percent, effective January 1, 2013. In this Application, FEI has forecast debt and equity financing costs for 2014 through 2018. The 2015 through 2018 forecasted amounts demonstrate the expected trends over the PBR Period and will be updated as part of FEI's Annual Reviews. The equity costs are subject to separate processes and rates will be amended accordingly to reflect those determinations.

1.1 *FINANCING COSTS*

Debt financing costs include the interest expense on issued debt as well as interest expense on new issuances that are forecast. Debt consists of both Long-term Debt and Short-term (Unfunded) Debt.

1.1.1 Long-term Debt

FEI is a public issuer of long-term debt. FEI has long-term debt issues maturing in each of 2015 and 2016 of $75 million and $200 million, respectively. FEI expects to refinance these two issues with debentures in both years and has reflected this in its forecasts, as described below:

- The $75 million issue is the refinancing of FEI's Series A Purchase Money Mortgage, shown in the long term debt schedules as net proceeds of $74.250 million after reduction for issuance costs.
- The $200 million issue is the refinancing of FEI's Series B Purchase Money Mortgage, shown in the long term debt schedules, of which approximately $166 million is allocated as regulated debt.

Additionally, FEI is forecasting a long term debt issue in 2017 of $200 million of which net proceeds are $198.5 million (after reduction for issuance costs).

The long term debt issuances described above are FEI's current forecasts at this time and may change in both amount and timing based on FEI's on-going financing requirements. Any changes will be reflected in FEI's Annual Reviews during the PBR Period.

1.1.2 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 $500 million committed credit facility that currently matures August 2014. On May 30, 2013, FEI applied for approval from the Commission to extend the maturity date to August 2015[62]. The credit facility provides FEI with required liquidity should there be constraints issuing commercial paper used to fund working capital and/or issuing long-term debt used to fund capital spending.

1.1.3 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. No long term debt is forecast to be issued in 2014, as such the current embedded cost of long term debt is unchanged from 2013. The estimated issue rate for the forecasted 2015, 2016 and 2017 issues are shown below in Table D1-1. These rates will be updated in FEI's 2014 through 2016 Annual Reviews.

Table D1-1: Long Term Debt Interest Rate Forecasts

	2015	2016	2017
30 YR GOC	3.75%	4.00%	4.00%
Indicative Spread	1.40%	1.40%	1.40%
New Issue Rate	**5.15%**	**5.40%**	**5.40%**

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

[62] Order G-49-06 approved the $500 million credit facility. Extension Orders: G-96-07, G-90-08, G-78-12

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 approximately 1.2 percent in 2014 to approximately 3.5 percent by 2017. The short-term borrowing rate forecasts are shown in Table D1-2 below. These forecasts will be updated annually as part of the Company's Annual Reviews.

Table D1-2: Short Term Interest Rate Forecasts

	2014	2015	2016	2017	2018
3-month T-BILLS	1.17%	2.03%	2.80%	3.10%	3.48%
Spread to CDOR	0.27%	0.27%	0.27%	0.27%	0.27%
CDOR	1.44%	2.30%	3.07%	3.37%	3.75%
Spread to CP	-0.22%	-0.22%	-0.22%	-0.22%	-0.22%
CP Dealer Comission	0.10%	0.10%	0.10%	0.10%	0.10%
Standby Fee on undrawn Credit[1]	0.48%	0.38%	0.32%	0.48%	1.06%
FEI Short-term Rate (Rounded)	**1.75%**	**2.50%**	**3.25%**	**3.75%**	**4.75%**

NOTE: (1) Amounts undrawn on the credit facility are subject to a Standby Fee, which is estimated to be 16 bps in 2014 and beyond. The Standby Fee as shown reflects the amount payable had it been converted to a rate applied to the Commercial Paper borrowings and has been shown as such to develop an all-in Short-Term Rate.

1.1.4 Interest Expense Forecast

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

The calculation for 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 2014 long-term debt schedule for FEI can be found in Section E, Schedule 62.

The 2014 forecast of interest expense is $1.5 million lower than 2013 approved. The change is due to a decrease in interest rates offset by additional interest costs due to a higher portion of rate base financed through debt as a result of the updated capital structure described in Section D1.2 below.

Due to the uncontrollable nature and forecasting uncertainty associated with interest rates, FEI has an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances and variances in the timing of long-term debt issues, as compared to forecast.

1.2 ALLOWED CAPITAL STRUCTURE AND RETURN ON EQUITY

Based on Commission Order G-75-13, FEI has updated this Application with the approved equity thickness of 38.5 percent and an allowed ROE of 8.75 percent. Order G-75-13 has set the capital structure through to December 31, 2015 and has set the allowed ROE at 8.75 percent through to December 31, 2015, subject to any changes as a result of the reinstatement of an Automatic Adjustment Mechanism (AAM) to determine the approved ROE in years 2014 and 2015. The results of the AAM, if any, for 2014 and 2015 will be incorporated in FEI's 2014 and 2015 rate forecasts through an evidentiary update (for 2014) or through the Annual Review (for 2015). As part of Order G-75-13, the Commission has 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. The outcome of such a proceeding will be reflected in rates once determined.

1.3 SUMMARY OF FINANCING AND RETURN ON EQUITY

FEI continues to prudently manage its capital structure and address financing requirements in an appropriate manner. The timing and amount of debt issuance supports the rate base requirements of FEI during the term of the PBR, and the forecasted debt rates represent reasonable estimates based on market information. FEI maintains adequate credit to provide sufficient liquidity to meet its ongoing working capital requirements and address any concerns that may result from tighter credit markets.

2. TAXES

In carrying out its mandate as a gas service provider, FEI incurs taxes that are imposed by different government bodies. The Company manages these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current enacted tax legislation which was applied in calculating the forecasted revenue requirement for the Company.

2.1 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating the Company's revenue requirements. 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 25 percent for 2014. For the purposes of the forecasts in this Application, FEI has used the same corporate tax rate forecast for 2015 through 2018. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and will be updated each year as part of the annual rate setting process.

In its 2013 Budget, the BC government announced its intention to increase the general corporate income tax rate by 1 percent, effective April 1, 2013, however this rate increase was not enacted prior to the May election. A final decision regarding changes to the BC corporate tax rate and the effective date will be made by the new government. Should a new tax rate be enacted prior to customer rates being approved, the Company will recalculate taxes accordingly. If a new tax rate is not enacted prior to customer rates being set, the increase in corporate taxes will be calculated and captured in the Tax Variance deferral account once the change in the income tax rate is enacted.

As approved by Commission Order G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

2.2 *PROPERTY TAX*

Details of 2012 property tax expense and the forecasts for 2013 through 2018 can be found in Table D2-1 below.

Over the period 2014 to 2018, property taxes are forecast to increase between 1.1 percent and 2.6 percent per year, primarily due to changes in revenues from gas expected to be consumed within municipalities, increases to assessed property values from normal construction activities, market value increases and changes in tax policies of local taxing authorities.

Table D2-1: Property Tax Expense

Asset Type	Actual 2012	Approved 2013	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Distribution Assets	$ 16,908.1	$ 18,842.8	$ 17,357.4	$ 18,178.2	$ 18,737.5	$ 19,415.5	$ 19,896.7	$ 20,450.8
Transmission Assets	13,553.9	14,485.9	14,097.9	14,501.3	15,043.8	15,605.8	16,076.3	16,574.2
Gas Storage Assets	924.6	1,033.9	937.7	927.6	951.1	964.4	971.4	980.2
Manufactured Gas Assets	25.2	28.3	28.0	28.4	28.8	29.2	29.5	29.8
General Assets	2,720.3	2,935.3	2,940.8	2,944.5	3,006.5	3,069.7	3,115.9	3,168.0
In-Lieu	13,100.5	13,727.8	12,542.2	12,031.9	11,382.7	11,344.6	11,323.4	11,303.5
OGC Fees	182.5	185.0	185.0	185.0	185.0	185.0	185.0	185.0
Total Property Taxes	$ 47,415.1	$ 51,239.0	$ 48,089.0	$ 48,796.8	$ 49,335.2	$ 50,614.1	$ 51,598.2	$ 52,691.5
Forecast Change ($000)				707.84	538.42	1,278.87	984.09	1,093.29
Forecast Percentage Change				1.5%	1.1%	2.6%	1.9%	2.1%

2.2.1 Property Tax Forecasts

Property taxes for 2014 to 2018 use Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from gas consumed within municipalities. Consistent with past practice, variances between the property tax amounts forecast in rates and actual amounts paid are captured in the Property Tax Variance account and returned to or recovered from customers over the following three years.

2.2.2 Assessment Policy

Assessment policy is set out in Provincial legislation under the Assessment Act and is primarily concerned with valuation principles and methodologies as well as classification of properties for taxation purposes. Valuations of utility properties are highly dependent on legislated manuals and rates to determine market values.

FEI is required to report assessable additions annually to BC Assessment.

Property assessment values for the current tax year reflect the market value at July 1 of the previous year based on the state and condition of the property at October 31 of that year.

2.2.3 Tax Policy

Tax policy is applied by various taxing authorities under their legislated authority and determines how their budgets will be distributed to various classes of properties through the property tax. Property tax payable by FEI is categorized into four (4) general categories of taxes as follows:

1. General Taxes: These are typically levied directly by the primary taxation authority and include municipalities, First Nations and the Surveyor of Taxes for rural areas.
2. School Taxes: These are levied directly by the Province.
3. Other Taxes: These include all taxes levied by other taxation authorities and include levies for BC Assessment, Municipal Finance Authority, Regional Districts, Hospital Districts, Translink, etc.

4. Taxes based on Revenues: Section 353 of the Local Government Act and Section 398 of the Vancouver Charter require “utility companies” to pay a portion (1.25 percent in Vancouver and 1.0 percent for all other municipalities) of revenues in lieu of taxes that would otherwise be paid on improvements specified in legislation other than buildings. For FEI, revenues only include those earned from gas consumed within the specific municipality.

2.3 *CARBON TAX*

The Carbon Tax represents a cost to the Company on its own consumption of fuel to operate compressors, line heaters, motor vehicles and space heating. The Carbon Tax rate applicable to natural gas since July 1, 2012 is $1.50 per GJ. There are no further announced increases beyond this date. The estimated cost to FEI with respect to Carbon Tax on own-use fuel is embedded in O&M and capital. Any unforecast changes in the Carbon Tax rate during the PBR Period will be assessed and reflected in the Tax Variance Deferral Account.

2.4 *PROVINCIAL SALES TAX AND GOODS AND SERVICES TAX*

Effective April 1, 2013, the Province of BC has returned to a commodity tax regime of BC Provincial Sales Tax (PST) and federal Goods and Services Tax (GST). The PST is a tax of 7 percent on purchases of tangible property and certain services that the Company uses in its operations.

PST paid by FEI is not recoverable from the government and therefore represents a net cost to the Company, which can vary widely based on the level of purchases and capital expenditures. This cost is embedded in capital and O&M depending on the nature of the property or services acquired.

The GST is a federal commodity tax exigible on goods and services at a rate of 5 percent. FEI, as a GST registrant, is entitled to recover virtually all of the GST it pays on its taxable purchases of goods and services from the government. As such, the tax does not represent a net cost to the Company.

2.5 *MOTOR FUEL TAX (MFT) AND INNOVATIVE CLEAN ENERGY (ICE) LEVY*

The Province levies other taxes on various goods and services. These taxes include the MFT, which applies at a rate of 1.9 cents per 810.32 litres of natural gas used in compressors. The ICE Levy of 0.4 percent on purchases of energy, including natural gas, was reinstated effective April 1, 2013. The MFT and ICE Levy are not recoverable from the government and therefore represent a net cost to the Company. Forecasts of these amounts are included in the Company’s cost of service.

2.6 TAX ISSUES

2.6.1 Risk of Changes in Tax Laws or Accepted Assessing Practices

At any time, FEI can face changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Federal or Provincial sales taxes or any other tax that may be imposed. As discussed in Section D4, FEI will continue the approved deferral account treatment to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies, at Federal, Provincial, Municipal or any other level of jurisdiction.

2.6.2 PST incurred in 2013

With the re-introduction of PST as of April 1, 2013, as described in Section D,2.4 above, FEI has included an addition to the Tax Variance deferral account in 2013 to recognize the resulting revenue requirement impacts and implementation costs for the transition back to PST. This treatment was discussed in the 2012-2013 RRA[63] where the FEU indicated that, if the HST was repealed, the impacts on revenue requirements, including any associated implementation costs, will be assessed and reflected in their respective Tax Variance deferral accounts. The methodologies used to calculate the impacts are the same as those that were used in 2010 when HST was implemented in the Province. A full description of the methodologies can be found in the Sept. 27, 2010 Application to the Commission for the HST impacts on the 2010-2011 RRA provided as Appendix F7 in this Application.

As shown in Table D2-2 below, FEI has included $1.141 million as an addition to the deferral account in 2013, of which $743 thousand is related to the revenue requirement impact of the implementation of PST[64], and a further $398 thousand is related to the system changes required to implement the return to PST.

Table D2-2: 2013 PST impacts included in Tax Variance deferral

Summary of PST Analysis	($000)
2013 Estimate - Revenue Requirement Impact of PST	$ 743
Internal Labour/Salaries	$ 216
Consulting	$ 302
Admin Costs	$ 13
Tax on above items	$ (133)
Total Costs of Implementing PST net of tax	$ 398
Total to be Collected from Customers	**$ 1,141**

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[64] Appendix F7

2.7 SUMMARY OF TAXES

FEI will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies. The Company manages these expenditures through ongoing compliance activities, as well as through the tax audit process and various tax planning strategies. The tax expenses included in this Application reflect the current enacted tax legislation that has been applied in calculating the PBR Period forecasts for FEI.

3. ACCOUNTING POLICIES

This section describes the Company's current and anticipated accounting policies over the PBR Period, as well as addressing a number of other accounting-related changes and responses to accounting-related Commission directives from the 2012-2013 RRA.

3.1 *GENERALLY ACCEPTED ACCOUNTING PRINCIPLES*

This Application has been prepared using accounting policies and estimates assuming the continued use of United States Generally Accepted Accounting Principles (US GAAP). Commission Order G-117-11 approved the FEU's request to adopt US GAAP, as opposed to International Financial Reporting Standards (IFRS), for regulatory accounting purposes for the period from January 1, 2012 to December 31, 2014. The FEU will be applying to the Commission in 2014 for approval to continue to use US GAAP compliant policies for regulatory purposes beyond 2014.

Currently, FEI has an exemption from the Ontario Securities Commission (OSC) which allows it to prepare its external financial statements in accordance with US GAAP without qualifying as a United States Securities and Exchange Commission (SEC) Issuer. The exemption was received in 2011 and covers the period beginning January 1, 2012 and ending December 31, 2014. FEI intends to continue using US GAAP for external financial reporting purposes beyond 2014 by either obtaining an additional OSC exemption or by becoming an SEC Issuer. FEI, as part of the Fortis Group, intends to file a request by December 31, 2013, that the OSC extend the exemption beyond 2014. If the OSC does not agree to an extension then FEI, as part of the Fortis Group, will begin the process of becoming an SEC Issuer in order to continue preparing external financial statements in accordance with US GAAP for 2015 and beyond.

In early 2013, the International Accounting Standards Board (IASB) re-initiated a project on rate-regulated accounting under IFRS. The IASB expects to publish a discussion paper in the fourth quarter of 2013 as the first step in this renewed project to determine whether, and if so how, IFRS should be amended to reflect rate regulation. It will remain unclear whether or when regulatory deferral accounts can be recognized under IFRS until this comprehensive project is completed, which is likely to take several years. In the meantime, in April 2013 the IASB issued an Exposure Draft of an interim standard that would provide temporary guidance and allow first-time adopters of IFRS to continue applying rate-regulated accounting as permitted under their previous GAAP accounting policies until the larger, comprehensive project is completed. Entities that already apply IFRS would not be permitted to avail themselves of this interim standard.

In light of the IASB's renewed activity on rate-regulation, the Accounting Standards Board of Canada (AcSB) has extended the mandatory IFRS adoption date for qualifying rate-regulated entities to January 1, 2015, based on the assumption that the final interim standard on rate regulated activities will be published by the IASB by the end of 2013. This is the fourth extension provided by the AcSB to qualifying rate-regulated entities in Canada since the initial mandatory IFRS adoption date of January 1, 2011 was announced. Previous extensions were provided in October 2010 (extended adoption date to January 1, 2012), May 2012 (extended adoption date to January 1, 2013), and October 2012 (extended adoption date to January 1, 2014). Each of these extensions was provided due to continued changes in IASB activities related to a possible solution for accounting for rate-regulated activities under IFRS. Despite the level of activity in IASB discussions, no formal guidance has been published. The lack of timeliness of the IFRS extension announcements and the inability to finalize a rate-regulated accounting standard has created significant uncertainly for rate-regulated utilities like FEI, many of whom are now using US GAAP as a more appropriate alternative. Due to the continued uncertainty around the future of accounting for rate-regulated activities under IFRS, and other accounting and financial reporting inconsistencies between IFRS versus US GAAP, FEI plans to continue to use US GAAP as its basis for both regulatory and external financial reporting in 2014 and beyond despite the IASB's renewed interest in rate-regulated accounting. To consider adopting IFRS in 2015 or beyond would result in an additional one-time cost to implement. And, given the uncertainty around the project undertaken by the IASB, the future effects of adopting IFRS remain unknown at this point. On the other hand, accounting for rate-regulated activities under US GAAP has been in place for decades. Continuing to use US GAAP in 2014 and beyond would avoid the one-time project costs referred to above and avoid any uncertainty in accounting for rate-regulated activities under US GAAP which is known and well established.

In Order G-117-11 the BCUC approved the adoption of US GAAP by FEI for regulatory accounting and reporting purposes effective January 1, 2012. As part of that order, the Commission requested an annual reconciliation from US GAAP back to Canadian GAAP. FEI has provided this reconciliation in the 2012 BCUC Annual Report Tab 17. This reconciliation provides a link back to Canadian GAAP which existed prior to 2012. However, FEI no longer maintains specific accounting records in compliance with pre-2012 Canadian GAAP since they are not used for any other reporting purpose. It will therefore become increasingly complicated to complete this reconciliation on a prospective basis. Further, the effects of US GAAP for regulatory accounting and reporting, which related to pension and other post-employment benefits, are now embedded and transparent within the Application as reflected in Section D4 Deferrals. Given these developments, FEI does not see any need to continue with the reconciliation and believes that the US GAAP accounting changes for FEI should be treated the same as any other accounting policy change that has been previously implemented and communicated in previous applications. For these reasons, FEI is requesting, as part of this Application, to discontinue this US GAAP to Canadian GAAP reconciliation starting with the 2013 BCUC Annual Report.

Three accounting-related changes, which are not specifically related to adopting US GAAP, have been implemented starting in 2014, as part of this Application. They are related to the allocation of retiree pension and OPEBs, the capitalization of annual software costs, and the purchase of vehicles. For purposes of the formula-driven O&M and capital, the 2013 Base to which the formula is applied has been adjusted for these three items.

Allocation of Retiree Pension and OPEBs

In 2010, FEI separated the current service portion and retiree portion of both pension and OPEB expenses. This change was made in anticipation of the adoption of IFRS which allowed for the capitalization of only direct expenditures into benefits loadings and capital. As a result of the adoption of US GAAP starting January 1, 2012 and the plan to continue using US GAAP as the basis of financial and regulatory accounting during the PBR Period, FEI is requesting to include both the current service and retiree portion of pension and OPEBs in benefit loadings, consistent with the practice prior to 2010. For the 2013 Base, this has the impact of shifting $930 thousand from O&M to capital.

Capitalization of Annual Software Costs

FEI is proposing to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability. The costs capitalized reflect estimates of the portion of these costs that relate to the upgrade capability versus the support and maintenance components. The costs allocated to capital using this methodology are to fund only the upgrade component of the annual costs which extend the life of the affected software assets. Annual software costs in regards to support and maintenance continue to be an operating expense. The impact of this capitalization methodology is the reduction of FEI 2013 Base O&M by $1.8 million and an increase of capital within the Application Sustainment sub-Portfolio by the same amount.

Purchases of Vehicles

Currently, FEI acquires the majority of its fleet from a 3rd party lessor, whereas, the other utilities (FEVI, FEW and FBC) purchase their vehicles. A consistent treatment of how vehicles are acquired would simplify business processes within the Fleet and other support departments. Purchasing vehicles would also ensure that FEI is not exposed to risks associated with the credit markets as was experienced in 2009 during the credit crisis.

FEI completed an analysis on its current fleet of vehicles, with the review intended to ascertain whether FEI should continue to lease its vehicle fleet or transition to an owned fleet. FEI's analysis indicates that FEI should transition the vehicle fleet to an owned status as the current leased vehicles are retired. This option has the lowest present value cost of service (approximately $3 million over a 20 year analysis period), and therefore a lower rate impact to customers. To facilitate the transition, as existing leased units are retired; they will be replaced by units that are purchased.

FEI notes that this decision to purchase vehicles does not change the regulatory treatment. Since the existing vehicle lease is treated as a capital lease for financial and regulatory purposes, the change only results in what was previously shown as a capital addition now being shown as a capital expenditure (an actual cash outlay) in the financial schedules. The vehicles that are being purchased are estimated to have an average 8 year service life, resulting in a depreciation rate of 12.5 percent for this asset class (484).

3.2 CASH WORKING CAPITAL

The cash working capital requirements that have been included in the PBR Period reflect the most recent Lead Lag Study results, included in the 2012-2013 RRA and approved through Commission Order G-44-12, and represent the amounts required to compensate FEI for the timing differences between when expenditures are required to provide service and when collections are received for that service.

As a result of the re-introduction of PST and GST effective April 1, 2013, FEI has removed the HST and Residential Energy Credit lead days from the cash working capital calculation effective 2014 and updated them to show the PST and GST lead days as shown in Table D3-1 below. The PST and GST lead days are the same ones that were approved in Commission Order G-141-09 prior to the introduction of the HST. The modification of the lead days to reflect PST and GST does not materially impact the cash working capital or the cost of service for FEI and results in a minor increase to the cash working capital because of the lower input tax credit associated with gas purchases and non-labour O&M.

Table D3-1: The Re-introduction of PST and GST Results in a Minor Change to Cash Working Capital

	Approved HST Lead Days	Approved REC Lead Days	Proposed PST Lead Days	Proposed GST Lead Days
FEI	38.8	33.8	37.1	38.8

Consistent with the treatment of HST, GST is remitted to the Government of Canada at the end of the subsequent month. Therefore, the currently approved lead day associated with HST is applicable when determining the working capital implications of the GST.

As discussed in Section D2, with the elimination of the HST, the GST, PST and the ICE Levy were re-introduced. The impact of the ICE Levy is embedded in the lead day determined for PST. Therefore, the HST and Residential Energy Credit lead days are no longer applicable to the determination of cash working capital and must be removed.

FEI requests approval to modify its approved Lead Lag days with the removal of the HST and Residential Energy Credit lead days and the insertion of the proposed PST and GST lead days, as set out in Table D3-1.

3.3 *DEPRECIATION RATES AND METHODOLOGY*

The depreciation expense calculated for 2014 reflects the depreciation rates approved as part of the 2012-2013 RRA through Commission Order G-44-12. In the 2012-2013 RRA Decision, the Commission made the following recommendation on page 81:

> *"In the design of any future PBR mechanism, the Commission Panel recommends that the parties take into account the potential impact of asset usage and deprecation."*

This recommendation has been addressed in two ways. First of all, consistent with the recommended approach to update depreciation rates every 3 to 5 years, FEI will provide an updated depreciation study during the term of the PBR Period and anticipates that, subject to Commission approval, any updated depreciation rates would be implemented during the term of the PBR. This will address concerns from the 2004 Plan regarding asset losses that accumulated as a result of the approved depreciation rates being lower than the asset lives for the duration of the previous PBR period. Second, FEI will continue to update its estimate of asset losses on an annual basis throughout the PBR Period for review by the Commission.

Also in this PBR Period, FEI proposes to return to the method of calculating depreciation expense that was approved as part of the 2004-2007 PBR (extended for 2008 and 2009), whereby depreciation expense commences at the beginning of the year following when the asset is placed into service (as compared to the current practice of depreciation commencing at the time the asset is placed into service). This will allow FEI to discontinue the use of the Depreciation deferral account, as described further in Section D4.

3.4 *NEGATIVE SALVAGE*

In the PBR Period, FEI will continue with the currently approved method of calculating negative salvage. This method was directed by the Commission in its 2012-2013 RRA Decision on page 85 (also Directive No. 34, Appendix A, page 6) as follows:

> *"The Commission Panel directs the FEU to continue forecasting salvage costs in each test period and to include this estimate in future revenue requirements applications. Actual results of the past test period should be included in these applications.*
> *In addition, the FEU are directed to provide annual reports to the Commission, of total accumulations, by asset class, of the following:*
>
> *i) total salvage provision for the period,*
> *ii) total salvage expenditures,*
> *iii) a description of the total value of the asset rate base retired by asset class,*
> *iv) descriptions of the most common methods of retirement used during the period,*
> *v) the annual and cumulative to date (starting in 2012) actual cost to salvage assets, as a percentage of the actual rate base value of the assets retired, and a comparison of how that rate compares to the rate recommended in the prior depreciation study,*

vi) *a general description of any major trends or retirements that have occurred in the year (i.e. a specific type of pipe or type of meter that required a significant retirement), and*

vii) *an update of trends, any alternative retirement methodologies not being used by the FEU and the future outlook of retirement procedures for each asset class including a description of how any changes in methodologies or available technologies could affect retirement costs."*

In accordance with Directive 34, FEI has included items (i) through (iii), item (v), and item (vi) as it relates to 2012, in Tab 19 of its 2012 BCUC Annual Report as directed. Item (iv) is addressed below; these methods of retirement used do not vary by year and are expected to be unchanged for the entire PBR Period and were therefore not appropriate to be included in the BCUC Annual Report. Item (vi) (a discussion of major retirements for 2013 and 2014) is included in Section D3.5.1 below. Item vii), being a future-looking request, also did not fit within the BCUC Annual Report and is instead addressed below.

Item (iv) Description of the Most Common Methods of Retirement Used

FEI has interpreted the reference to "methods of retirement" as referring to the procedures followed in the field to remove assets from service. Additionally, it has been interpreted to include only those asset classes (44X LNG, 46X Transmission and 47X Distribution) which are expected to have negative salvage expenditures and for which negative salvage rates were approved in the 2012-2013 RRA.

For 44X LNG and 46X Transmission, the retirement procedure is to remove the assets from service, recognizing applicable environmental and safety requirements. LNG assets, like most plant specific assets (e.g. compressor stations), have never been abandoned at the plant level. Equipment that has become obsolete or unserviceable is replaced as required. Transmission pipelines are abandoned using the same methodology as Distribution mains (see below) where the assets are left in place wherever practical and sectionalized.

For 47X Distribution Plant assets, retirements are mostly for services, mains and meters.

For 473 Distribution Plant Services, the Company's abandonment procedure is to disconnect at the service tee (i.e. cut-off at the connection to the mains), leaving the service line in the ground. All sections of service line left in the ground must be purged and plugged to prevent migration of gas or water along the pipe. Where required for safety reasons, FEI has a service retirement program to remove the service line.

For 475 Distribution Plant Mains, the retirement procedure is to permanently disconnect the main from the gas source using appropriate stop-off procedures. The abandoned pipe must be sectioned into lengths of 200 metres or less, and all open ends must be plugged or sealed with watertight closures in order to minimize potential gas or water migration.

For 478 Distribution Plant Meters, the retirement procedure for the majority of its meter population (i.e. residential) is to scrap the meters and the components on exchange instead of refurbishing them, as the cost to refurbish residential meters has become uneconomical as the cost of a new meter has declined over time.

Item (vii) Future Outlook and Changes in Procedures for Retirement

FEI retirement procedures for the assets as discussed above are consistent with that utilized in industry and have been used by FEI for many years. In retiring assets, FEI focuses on ensuring compliance with safety and environmental regulations while incurring the lowest reasonable costs. Future changes in safety and environmental requirements may affect retirement costs. For example, potential future environmental requirements in some jurisdictions would require FEI to flush out abandoned pipe and fill with slurry, which would increase the costs of retirement. Currently, there is no such requirement.

3.5 ASSET LOSSES

The discussion in this section is provided in response to the following Recommendation and Directives in the 2012-2013 RRA Decision related to asset losses.

3.5.1 Directive re Assets Not In Use

The Commission included the following directive on page 71 of the 2012-2013 RRA Decision (Directive No. 35, Appendix A, page 6):

> *"The Commission Panel directs the Utilities in the future to fully and transparently disclose the nature and amount of all assets or amounts included in their plant in service account that are being depreciated into rates but are not in use, or are not expected to be in use in the test periods, whether due to retirement or for other reasons."*

FEI has a reliable fixed asset accounting process to adequately account for its assets including accounting for retirement of assets not in use. Retirements of distribution mains and services and meters are performed regularly using specific information such as length of pipe, installation year, type of meter and historical unit cost. For specific plant such as transmission mains, information about the length and size of pipe retired and the year of installation is provided by the project manager responsible. Structures and measurement and regulator equipment are retired based on specific information such as year of installation provided by the project manager responsible. For assets subject to amortization accounting treatment such as computer hardware and software and tools and equipment, as approved by the Commission, assets are retired at the end of their estimated useful life, with no gains/losses recorded.

In response to this Directive, FEI has reviewed its asset records for evidence of assets that are not in use. At any given time, FEI does have some service lines and mains that are not in use either due to customers not yet connecting, or customers that are not currently taking service but are expected to in the future. These assets do not go through the retirement process discussed above because FEI has an expectation that the assets will be placed into service again in the future. If there is an expectation that the asset will be used in the future, the most cost-effective option is to keep the assets available for future service even though they are not currently in use. In addition, as reiterated below, retiring the asset would have the result of removing the net book value from plant in service and transferring it to the Gain/Loss Deferral account with the same effective recovery from customers through rates. As a result, the only reasonable alternative is to continue to keep these assets available for future service until such time as there is no expectation that they will be used in the future. FEI therefore does not believe any action should be taken regarding the assets that are not in use.

3.5.2 Directive re Asset Losses

The Commission made the following directive on page 88 of the 2012-2013 RRA Decision (Directive No. 36, Appendix A, page 7):

> *"While losses of this nature may be a part of group asset depreciation, the Commission Panel directs the Utility to disclose specific information in future filings with the Commission. The disclosures should include the following:*
>
> 1) *Future revenue requirements applications shall include details of actual asset losses, by asset class, for the past 10 years. They shall also include a forecast of losses, by asset class, for the remaining asset class, unadjusted for capital additions expected to occur outside the test period. As asset losses are expected under group depreciation, the Commission Panel believes that a projection of these losses should be readily determinable and should directly tie into depreciation forecasting methodology. When the Utilities obtain future depreciation studies, the study expert should incorporate this loss-forecast schedule into the study and should explain how the amounts have been taken into account in the asset class depreciation rates.*
> 2) *Future revenue requirements applications shall detail efforts made to minimize early asset retirements and to demonstrate how the utility intends to maximize the value of assets in use. As group depreciation methodology determines assets' useful lives on an average basis, the Commission Panel expects that at least some of the assets should be expected to last longer than their estimated useful lives. The Utilities shall describe the steps taken to determine which assets these might be and how the Utilities intend to identify, maintain and repair such assets. Furthermore, this process should incorporate capital asset maintenance plans to demonstrate how the value of assets in use is to be maximized such that assets are not just replaced, on a blanket basis, at the end of the assets' average service life."*

Item (1) Asset Losses/(Gains) by Asset Class

The asset losses/(gains) by asset class for the past 10 years are provided in Table D3-2 below. Those asset classes that show a positive amount represent net losses and those that show a negative balance represent net gains. A net loss for an asset class should not be interpreted to mean that all assets that were retired in that asset class incurred losses; instead it indicates that the asset class as a whole incurred a loss, but that individual assets within the class may have realized gains or losses.

Table D3-2: Historical Net Asset Losses / (Gains) by Asset Class ($ thousands)

Particulars (1)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
INTANGIBLE PLANT										
461-00 Transmission Land Rights	-	-	-	-	-	-	(17)	(35)	-	-
402-01 Application Software - 12.5%	-	-	-	-	-	-	(3,160)	-	-	-
402-02 Application Software - 20%	-	-	-	-	-	-	101	-	-	-
	-	-	-	-	-	-	(3,076)	(35)	-	-
MANUFACTURED GAS / LOCAL STORAGE										
432 Manufact'd Gas - Struct. & Improvements	4	13	(0)	1	-	-	-	-	-	-
433 Manufact'd Gas - Equipment	0	-	-	-	-	-	-	-	-	-
437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-
442 Structures & Improvements (Tilbury)	-	-	2	(6)	12	2	2	-	-	-
443 Gas Holders - Storage (Tilbury)	153	10	-	20	19	2	-	-	-	-
449 Local Storage Equipment (Tilbury)	46	-	76	54	56	684	231	-	-	-
	203	23	78	69	87	688	233	-	-	-
TRANSMISSION PLANT										
460-00 Land in Fee Simple	121	(172)	-	-	-	-	-	(39)	-	-
461-00 Transmission Land Rights	(1)	(1)	-	-	-	-	1	-	-	-
462-00 Compressor Structures	-	-	-	-	(3)	10	(1)	-	-	206
463-00 Measuring Structures	51	91	-	-	16	-	3	-	4	-
464-00 Other Structures & Improvements	-	-	-	-	2	-	7	-	-	-
465-00 Mains	1,605	721	560	59	188	66	578	38	291	1,537
465-10 Mains - Byron Creek	-	-	-	-	-	-	-	-	-	-
466-00 Compressor Equipment	41	2	19	-	-	49	3	296	366	(4)
467-00 Measuring & Regulating Equipment	235	1,464	110	44	173	8	120	43	5	53
467-10 Telemetering	12	(88)	41	102	(493)	-	(1)	-	8	1
468-00 Communication Structures & Equipment	(9)	-	-	(1)	-	-	-	-	-	-
	2,055	2,017	729	204	(118)	133	710	338	673	1,793
DISTRIBUTION PLANT										
470-00 Land in Fee Simple	11	(59)	-	-	-	5	(0)	(63)	-	-
472-00 Structures & Improvements	36	1	(1)	8	57	55	36	(5)	3	-
473-00 Services	1,554	7,096	2,174	5,249	6,698	7,059	8,232	1,983	2,470	5,834
473-00 Services - LILO	9	12	52	42	35	37	26	40	37	110
474-00 House Regulators & Meter Installations	3,562	3,572	4,553	4,593	3,487	4,767	4,624	8,383	27	296
475-00 Mains	164	900	586	1,412	1,581	2,509	2,171	634	580	1,587
475-00 Mains - LILO	4	13	4	24	21	21	1	0	17	2
476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-	-
477-00 Measuring & Regulating Equipment	(639)	442	324	295	194	764	381	79	160	724
477-00 Telemetering	30	7	-	0	2	(2)	(58)	1	(40)	33
477-10 Measuring & Regulating Equipment - Byron Creek	78	-	-	-	-	-	-	-	-	-
478-10 Meters	1,001	1,184	3,351	1,416	622	2,430	1,772	3,475	2,227	2,919
478-20 Instruments	(2)	-	-	-	-	-	-	-	-	-
	5,808	13,168	11,043	13,038	12,698	17,643	17,185	14,528	5,481	11,506
GENERAL PLANT & EQUIPMENT										
480-00 Land in Fee Simple	-	-	59	(55)	-	-	-	-	-	-
482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-	-
482-10 Frame Buildings	82	(14)	1	14	(3)	161	11	-	72	-
482-20 Masonry Buildings	50	-	-	84	10	403	166	-	-	-
482-30 Leasehold Improvement	(70)	575	(459)	(10)	17	-	12	-	-	-
483-30 GP Office Equipment	6	4	(0)	-	(0)	0	0	-	25	82
483-40 GP Furniture	30	359	(596)	-	(0)	0	0	-	-	-
483-10 GP Computer Hardware	(47)	59	(139)	-	(1,145)	0	0	-	-	(2)
483-20 GP Computer Software	(138)	(340)	(1,018)	-	(1,389)	0	4,273	-	8	-
484-00 Vehicles	(33)	(17)	31	(84)	(61)	0	(25)	(15)	(3)	(3)
484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	(122)	(100)
485-10 Heavy Work Equipment	-	-	-	58	(37)	(9)	-	-	-	25
485-20 Heavy Mobile Equipment	-	-	(0)	26	0	-	-	-	3	13
486-00 Small Tools & Equipment	(291)	(33)	72	(53)	(1)	(1)	0	-	1	(1)
487-30 VRA Compressor Installation Costs	-	-	-	-	288	-	-	-	-	-
488-10 Telephone	1	23	(15)	(34)	9	-	-	-	66	-
488-20 Radio	0	(20)	0	-	(17)	0	0	-	0	-
489-00 Other General Equipment	-	-	-	-	263	-	-	-	-	-
	(409)	595	(2,063)	(53)	(2,067)	555	4,438	(15)	50	14
TOTAL NET LOSS	7,658	15,803	9,787	13,258	10,600	19,018	19,490	14,817	6,205	13,314

In addition, a forecast of net asset losses by asset class is provided in Table D3-3 below, representing FEI's estimates of the original cost of assets forecast to be retired including the forecast gains / losses (i.e. difference between the net remaining book value of assets and any salvage proceeds with losses representing inadequate recovery of depreciation) associated with the retirement of the assets. Consistent with the Commission's direction on the appropriate accounting treatment, the forecast gains and losses are being transferred from the respective plant-in-service accounts to the Gain/Loss Deferral account and amortized over a 20 year period. Since the forecast gain/loss is simply reclassified from the net plant in service section of the rate base to the deferrals section of the rate base, and the amortization period for the deferral account is aligned with the average service life of the impacted asset classes, the forecasting of the gain/loss, although helpful to provide an indication of future asset retirements, does not affect the forecast rates. As a result, the importance of the forecast gains / losses is lessened with no expected material difference on the cost of service.

The following table shows the forecasted net losses by asset classes for 2013 and 2014 with 2014 considered a representative year of the expected gains and losses during the PBR Period. The forecasted losses are determined based on the forecast level of abandonment activity for each asset class and where appropriate, recent historical average losses for the type of abandonment. The losses for 2015 through 2018 will be re-forecast as part of the annual rate setting process, with detail provided by asset class at that time in a similar fashion to the 2014 information below.

Table D3-3: Forecast Net Asset Losses for 2013 and 2014 ($ thousands)

Particulars	2013 Cost	2013 Net Loss	2014 Cost	2014 Net Loss
(1)	(2)	(3)	(4)	(5)
INTANGIBLE PLANT				
402-01 Application Software - 12.5%	6,015	-	3,738	-
402-02 Application Software - 20%	2,997	-	2,317	-
	9,012	-	6,055	-
TRANSMISSION PLANT				
463-00 Measuring Structures	21	5	21	5
465-00 Mains	374	2	374	2
465-00 Mains - INSPECTION	1,268	-	368	-
466-00 Compressor Equipment	340	-	288	-
467-00 Measuring & Regulating Equipment	131	23	131	23
467-10 Telemetering	22	-	31	-
	2,157	30	1,213	30
DISTRIBUTION PLANT				
472-00 Structures & Improvements	21	7	21	7
473-00 Services	3,185	2,053	3,185	2,053
474-00 House Regulators & Meter Installations	284	57	6	2
475-00 Mains	1,049	549	1,049	549
477-00 Measuring & Regulating Equipment	598	162	598	162
477-00 Telemetering	6	4	6	4
478-10 Meters	6,353	2,862	6,672	3,005
	11,496	5,693	11,538	5,782
GENERAL PLANT & EQUIPMENT				
482-00 Structures & Improvements	151	-	40	-
483-30 GP Office Equipment	303	58	92	24
483-40 GP Furniture	1,954	-	3,123	-
483-10 GP Computer Hardware	6,489	-	3,708	-
483-20 GP Computer Software	192	-	44	-
484-00 Vehicles - Leased	1,440	-	1,536	-
486-00 Small Tools & Equipment	963	-	2,003	-
488-10 Telephone and Radio Equipment	940	109	1,674	146
	12,432	167	12,221	169
TOTAL COST	$ 35,098		$ 31,027	
TOTAL NET LOSS		$ 5,890		$ 5,981

As can be seen in Table D3-3 above, the asset classes with the largest forecast losses are Distribution services, mains and meters, accounting for more than 90 percent of the $6 million loss forecast for 2014. These are the same asset classes that have historically been subject to significant retirements before the assets were fully depreciated, and which were discussed in detail in the 2012-2013 RRA. Overall, the trends that were identified at that time are expected to continue, and are described further below. However, as previously indicated in the 2012-

2013 RRA, the losses should be considered normal given the asset life profiles, with retirement losses and gains expected to net out to zero over the life of the assets.

Account 473 Services

For Services, the drivers of early retirements are twofold – customers and safety.

Retirements related to customers result from requests to retire services as a result of land development activities and specific requirements of customers. As the demand for housing in the more densely populated regions (i.e. Lower Mainland) increases, existing housing and land are being redeveloped with larger plots of land being subdivided and existing housing demolished to make way for multifamily housing (i.e. townhouses, condos). This is contributing to a shorter useful life observed than originally anticipated. Other customer driven requests include those resulting from homeowners performing building modifications and landscaping activities that often require the retirement of service line assets.

The other contributor to early service retirements is safety. FEI has a service retirement program to remove inactive services. An inactive service to a premise is a live gas service or meter with no existing customer. These assets continue to attract regular maintenance but are not presently being used for gas delivery. Inactive services are often forgotten by the property owner and represent a significant risk of third party damage. Removal of inactive services initiated by FEI improves the safety of the public, the natural gas delivery system and its employees.

Forecast services retirements are prepared using the forecast level of service abandonment activity. Based on the forecast activity level, service abandonments are determined using an average historical unit cost calculated for services retired over the last three years. Using the same forecast level of service abandonment activity, the projected gains / losses for services are calculated using an average unit “loss” for services retired over the last three years. Consistent with activities in prior years and the same explanatory contributors, retirements of services are expected to result in losses.

Account 475 Mains

For Distribution Mains, the reasons that mains may be retired earlier than their expected lives can be classified into two categories, customer and safety/reliability.

Where required to maintain the safety and reliability of the distribution system, the Company replaces the distribution mains earlier than expected in order to maintain the integrity of the pipe. Where the opportunity permits, FEI schedules mains pipe replacement to coincide with municipal or road construction activities in order to minimize the costs. Customer requests to relocate distribution mains may also lead to earlier retirement than expected. Highway construction, municipality activities and private industry development may result in FEI having to retire and relocate an existing main.

Forecast mains retirements are prepared using the forecast level of mains abandonment activity. Based on the forecast activity level, mains abandonments are determined using an average historical unit cost calculated for mains retired over the last three years. Using the same forecast level of mains abandonment activity, the projected gains / losses for mains are calculated using an average unit "loss" for mains retired over the last three years. Consistent with activities in prior years and the same explanatory contributors, retirements of mains are expected to result in losses.

Account 478 Meters

For meters, early retirements of meters are being driven by the introduction of the Measurement Canada mandated sampling plan SS-06. Refer to Section C4.4 Sustainment Capital expenditures for further discussion.

Forecast meter retirements are prepared using the forecast level of meter exchange activity. Based on the forecast activity level, meter retirements are determined using an average historical unit cost calculated for meters retired over the last three years. Using the same forecast level of meter exchange activity, the projected gains / losses for meters are calculated using an average unit "loss" for meters retired over the last three years. Consistent with activities in prior years and the same explanatory contributors, retirements of meters are expected to result in losses.

Regarding the final part of the Commission's direction in item #1, regarding future depreciation studies, Gannett Fleming which prepared the most recent depreciation study included as part of the 2012-2013 RRA confirms that the forecast asset losses will be incorporated into the next study in determining future depreciation rates. The forecast retirements and associated loss amounts along with the actual retirements and associated losses by asset class reported to date will be used in conjunction with other input (i.e. discussion with operating and management personnel, experience from other gas distribution companies, etc.) to determine the selection of the IOWA curves that best represents the estimated useful life of the different asset classes. Adjustments to asset depreciation rates are required on a regular basis to reflect changes in the expected lives of assets. The use of IOWA curves (or called survivor curves) provides a consistent method of estimating depreciation rates for the different asset classes.

Item (2) Efforts to Minimize Early Retirements and Maximize Value

FEI regularly retires and removes assets from service in the normal course of operating the gas utility business. In its asset replacement decisions, FEI focuses on ensuring the ongoing safety and reliability of the natural gas delivery system and maximizing the value of existing assets by ensuring replacements are made only where and when they are needed. Please refer to Section C4.4 Sustainment Capital Expenditures for further discussion of asset replacement considerations.

In Section C4.4, it is highlighted that the installation date of an asset is a consideration in asset replacement decisions, not as an indicator of age of the asset but rather as a means of determining characteristics that impact the probability of failure and the need to retire the asset. These characteristics or causal factors influence the actual age of retirement for the asset and may result in a different service life than originally anticipated. FEI makes asset replacement decisions with the view to mitigate asset risks and to ensure that the Company can continue to deliver gas safely and reliably while minimizing the impact on customers.

3.6 *SHARED AND CORPORATE SERVICES*

The Commission included the following directive on page 71 of the 2012-2013 RRA Decision (Directive No. 25, Appendix A, page 4):

> *"The Commission Panel directs the FEU to update both the Corporate and Shared Service Agreements for inclusion in their next revenue requirements application. Further, the Commission Panel directs the FEU to break activities of the FEU entities into two, distinct parts:*
>
> - *Those of traditional gas operations, and*
> - *Those of TES offerings*
>
> *so that costs attributable to each entity of the FEU can be clearly broken down by their TES component."*

The Commission included the following directive on page 140 of the 2012-2013 RRA Decision (Directive No. 62, Appendix A, page 11):

> *"For future revenue requirements applications, the FEU are directed to propose criteria which can be used to provide a better assessment of an appropriate overhead and sales and marketing cost allocation."*

This section discusses the Shared and Corporate Services studies undertaken for the traditional gas offerings. Regarding TES offerings, as a result of the AES Inquiry Report, FEI has engaged in discussions with Commission staff that were outlined in the FEU's letter of February 20, 2013 regarding "FortisBC Energy Utilities Clarification Request Related to Upcoming Revenue Requirements". In that letter, the FEU stated the following:

> *"The RRA will not address any of the directives in the AES Inquiry Report that relate to Thermal Energy Service ("TES") because all of the TES projects are undertaken by an affiliated regulated business, FortisBC Alternative Energy Services Inc. ("FAES"). Further, the FEU plan to file the RRA in the second quarter of 2013, and there is not sufficient time between now and then to comply with the directives in the AES Inquiry Report related to the scaled regulatory framework for TES utilities, which is pending the Commission staff conducted consultation process, and the allocation and recovery of the Thermal Energy Services Deferral Account ("TESDA"), or the recommendation regarding the Code of Conduct and Transfer Pricing Policy (""COC/TPP").*

Commission directives related to the treatment of the TESDA and recommendations with respect to the COC/TPP, which may impact the FEU's organizational structure and cost recovery, will be dealt with in future proceedings. As a result, the FEU will include an amount as a placeholder for the allocation of support costs to the TESDA in its RRA along with a request for a deferral account to capture the difference between the placeholder amount and the actual amount determined under the Code of Conduct and Transfer Pricing Policy review process. This approach ensures an efficient regulatory process as such issues related to TES are addressed once the regulatory framework for TES is established by the Commission.

The FEU and the Commission staff have tentatively agreed to start the COC/TPP review process in the Fall of 2013. This proposed timeframe considers the active participation of both the FEU and the Commission staff in numerous other regulatory proceedings in 2013.

Subsequent to updating the COC/TPP, the FEU will file an application regarding allocation and recovery of TESDA. Without clarity on the COC/TPP and the resulting costs that will be allocated to the TESDA, an analysis of the forecasted recovery from the TESDA is not possible."

FEU received a response to the letter on May 3, 2013 from the Commission staff, stating the following:

"FEU states that the Upcoming RRA will not address any of the directives in the AES Inquiry Report that relate to Thermal Energy Service (TES) because all of the TES projects are to be undertaken by FortisBC Alternative Energy Services Inc. (FAES).

FEU also observes that there is insufficient time prior to filing the Upcoming RRA to address the directives in the AES Inquiry Report related to the scaled regulatory review of TES activities, the allocation and recovery of the Thermal Energy Services Deferral Account (TESDA) or the recommendation regarding the Code of Conduct and Transfer Pricing Policy (COC/TPP). In FEU's view the directives related to the treatment of the TESDA and the recommendations with respect to the COC/TPP may impact FEU's organizational structure and cost recovery. FEU proposes to include a placeholder amount for the allocation of the support costs to the TESDA in its RRA along with a request for a deferral account to capture the difference between the placeholder amount and the actual amount determined under the COC/TPP review.

Commission Staff intend to explore the issue of separation/integration of FAES and FEI in the Upcoming RRA, including what functions and services are separated and which are integrated and the dollar amounts associated with each. Commission Staff expect that the planned proceeding on the COC/TPP would then set out the separation/integration issues that are decided in the RRA into policies."

As a result of these other ongoing processes, FEI has not addressed the allocation of corporate and shared services to the TES offerings in this Application, but has requested a deferral account to ensure that natural gas ratepayers are held whole. However, FEI has confirmed through its work on the shared and corporate service models that using the Massachusetts Formula for allocating corporate services costs to the TES offerings results in a much lower cost allocation (i.e. less than $100 thousand per year) than the placeholder that has been included. The Massachusetts Formula has been employed for the traditional natural gas business to allocate corporate services costs (i.e. it is approved currently for use in allocating FHI corporate services costs to the FEU). The Massachusetts Formula is extensively used in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned.

3.6.1 Shared Services

Sharing of resources amongst the FEU under Shared Services arrangements enables the Companies to maintain the benefits of economies of scale by having a single management and support structure while avoiding duplication of work and allowing customers to benefit from the efficiencies realized. This beneficial relationship is forecast to continue into the future.

Since FEI completed a review of the Shared Services agreement and cost allocation approach as part of the 2010-2011 RRA with validation by KPMG, no changes in methodology have occurred since the time of the 2009 review that would warrant making any change to the Shared Service Agreement currently in place. For this filing, FEI updated the approved model for changes in the department's forecast O&M numbers along with changes in the organization structure, and has provided updated agreements in Appendix F1 in accordance with the Commission's direction. The cost allocation methodology and drivers used remain the same as that previously approved.

Common services delivered on a Shared Services basis include:

- Corporate;
- Finance and Regulatory Affairs;
- Customer Service;
- Human Resources;
- Environment, Health & Safety
- Energy Supply and Resource Development;
- Information Technology;
- Facilities;

- Operations Support;
- Engineering Services and Project Management;
- Operations; and
- Energy Solutions & External Relations.

3.6.2 Summary of Shared Services Results

The following table provides the comparative amounts of total Shared Services costs for the FEU. The reference to 2013 Base is to the 2013 Base O&M that is used for setting rates under the PBR proposal. Please refer to Table C3-2 for a reconciliation of 2013 Base O&M.

Table D3-4: Total Shared Services Costs

($000s)	2013 Projection	2013 Approved	2013 Base	Base vs Approved	% Allocation
Total Costs Included in Shared Services Pool	93,358	87,109	96,432	9,323	100.00%
Allocated to FEVI	9,399	8,996	9,630	634	6.80%
Allocated to FEW	246	250	255	5	0.05%
Allocated to FEI	83,713	77,863	86,547	8,684	93.15%

3.6.3 FEI and FEVI Shared Services

The Shared Services agreement between FEVI and FEI, including the method of allocation, is unchanged from that approved for the 2012-2013 RRA. A recent review of the Shared Services indicated that the amount of annual Shared Services to be allocated from FEI to FEVI is estimated to be $9.6 million for the 2013 Base Year as illustrated in Table D3-4.

The FEVI 2013 Base Year allocation in comparison to the 2013 Approved is higher by approximately $600 thousand. Increased resources totalling to about $200 thousand per year are required in the dispatch centre to plan and coordinate field resource requirements. Another $200 thousand per year is related to the true-up of FEVI's share of FEU's directed $4 million O&M productivity factor from the 2012-2013 RRA Decision. In determining FEVI's share of this reduction for 2013, estimates of the impact on the shared departments were originally used. With updated information available regarding the allocation by department, FEI is in a position to true-up the calculation. Lastly, the remaining $200 thousand is to account for FEI's pension/OPEB and accounting related changes impact on shared services.

The cost allocation drivers used include the number of employees and customers. For shared services costs allocated by employees, using 2012 numbers, FEI is allocated 92.2 percent, FEVI 7.7 percent and FEW 0.1 percent. For those shared services costs allocated by customers, following the cost allocation approach previously approved by the Commission, FEI is allocated 90 percent and FEVI 10 percent.[65]

FEI and FEVI believe that by providing common services through a Shared Services approach, the costs are being optimized between the two organizations for the benefit of all customers. To properly reflect the value of activities provided by FEI to FEVI, the Company requests that the Commission approve the allocation of costs for Shared Services between FEI and FEVI following the methodology as outlined in the discussion above for the 2013 base year, subject to FEVI receiving regulatory approval for the allocation in its next RRA filing.

3.6.4 FEI and FEW Shared Services

The Shared Services agreement between FEW and FEI, including the method of allocation, is unchanged from that approved for the 2012-2013 RRA. The amount of annual Shared Services to be allocated from FEI to FEW is estimated to be approximately $255 thousand for the 2013 base year, consistent with that approved for 2013. To properly reflect the value of activities provided by FEI to FEW, the Company requests that the Commission approve the allocation of costs for Shared Services between FEI and FEW for the 2013 base year subject to FEWI receiving regulatory approval for the allocation in its next RRA filing.

3.6.5 Sharing of Services with FortisBC Inc.

Since 2010, the FEU and FortisBC Inc. (FBC) have been sharing common resources starting with the sharing of the Executive Management team. More recently, the sharing of resources between FEI and FBC has continued as the organizations streamline operations and processes.

In this Application, sharing of resources between FEI and FBC, except for the Executive Management team, have continued with the approved cross charge process such that the cross charge includes a fully loaded wage including benefits and time away, with no overhead or facilities fees assigned. Executive Management time is being allocated on the basis of the Massachusetts Formula. As mentioned earlier in Section A3, given the evolving nature of integration efforts between the gas and electric businesses, the traditional timesheet allocation approach continues to be the appropriate approach to allocate the majority of shared costs between the two organizations.

3.6.6 Corporate Services

The corporate services function consists of certain specialized functions that reside in FHI and Fortis Inc. and that provide expertise to the FEU. These services are shared, providing economies of scale to the FEU. The costs are allocated to each of FEI, FEVI and FEW.

While there has been a limited amount of change since 2009 in the Corporate Services costs, FEI has engaged KPMG to review the corporate costs. The report of KPMG is included in

[65] If the allocation is based on actual customer count for 2012, the charges allocated to FEVI would increase by approximately by $400 thousand per year.

Appendix F2. While the costs of many of the various cost centres have changed in relative proportion, the total 2013 projected fee to FEU is unchanged from what was approved.

The services to be performed by Fortis Inc. are consistent with the services provided by Fortis Inc. to FHI since 2009, which were approved by the Commission for recovery in respect to both the 2010-2011 RRA and 2012-2013 RRA. At the Fortis Inc. level, these services are strategic in nature and consist of the following functions:

- Executive - provide strategic direction, leadership and management for Fortis Inc., manage the organizational structure, financial planning, maintaining controls and internal systems, employee relations, external communication, board relations, regulatory compliance, provision of legal services, maintain internal and external audit activities, and corporate financing and budgeting.
- Treasury and Taxation - performs Fortis Inc. treasury services and provides oversight to subsidiary companies for debt and equity financings, maintaining the capital structure, corporate cash management and forecasting, management of hedging activities, preparation of corporate tax returns, tax planning, coordinating corporate tax audits, rating agency process, and corporate credit facilities.
- Investor Relations - manage analyst, investor and shareholder communications, coordinate Fortis Inc. annual general meeting, preparation of quarterly investor relations reports, manage public and media relations, maintain Fortis Inc. website, manage dividend reinvestment and share purchase plans, and oversight over the Annual Report preparation process.
- Financial Reporting - preparation of monthly, quarterly and annual consolidated and non-consolidated Fortis Inc. financial statements, coordination with external auditors, analysis of financial information, preparation of the Annual Information Form for Fortis Inc., Annual Report for Fortis Inc., quarterly and annual Management Discussion and Analysis for Fortis Inc. and other continuous disclosure documents for Fortis Inc., coordinate consistent accounting policy treatment across the Fortis group, oversight and review of compliance with US GAAP, preparation of the company-wide quarterly forecast consolidated earnings for Fortis Inc. and earnings per share and maintaining internal controls over financial reporting for Fortis Inc.
- Internal Audit - performs Fortis Inc. internal audit activities, provides oversight over the internal audit function at the Fortis subsidiary companies, administers and monitors reports of allegations of suspected improper conduct or wrong doing, development of a company-wide Enterprise Risk Management program approach.
- Board of Directors - annual strategic planning and risk management activities, selecting and evaluating the CEO, appoint officers, review and approve all material transactions, evaluate Fortis Inc.'s internal controls relating to financial and management information systems, establish and maintain policies regarding communication and disclosure with stakeholders, develop and maintain governance procedures.

The eligible 2013 projected costs for allocation to FHI and other Fortis Inc. owned entities are summarized in Table D3-5 below.

Table D3-5: Eligible Projected Costs for Allocation to FHI and other Fortis Inc. Owned Entities

2013 Estimated Costs		FHI	Other	Total
Services ($000s)		41.94%	58.06%	100%
Executive		1,161	1,607	2,768
Treasury and Taxation		191	265	456
Investor Relations		700	968	1,668
Financial Reporting		721	998	1,719
Internal Audit		315	436	751
Board of Directors		868	1,201	2,069
Other		1,082	1,498	2,580
Subtotal		5,037	6,974	12,011
Less: Fortis Properties Management Fee Revenue		(629)	(871)	(1,500)
Total		4,408	6,103	10,511

The forecast costs for 2014 include a three percent increase in overall costs as compared to 2013 Projected, multiplied by the same FHI allocation percentage of 41.94 percent. The allocation percentage represents the total assets of FHI as a percentage of the total assets of Fortis Inc. Fortis Inc. has consistently allocated costs across its regulated holdings by using the percentage of assets as its allocation factor.

FHI is responsible for providing key corporate functions directly to each of the FEU. As a result of the integration efforts between the FEU and FBC, a number of the functions below provide support to FBC, as well as providing support to non-regulated affiliates which are not directly owned by FHI. The expected time spent on those activities, primarily based on time estimates, has been removed from the cost pools eligible to be allocated to FEI, FEVI and FEW.

The corporate services functions costs consist of the following:

- Board of Directors - ensure all continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, manage the relationship and corporate activities of the FHI Board of Directors, and develop and maintain governance procedures and policies. The Board of Directors is a joint Board that is shared with FortisBC Inc. All costs incurred for compensation and other Board expenses have been shared between FHI and FBC based on an expanded Massachusetts method which incorporates operating revenue, payroll, and average net book value of capital assets plus inventories. The costs reflected in this Application are the costs less any amounts recoverable from FortisBC Inc.

- Treasury and Cash Management – execute short and long term financings, cash management and forecasting, arrange operating credit facilities, and negotiate bank-service fees for all FEU entities; responsible for treasury related controls and compliance, compliance reporting, hedging of interest rate and foreign exchange risks, managing the rating agencies, maintaining bank and debt investor relationships, investor and shareholder communication, preparing regulatory submissions in support of ROE, capital structure and financing related matters, providing credit and counter-party credit risk management and assistance in negotiating physical and derivative commodity contracts to the Energy Supply and Resource Development department, assessment and monitoring of physical and financial counterparties, developing appropriate derivative and counterparty policies.
- External Financial Reporting – preparation of monthly, quarterly and annual consolidated and non-consolidated financial statements (for FHI, FEI, FEVI and FEW), coordination with external auditors, analysis of financial information, assisting in the preparation of the Annual Information Form, quarterly and annual Management Discussion and Analysis and other continuous disclosure documents, coordinating consistent accounting policy treatment across the FEU, preparing for and implementing US GAAP changes, preparing quarterly forecasts of consolidated earnings and maintaining internal controls over financial reporting.
- Taxation – provides a full range of services in income and commodity taxes including financial reporting for taxes (year-end and quarterly tax provisions for current and future income taxes), tax compliance (filing of tax returns, coordination of tax audits), regulatory tax accounting (tax calculations for rate cases and annual reports), tax planning including guidance and support for significant transactions, and tax dispute management and resolution.
- Internal Audit – developing, planning and conducting audits/reviews, conducting annual risk assessment processes, monitoring and evaluating the effectiveness and efficiency of internal controls.
- Risk Management and Insurance – ensuring compliance with the TSX requirements on risk management, arranging for coverage based on assessed potential risk, and ensuring an appropriate and prudent insurance program.
- Legal – provides all legal services and counsel to various departments on issues including regulatory, environmental, business development, employment, securities, financing and intellectual property, and manages legal matters that have been outsourced to outside legal counsel.
- Human Resources Compensation and Planning – consults with management on the maintenance, development and governance of employees and retirees, provides

assistance on annual wage and salary increases, ensure that employment practices are in compliance with applicable regulations and legislation.

- Facilities and Support – provides building space, shared services, computer software, office supplies and stationery, admin and computer outsources.

Total Pool of Costs for Allocation to FEU

The costs discussed above that are incurred by Fortis Inc. on behalf of the FEU are allocated to FHI. These costs and other corporate costs incurred by FHI on behalf of the FEU form the pool of costs that are eligible to be allocated to each of FEI, FEVI and FEW.

Of the pool of costs, certain costs incurred in support of the utilities are eligible for inclusion in customer rates and are passed on to the utilities in the form of a corporate services fee. Other costs are specific to the holding company and have been excluded from the calculation of the FHI corporate services fee. These excluded costs are:

- All identifiable corporate development and capital management (shareholder related) costs;
- Legal fees incurred for non-regulated entities;
- Pension costs related to executive bonuses;
- Any fees associated with FHI's International operations; and
- Ineligible components of the Fortis Inc. management fee including Defined Benefit Pension, Defined Contribution Supplemental Employee Retirement Plan on executive bonuses and stock compensation costs which were not already excluded by Fortis Inc.

The following table is a summary of the total corporate services costs (net of the exclusions noted above) that form the total pool of costs that is allocated to the FEU and shows the actual costs incurred in 2010 through 2012 with the projected and approved costs for 2013.

Table D3-6: Corporate Services Costs 2010 through 2013

($000s)	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2013 Approved
Board of Directors	772	498	486	711	686
External Financial Reporting	1,296	993	1,226	1,167	1,278
Human Resources Compensation & Plan	370	243	486	294	294
Internal Audit	706	911	734	774	773
Legal	1,804	2,317	1,856	1,940	1,702
Risk Management and Insurance	314	306	372	289	397
Taxation	795	876	919	1,019	987
Treasury and Cash Management	795	951	923	900	1,087
Facilities and Support	942	887	937	920	977
Fortis Inc Management Fee	3,801	5,028	5,018	4,408	5,057
	11,597	13,009	12,958	12,423	13,238

Allocation of Corporate Services costs

The costs from Fortis Inc. are allocated to FHI using the assets by subsidiary driver which is a valid cost driver given the organizational structure of Fortis Inc.

The methodology selected by FHI to allocate the corporate services costs charged to FEI, FEVI and FEW incorporates the Massachusetts formula, which is the same allocation methodology previously approved by the Commission. The results of the Massachusetts formula at December 31, 2012 would have allocated 82.7 percent to FEI, 16.1 per cent to FEVI and 0.4 percent to FEW with the remainder of the costs, being 0.8 percent, allocated to the other subsidiaries of FHI. As part of the Negotiated Settlement Agreement in 2009 for the 2010/2011 RRA, the parties to the agreement agreed on a set dollar amount for FEVI with the remaining difference between the agreed amount and the Massachusetts formula driven amount being allocated to FEI. A similar methodology was applied in 2012/2013.

As shown in Table D3-7 below, the 2013 Projected fee for FEI, FEVI and FEW is unchanged compared to the 2013 Approved fee.

The fees to all entities are expected to increase by inflation in 2014 and beyond.

The annual Corporate Service costs to be allocated from FHI to FEI, FEVI and FEW are as shown in D3-7 below.

Table D3-7: Annual Corporate Service Costs Allocated from FHI

Mgmt Fee Recovery	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2013 Approved
(000s)					
FEI	9,556	9,652	10,718	11,031	11,031
FEVI	1,087	1,097	1,140	1,196	1,196
FEW	49	49	49	50	50
Total - FEU	10,692	10,798	11,907	12,277	12,277
Other	905	2,211	1,052	146	961
	11,597	13,009	12,958	12,423	13,238

While the overall structure of FHI is similar throughout the comparative period 2010- 2013, the number of active other subsidiaries has decreased due to certain subsidiaries, like CustomerWorks LP, ceasing activities during this time frame. This has resulted in a decreasing amount of the costs being incurred by other subsidiaries.

FEI considers the above allocation to be reasonable and representative of the activities and their value provided by FHI to FEI, FEVI and FEW.

The FEU portion of the corporate service costs in Table D3-7 above have been allocated to the appropriate operating departments in FEI to align with the presentation of costs with the Activity View of the O&M under the Uniform System of Accounts. The appropriate allocations of these costs to FEVI and FEW are included in the Corporate department.

3.7 *CAPITALIZED OVERHEAD*

In general, utilities operate in a very capital intensive industry where an ongoing capital program is required to sustain the current system and to meet load growth. Therefore, the Capital Expenditure Plan and construction management is a significant activity of the Company. Construction not only involves actual physical construction, but also requires planning, regulatory approval, budgeting, project management and accounting as well as other activities. Many of these activities can be directly charged to specific projects; however some of these activities cannot be viewed as directly attributable to a specific project. The fact that the activity cannot be directly attributable to a specific project does not necessarily mean the activity was not performed in support of the capital program. Therefore, the Company, as per common industry practise and the Uniform System of Accounts, charges a certain portion of total operating and maintenance costs to capital.

Capitalized overhead is calculated by applying the overhead capitalization rate of 14 percent to Gross Operations & Maintenance (O&M net of direct charges to capital and other non-O&M accounts). Capitalized overhead is then charged on a pro rata basis (based on capital additions in the period) to the appropriate asset account. CPCN projects do not attract capitalized overhead as any overhead required for the CPCN is directly charged to the project. Similarly some other asset accounts such as land, land rights, general plant assets and meters do not attract capitalized overhead.

As an example and for illustrative purposes only, the calculation and allocation of capitalized overhead is determined as follows:

Table D3-8: Example of Calculation and Allocation of Capitalized Overheads

Capitalized Overhead Methodology		($ millions)
O&M Before Direct Charge-outs		272.3
Less: Direct Charge-Outs		(36.3)
O&M After Direct Charge-outs		236.0
Less: Capitalized Overhead @	14.0%	(33.0)
Net O&M		203.0
Allocation of Capitalized Overhead		
(Based on Capital Additions)		
Distribution	71%	23.6
Transmission	28%	9.2
All Others	1%	0.2
		33.0

As part of the 2010-2011 NSA for FEI, pursuant to BCUC Order G-141-09, Page 15 of Appendix A, the Parties agreed to a change in the overheads capitalized rate to 14 percent of O&M for 2010 and 2011 which reflected the approximate actual overheads capitalized rate for 2009.

In the 2012-2013 RRA the Company proposed that the overheads capitalization rate remain at 14 percent of O&M during the 2012 and 2013, which was accepted by the Commission, but with the following directive found at page 78 of the 2012-2013 RRA Decision (Appendix A, page 4, directive 29):

> *"The Commission Panel directs the FEU to update their capitalized overhead methodology using relevant accounting standards in the next test period. The Commission Panel further directs the FEU to obtain a report on this methodology from a qualified independent third party for inclusion in their next revenue requirements application."*

In November 2012, the Company sought clarification from the BCUC as to whether the capitalized overhead study should be undertaken under US GAAP with consideration of ASC 980, as well as whether it is necessary to have an additional study prepared under US GAAP without consideration of ASC 980. The Company noted that it had prepared a study in 2009 under IFRS guidance (IFRS study) that would be applicable under US GAAP without consideration of ASC 980.

The Commission responded that the Company would not be required to prepare another study under US GAAP without consideration of ASC 980 if:

- The Company files the IFRS study with its next Revenue Requirements Application (RRA) as a substitute for a study under US GAAP without consideration of ASC 980; and
- The Company has a 3rd party provide a summary of any differences between what would be included under IFRS and what might be included under US GAAP and their impact, if any, on the IFRS study with its next RRA.

The Company has included the IFRS study in Appendix F3 to this Application. The Company engaged KPMG to perform a review of the updated the capitalized overhead methodology under US GAAP with consideration of ASC 980 in Appendix F3 (2013 Study) to this Application. The 2013 Study also provides a summary of any differences between what would be included under IFRS and what might be included under US GAAP and their impact, if any, on the IFRS study.

The 2013 Study provides two estimates of a reasonable overheads capitalized rate based on 2013 approved O&M. The 2013 Study provides details of the two estimating methods - a Survey based methodology and a Mathematical based methodology. The Survey based approach suggests a 12 percent rate while the Mathematical based approach yielded an 11 percent rate.

The Company is of the opinion that there has been no material change in utility operations since the 2012-2013 RRA that would require a change to the overheads capitalized rate. Therefore, the Company is proposing that the overheads capitalization rate remain at 14 percent of O&M.

Also, as illustrated in Table D3-9 the Company is expecting forecast net capital expenditures for the period 2014 – 2018 to remain at levels that are higher than in the 2010 – 2013 period. Based on this summary, FEI also concludes that there is no basis to recommend a change in the overhead capitalization rate during the PBR Period, as the regular capital spending level is expected to remain relatively constant, and therefore the percentage of O&M that supports capital is expected to remain relatively constant. In addition the rate has been shown to be reasonable based on the two estimating methods employed.

Table D3-9: Actual and Forecast Net Capital Expenditures ($ millions)

	2010 Actual	2011 Actual	2012 Actual	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Capital Expenditures	82.4	95.7	102.6	126.2	132.8	132.6	132.2	136.2	137.8
Average 2010 – 2013	101.7								
Average 2014 – 2018					134.3				
Average 2010 – 2018	119.8								

In summary, the current overhead capitalization approach is consistent with other Canadian and U.S. utilities and FEI's capitalization rate of 14 percent of O&M is reasonable and within a range of other utilities surveyed by the Company. Finally, based on the forecast capital expenditures over the 2014 – 2018 period, the current rate should be held constant over the same period.

3.8 *SUMMARY OF ACCOUNTING POLICIES*

FEI has considered each of the areas of Generally Accepted Accounting Principles, two internal accounting policy changes, and a change to purchasing from leasing vehicles, and reviewed its treatment of cash working capital, depreciation, negative salvage, asset losses, shared and corporate services, and capitalized overheads, and has reflected these items as discussed above in the financial schedules attached in Section E of this Application, and in the calculation of rates for 2014.

4. DEFERRALS

FEI has considered the following factors with respect to continuing existing deferral accounts and seeking deferral account treatment in different matters:

- Maintain those previously approved accounts that continue to provide benefits as appropriate to customers and FEI from 2014 through 2018[66];
- Create new mechanisms to address uncontrollable or non-recurring matters appropriately; and
- Discontinue the use of certain deferral accounts that are no longer required.

Consistent with past practice, FEI has organized its deferral accounts into the six categories described in Table D4-1.

Table D4-1: Deferral Accounts Providing Benefits to Customers and the Utilities

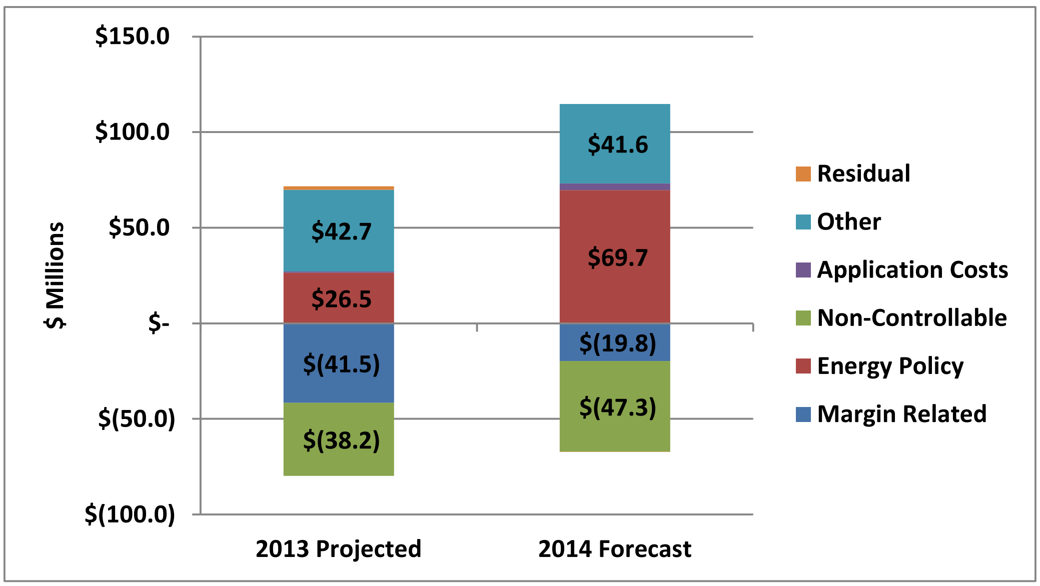
Deferral Account Category	General Purpose & Description
Margin Related	• Decrease the volatility in rates caused both by such factors as fluctuations in gas prices and the significant impacts of weather and other changes on use rates. • Deferring the cost and delivery margin impacts arising from un-forecast variations in these types of factors and recovering the impacts from, or refunding the impacts to customers over a longer period of time is an effective method of reducing rate volatility.
Energy Policy	• Capturing costs associated with changing energy policies that focus on energy efficiency, conservation and the environment. • Deferring and amortizing these costs matches the costs of the programs with the period of time that the benefits are expected to be realized by customers.
Non-Controllable Items	• Items which are either outside of the Company's control or where the Company has limited ability to influence the costs. • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers.
Deferred Costs of BCUC Applications	• Costs incurred consist of legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs.
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature.

[66] As per the Decision attached to Commission Order No. G-7-03 in referencing the approval of individual deferral accounts, the Commission wrote: "The Commission believes that its Orders supporting these requests continue in force until a change is approved by the Commission. For greater certainty, the Commission approves the continuation of amortization rates as previously ordered." Consistent with that Decision, FEI has continued to employ deferral accounts previously approved by the Commission.

Deferral Account Category	General Purpose & Description
Residual	• Deferral accounts which are no longer required and the Company is proposing to discontinue the use of the account. • Typically the proposal is to fully amortize any remaining balances.

The forecast mid-year balance of unamortized deferred charges in rate base for FEI is approximately $47.7 million in 2014 and is driven largely by the balances in several deferral accounts including the Energy Efficiency and Conservation, NGT Incentives, Pension and OPEB Variance, Gains and Losses on Asset Disposition and 2011 Customer Service O&M and COS deferral while partially offset by the net variance between the Pension and OPEB Funding accounts. The forecast mid-year balances range from $61.2 to $76.7 million in 2015 to 2018; however, the actual balances to be recovered in rates for these future years will be addressed in the annual rate setting process. Figure D4-1 provides the mid-year deferral account balances summarized by deferral account category.

Figure D4-1: FEI Forecast Mid-Year Balances of Deferral Accounts by Category



The section below includes a discussion on new rate base deferral accounts and changes to existing rate base deferral accounts, including discontinuing the use of many deferral accounts that are no longer required. With respect to FEI's other currently approved accounts, the original rationale that justified establishing the accounts and the associated financial treatment remains. They are expected to continue to accumulate new amounts during the PBR Period, and should remain in place. A summary of all existing approved rate base deferral accounts expected to continue accumulating new amounts through the PBR Period, and which FEI is therefore proposing to continue, can be found in Appendix F4. For a discussion on non-rate base deferral accounts, including the Thermal Energy Services Deferral Account, please refer to Appendix F5.

4.1 NEW ACCOUNTS

FEI is proposing to create two new deferral accounts to address the costs of the present application and the TESDA overhead allocation variance, as described below.

4.1.1 2014-2018 PBR Application

FEI will incur costs in 2013 and 2014 related to the current PBR Application. Costs incurred consist of legal fees, costs for expert witnesses and consultants, costs related to independent studies, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. Consistent with past practice, FEI requests approval to capture the full costs of this Application in this account and to amortize these costs over a five-year period, which represents the period covered by the PBR Application. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates beginning the following year.

The proposed deferral account and treatment is consistent with the Commission's acknowledgment of the merits of such accounts in 2012-2013 RRA Decision. It stated on p.118:

> *"The Commission Panel acknowledges that this Application, the FEU Inquiry and the upcoming Long Term Resource Plan application will have an impact on ratepayers beyond the current year and that deferral of these accounts (sic) is warranted. Further, the Commission Panel acknowledges that the numerous regulatory proceedings that the FEU are involved in create uncertainty with respect to the magnitude of the costs that will be incurred by the FEU, thus also warranting the use of deferral accounts."*

4.1.2 TESDA Overhead Allocation Variance

This account will capture the difference between the currently forecasted amount of overheads recovered by FEI from thermal energy customers and any changes to the allocation that may result from the TESDA Report and the Transfer Pricing Policy/Code of Conduct review requested in the AES Inquiry[67] to be undertaken with the Commission later in 2013. The amount of O&M currently forecasted to be recovered from thermal energy customers in the 2013 O&M Base is $854 thousand,[68] as approved by Commission Order G-44-12. This amount will be inflated by the O&M formula for the PBR Period.

[67] Order G-201-12, Pages 89 and 90

[68] Page 4 of G-44-12 included a $750 thousand recovery for overhead and sales and marketing costs. Page 65 of G-44-12 included an additional $104 thousand recovery of IT O&M costs from the TESDA.

FEI will address the disposition of any amounts recorded in this deferral account in its first Annual Review to be held in 2014.

4.2 CHANGE IN AMORTIZATION PERIOD OR CONTENT OF ACCOUNTS

FEI is proposing alterations to a number of accounts as discussed below.

4.2.1 Midstream Cost Reconciliation Account (MCRA)

FEI is requesting to modify the amortization period for the MCRA to amortize one-half of the cumulative MCRA deferral balance at the end of the year into the next year's midstream rates. This change is the result of US GAAP requirements relating to revenue recognition for rate-regulated entities with alternative revenue programs. US GAAP defines an alternative revenue program as a program that adjusts "billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts)". The MCRA captures weather variations in commodity rates, and thus falls within the US GAAP definition of an alternative revenue program. In order for FEI to be able to recognize the additional revenue from the future recovery of the MCRA in customer rates, US GAAP requires that the additional revenues be collected within 24 months following the end of the annual period in which they are recognized.[69]

When midstream rates are reset for the upcoming calendar year, the new rates will be designed to amortize one-half of the cumulative MCRA deferral balance at the end of each year into the next year's midstream rates. Consistent with past practice, any variances that arise in 2014 through 2018 between the annually forecasted MCRA balances and the actual amounts realized will be subject to deferred interest treatment.

4.2.2 Revenue Stabilization Adjustment Mechanism (RSAM)

FEI is requesting to modify the currently approved three year amortization period for the RSAM to two years. This change is the result of the same US GAAP requirements discussed in relation to the MCRA account. The RSAM captures weather variations in delivery rates, and thus falls within the US GAAP definition of an alternative revenue program.

In order to give effect to this new US GAAP requirement, FEI RSAM account balances would be recovered from or returned to customers through Delivery Rate Rider 5 over a two year period. The determination of FEI's Delivery Rate Rider 5 for 2014 is shown in Section E, Schedule 63. For 2015 through 2018, Rate Rider 5 will be reset each year as part of FEI's annual rate setting process.

[69] To date since the adoption of US GAAP effective January 1, 2012, the MCRA balance has been in a credit balance (has not recorded additional revenues to be collected, but has recorded overcollected revenues), so the issue related to the amortization period has not arisen.

4.2.3 Interest on MCRA and RSAM

Balances in these accounts and variances from the forecast amounts has always been recovered from or returned to customers using the same methodology as for the associated MCRA and RSAM accounts. Therefore, in this Application, the amortization period for MCRA interest and RSAM interest should change from 3 years to 2 years to align with the requested change in amortization periods for the MCRA and RSAM accounts.

4.2.4 Pension and OPEB Variance

FEI is requesting approval to extend the amortization period of this account from the currently approved three year period to the Expected Average Remaining Service Life ("EARSL") of the benefit plans. The EARSL amortization period more appropriately allocates the costs over the future period to which they are applicable. In its most recent accounting valuation done at December 31, 2012, the EARSL for the defined benefit pension plans is 10 years and the EARSL for OPEBs is 15 years. Using the weighted average of the 2014 through 2018 forecasted pension and OPEB expenses, as shown in Table D4-2 below, the average EARSL amortization period is 12 years[70]. This amortization period will be used for the term of this PBR and may be adjusted in the next revenue requirement application based on the calculation of EARSL at that time.

Table D4-2: Weighting of FEI Pension and OPEB expenses

	Pension Expense	OPEB Expense
2014 Forecast	20,004	8,662
2015 Forecast	17,725	8,987
2016 Forecast	16,175	9,316
2017 Forecast	14,741	9,856
2018 Forecast	13,438	12,027
Total	$ 82,083	$ 48,848
Weighting	62.69%	37.31%

4.2.5 Customer Service Variance Account

The Customer Service Variance Account was approved in the 2012-2013 RRA Decision to capture variances in forecast and actual costs resulting from the implementation of the new customer service delivery module, with the amortization period to be determined in the next revenue requirement application of the FEU. The savings accumulated in this account are discussed in Section C3.5.3. FEI is seeking approval to amortize the forecasted 2013 Customer Service Variance account ending balance through delivery rates over five years beginning in

[70] (10 years x 62.69%) + (15 years x 37.31%) = 11.87 years (rounded to 12 years)

2014. FEI believes a five year amortization period is appropriate because it smoothes the rate impacts of the significant credits held in the account over the term of the PBR.

4.2.6 Energy Efficiency and Conservation (EEC)

Pursuant to Commission Order No. G-36-09, the Commission approved the use of separate rate base deferral accounts for EEC expenditures for both FEI and FEVI. Additionally, through Commission Order G-44-12, FEW received approval for a rate base deferral account to capture EEC for expenditures for Whistler customers. The decisions also approved the inclusion of the forecast deferral account balances in rate base on a net-of-tax basis, allocated amongst the FEU on an average customer basis for forecast purposes, and to amortize these balances in rates over a ten year period. The use of the rate base deferral accounts to capture forecast amounts was reaffirmed in Order G-44-12. Additionally, the FEI non-rate base EEC incentive deferral account was approved to capture actual spend above the forecast amount up to the maximum approved funding "envelope".

All EEC costs incurred by FEI continue to be subject to the approved by Commission Orders G-36-09 and G-44-12. FEI is not proposing any change to the approach of using these deferral accounts to manage EEC expenditures, or the financial treatment of the rate base deferral account. The two new requests, which relate to the maximum funding "envelope" and the disposition of the balance in the non-rate base deferral account, are discussed in further detail below.

Decrease to EEC Funding

The FEU are seeking acceptance under section 44.2 of the Act of a EEC funding envelope of $34.4 million for 2014 based on the FEU's 2014-2018 EEC Plan (Appendix I1). This is a decrease from the 2013 approved amount of $35.6 million.[71] The FEU are also seeking acceptance of annual increases to the EEC portfolio from 2015 to 2018, up to $39.0 million in 2018 to reflect EEC program growth. The total forecast amount included in rate base will remain $15 million for the FEU, and the difference between $15 million and the new total funding "envelope" is still to be captured in the non-rate base EEC incentive deferral account on an as-spent basis.

Appendix I provides a review of the proposed EEC activity for 2014 to 2018, and of the EEC-related approvals sought.

Transfer of EEC Incentive Non-Rate Base Deferral Account

FEI is seeking approval to transfer the balance in the non-rate base EEC Incentive deferral account as at December 31, 2013 to the rate base EEC deferral account on January 1, 2014. In

[71] Page 169 of BCUC Order G-44-12 approves EEC funding of $36.2 million for 2013. The amount shown here excludes the $0.6 million approved for High Carbon Fuel Switching recovered as an expense and not through this deferral account.

this Application, FEI has forecasted a transfer of $7.1 million[72] on January 1, 2014. The forecasted amount relates to the actual after-tax 2012 additions to the non-rate base account and accumulated AFUDC on this amount in 2013. No additions have been forecast in the non-rate base account in 2013. The amounts will be amortized over 10 years beginning 2014 in accordance with the existing approved amortization period for the EEC rate base deferral account. Additionally, FEI is seeking approval to transfer any new amounts accumulated in this account, during the 2014 – 2018 revenue requirement period, to the rate base EEC deferral account in the following year, with amortization over 10 years commencing the year in which the balance is transferred.

4.2.7 Biomethane Program Costs

FEI is requesting approval to capture the application costs related to the FEI Biomethane Post Implementation Report and Application for Continuance of Biomethane Program filed December 19, 2012 with the Commission in this existing deferral account. These costs consist of legal fees, intervener and participant funding costs, Commission costs, and miscellaneous facilities, stationery and supplies costs. As of March 2013, FEI has incurred approximately $85 thousand in costs and has forecasted approximately another $50 thousand for the remainder of 2013. As the original amortization period was three years beginning January 1, 2012, FEI will amortize these new additions to this account in 2014 to recover the balance of this account by the end of 2014.

4.2.8 NGV for Transportation Application

In the NGV Application filed on December 1, 2010, and as approved through BCUC Order G-128-11, FEI received approval for a non-rate base deferral account attracting AFUDC to capture the NGV Fuelling Service Application costs incurred in 2010 and 2011 and to recover these costs from all non-bypass customers by transferring the account to rate base and amortizing the balance through delivery rates commencing January 1, 2012 over a three year period. This Order also noted that future individual application costs must be recovered directly from those customers. Any variances between the forecast account balances and the actual incurred costs for the December 1, 2010 Application is being amortized in rates in 2014.

FEI has also included costs in this deferral account in 2012 and 2013 related to the Rate Schedule 16 Application filed September 25, 2012. The inclusion of these costs was requested in the Rate Schedule 16 Application and justified in the related Information Requests. Pursuant to Order G-88-13 received on June 4, 2013, application costs related to Rate 16 will be updated in an evidentiary update to this application once the decision has been fully evaluated. For purposes of determining its 2014 through 2018 revenue requirements, FEI has included these costs in this account and amortized the costs over 3 years beginning 2014.

[72] Section E, Schedule 49, Line 10, Column 3

4.2.9 Generic Cost of Capital Application

On November 28, 2011, the Commission issued a Preliminary Notification of Initiation of Generic Cost of Capital (GCOC) Proceeding to all regulated entities. As approved through BCUC Order G-20-12, the Commission ordered a GCOC Proceeding taking place in two stages. Stage 1 was to review the setting of the appropriate cost of capital for a benchmark low-risk utility, the possible return to an ROE AAM for setting an ROE for the benchmark low-risk utility, and the establishment of a deemed capital structure and deemed cost of capital methodology. As part of the GCOC Stage 1 Proceeding, FEI has incurred application costs related to legal fees, costs for witnesses and consultants, and miscellaneous facilities, stationery and supplies costs. The Commission determined in Order G-47-12, that the Commission's direct costs incurred in this proceeding would not be directly billed, but would be covered through the annual recovery of Commission costs through the annual levies and cost recoveries the utilities pay quarterly.

FEI has also estimated for further costs it anticipates incurring related to Participant Assistance/Cost Award (PACA) reimbursements once the Commission issues its Stage 1 decision. Pursuant to Order G-72-12, the Commission determined that the fairest way to allocate PACA costs, recognizing that all utilities will be affected by this proceeding, is based on the principles established in Order F-5-06, which allocates the PACA awards, once determined, to utilities in this proceeding based on their share of the previous year's total utility sales converted to gigajoules.

The GCOC Stage 2 will apply the generic benchmark utility ROE and capital structure in the determination of an appropriate ROE and capital structure for each affected utility. No Stage 2 proceeding is required for FEI itself.

In this Application, FEI is seeking approval for a rate base deferral account to record the forecast costs related to the GCOC Stage 1 proceeding, less the amounts recovered from other affected utilities. The balance in the rate base deferral account will be allocated to FEVI, FEW and Fort Nelson customers based on the Commission's levy calculation and their share of the previous year's total utility sales converted to gigajoules. FEI proposes to amortize the balance in the account over two years beginning in 2014. This time period is consistent with the direction in Order G-75-13, which stated "FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015".

4.2.10 Amalgamation and Rate Design Application Costs

As part of the Common Rates, Amalgamation and Rate Design Application, FEU incurred costs related to application and hearing-related legal fees, costs for expert witnesses and consultants, intervener and participant funding costs, Commission costs, required public notifications, stakeholder consultation and miscellaneous facilities, stationery and supplies costs. These costs were all captured in a non-rate base deferral account, within FEI, attracting AFUDC as requested in that application. The forecasted balance in this account at the end of 2013, including AFUDC, is approximately $1.7 million dollars. FEI is requesting to continue accumulating residual costs related to that Application, and the subsequent reconsideration application that was filed on April 26, 2013, in this deferral account and to transfer FEI's portion of the accumulated balance to rate base beginning January 1, 2014. The remaining portion will be allocated amongst the FEU on the basis of average customers. The balance in FEI's rate base deferral would then be amortized to its delivery rates over three years beginning in 2014.

4.2.11 Residual Delivery Rate Riders

As approved through Commission Order G-44-12 as part of the 2012-2013 RRA, FEI received approval to combine three residual non-rate base deferral account balances into one account, the Residual Delivery Rate Riders account, and to recover the balance through delivery rates in 2012. The residual balances in the ROE Revenue Requirement Variance Account (Rate Rider 2) and the Lochburn Land Costs and Delivery Rate Refund Rider accounts (both accounts used Rate Rider 4). All three balances have now been fully recovered during the 2012-2013 period with no further amounts remaining to be recovered from or returned to customers in the future.

Rather than discontinue the deferral account, FEI is seeking approval to combine three more residual deferral accounts into this account. The residual balances in the Commodity Unbundling non-rate base deferral account (Rate Rider 8), the Earnings Sharing/Capital Incentive Mechanism rate base deferral account (Rate Rider 3), and the new amount in the Delivery Rate Refund Rider non-rate base deferral account (Rate Rider 4) result from volume variances (the actual volumes for recovery of the riders differed from what was forecast). Approved by Commission Order G-25-04, G-66-05 and C-6-06, delivery Rate Rider 8 captured the costs related to residential and commercial unbundling and recovered them from all non-bypass customers. Approved by Commission Order G-7-03, delivery Rate Rider 3 captured the earnings sharing amounts to be returned to customers during the 2003-2009 PBR period, as well as the calculation of the capital incentive mechanism amount for the 2003-2009 PBR period to be returned to customers. Approved by Commission Order G-44-12 and included in the May 15, 2012 Compliance Filing for the 2012-2013 RRA, delivery Rate Rider 4 captured the revenue variance between the 2012 interim and permanent delivery rates and refunded this amount to customers over a seven month period from June 1, 2012 to December 31, 2012.

The residual balances in these accounts, forecasted to be a credit of $38 thousand at the end of 2013, will be returned to customers in 2014 through the amortization of the Residual Delivery Rate Riders deferral account.

Additionally, as a result of the change to the 2013 ROE and equity structure as approved by Commission Order G-75-13, FEI will capture the amount to be returned to customers and the offsetting rider refunds to customers in the Delivery Rate Refund Rider non-rate base deferral account (Rate Rider 4). To the extent there is a balance remaining in this account at the end of 2013 due to potential volume variances, FEI is seeking approval to transfer this balance to the Residual Delivery Rate Riders account and recover it from or return it to customers in 2015.

The consolidation of these deferral accounts into one account is consistent with the Commission's recognition in the 2012-2013 RRA Decision (at p.125) that "combining three deferral accounts into a single Residual Delivery Rate Riders Deferral Account streamlines the account management of these deferral accounts."

4.3 *INFORMATION UPDATES*

The following section includes information to address past Commission directives and important updated information for various accounts

4.3.1 On-Bill Financing Pilot Program

In accordance with Commission Order G-163-12, FEI created a non-rate base deferral account attracting AFUDC to capture on a net-of-tax basis, the principal loan balances provided to participating customers of the On-Bill Financing (OBF) Pilot Program and the applicable interest charges and recoveries. FEI is seeking approval to transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and to continue to recover the balance from OBF pilot program customers over approximately a ten-year period until the account is fully recovered.

4.3.2 Insurance Variance (and Other Non-Controllable Deferral Accounts)

As requested in the 2012-2013 RRA Decision, the Companies were to re-visit the appropriateness of their existing non-controllable deferral accounts and, specifically, the Insurance Variance deferral account in this Application[73]. Regarding the Insurance Variance account, at this time, FEI continues to believe this account is appropriate. Regardless of the portion of insurance costs that are either within or not within FEI's control, there still remains an element of these costs that are outside the control of the Company. Additionally, the insurance marketplace is very volatile when it comes to estimating premiums year over year as a result of a number of items.

- General market conditions for insurance companies both for investment returns and loss history is unpredictable.
- Impact of large losses on the marketplace for both general overall industry losses and more specific industry losses (e.g. 9-11, Hurricane Sandy, Macondo Gulf of Mexico Oil spill, San Diego Gas & Electric fire fighting expense liability) can have a significant impact on insurance rates anywhere from a 10 percent to 100 percent increase and

[73] 2012-2013 RRA Decision, page 116 "*The Commission Panel has one area of concern with respect to existing non-controllable item deferral accounts. Insurance costs, while having elements that are beyond the Companies' control, such as changes related to economic circumstances and natural disasters, also have elements they can control. These include factors such as changes in deductibles before insurance coverage begins or self insurance for certain assets. Given the current economic circumstances where there is considerable uncertainty on a global scale, the Commission Panel accepts the insurance variance deferral account at this time. The Companies are requested to revisit the appropriateness of the non-controllable deferral accounts at the time of their next revenue requirements application.*"

potentially more. The market may even react by excluding coverage altogether (i.e. terrorism, poles and wires).

- Insurers are becoming more sensitive to catastrophic risks such as earthquake, hurricane and forest fire losses and, therefore, companies exposed to these types of losses will have continued scrutiny on premiums.

To mitigate the risks of these types of costs on the customer and the shareholder, it is appropriate to use deferral accounts to capture these types of variances to ensure the costs are fully borne by the appropriate parties. Further, in the 2012-2013 RRA Decision, the Commission pointed out that this deferral account was appropriate due to the considerable uncertainty of the current economic circumstances on a global scale. Global market uncertainty remains, and this deferral account is still required to mitigate the circumstances.

The historical annual additions to this account have been credits, amounts to be refunded to customers, in every year with the exception of 2012. These credits have averaged approximately $660 thousand per year since 2004 with the 2012 debit approximately $60 thousand. The fluctuation in the size of the variances also illustrates the difficulty in forecasting accurately.

For the other non-controllable deferral accounts, FEI currently has existing accounts for the following expense items:

- Property Taxes variances
- Pension & OPEB expense variances
- BCUC Levies variances
- Interest variances
- Tax variances
- Customer Service Costs variances (2012 & 2013 only)

The accounts above were created to capture variances between amounts approved in customer rates and actual costs, which are primarily or entirely associated with rates that are set by outside authorities (property tax rates, income tax rates, BCUC levies) or with market driven factors, as is the case with pension and OPEB expenses and interest rates. These accounts mitigate customer and shareholder risk in the case of unforeseen cost increases or savings achieved and serve to ensure costs are fully borne by the appropriate parties. FEI believes these accounts continue to serve their purpose, that the non-controllable nature of the items recorded in the accounts has not changed, and that they should continue to exist.

4.3.3 Gas Asset Records Project

This deferral account was created to capture the costs that will allow the Company to continue to meet the records management requirements of the codes, regulations and standards that govern our business, and approved by Commission Order G-44-12.

The Gas Asset Records Project is progressing well. There have been challenges in attracting experienced technical staff from the current labour market, resulting in a longer ramp-up time for the project than first anticipated. The completion of this project is expected to extend from 2015 to 2017; however, the forecasted overall budget of $7.8 million remains the same as the previous amount included in the 2012-2013 RRA. The table below summarizes the costs associated with the Gas Asset Records Project, which are allocated among the FEU. FEI's allocated portion of the amounts in the table below are included in the financial schedules[74] of this Application.

Table D4-3: FEU Gas Assets Records Project Costs ($ thousands)

	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	Total
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	280	800	800	800	800	300	3,780
Project 'B' – Implement improved drawing management & control systems		70	150	150			370
Project 'C' - Review & analyze historical drawings	30	220	300	650	1050	1,400	3,650
Total	310	1,090	1,250	1,600	1,850	1,700	7,800

The $7.8 million amount shown in the table above is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers. Further, the additions to this account are allocated amongst the FEU on the basis of average customers. Forecasted additions to this account are amortized in rates over five years with any variances from amounts forecast amortized in rates beginning the following year.

4.3.4 BCOneCall Project

A deferral account to capture the O&M costs related to the BCOneCall Project was approved by Commission Order G-44-12 for FEI. This project is intended to improve efficiency and reduce

[74] 2014 additions are shown in Section E, Schedule 50, Line 11, Column 4.

operating costs for FEI's Public Underground Location Services department by improving data consistency and enabling further process automation.

The Project involves several "streams". With the completion of the Technology Stream, this project has delivered a significant financial benefit that has reduced the long term O&M costs required for processing BC One Call tickets by approximately $600 thousand per year. The increased benefit is attributable to a higher than expected reduction in ticket processing time. Further benefits are expected as the Data Consistency and Conflation Streams are completed.

The Technology Stream was completed on schedule and the Conflation Stream is on track to be completed in 2014 as planned. The completion of the Data Consistency Stream has been extended from 2014 to 2017 to take advantage of resource synergies with the Conflation Stream. When the Conflation Stream is complete, resources will be redeployed to the Data Consistency Stream. The forecasted overall FEU budget of $2.3 million remains the same as the amount included in the 2012-2013 RRA and is provided in the table below.

Table D4-4: FEU BCOneCall Ticket Process Improvement Project Costs ($ thousands)

Stream	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	Total
Data Consistency Stream	20	380	450	150	150	120	1,270
Conflation Stream	130	700	200				1,030
Total	**150**	**1080**	**650**	**150**	**150**	**120**	**2,300**

The $2.3 million amount shown in the table above is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers. Further, the additions to this account are allocated amongst the FEU on the basis of average customers. Forecasted additions to this account are amortized in rates over five years with any variances from amounts forecast amortized in rates beginning the following year.

4.3.5 Compliance with Emissions Regulations

The Compliance with Emissions Regulations Deferral Account, approved by Commission Order G-44-12, captures potential compliance costs and revenues collected from the sale of carbon credits. The account was implemented to capture the growing number of regulations around emissions trading that may result in incremental compliance costs and recoveries during the forecast period. These compliance costs and recoveries are difficult to forecast because of uncertainty around the final form and applicability of emissions trading regulations. Currently, the potential Emissions Trading Regulation (under the *Greenhouse Gas Reduction (Cap and Trade) Act*), the Carbon Neutral Government Regulation and the Emission Offsets Regulation (both brought into force under the *Greenhouse Gas Reduction Targets Act*) and the Renewable

and Low Carbon Fuel Requirements Regulation (RLCFRR) are two regulatory mechanisms aimed to reduce Greenhouse Gas (GHG) emissions in BC. These regulations, as discussed further below, could impact us in three ways: 1) we could be required to hold allowances or offsets against our own operating emissions under Cap and Trade, 2) we could be required to hold credits equal to our compliance obligation under the RLCFRR and 3) we could sell our credits from customer offerings that result in in GHG reduction projects (offsets), over-performance under the RLCFRR, or from selling allowances or offsets that are surplus to requirements under a potential future Cap and Trade regime.
The Emissions Trading Regulation, which has been discussed with partners in the Western Climate Initiative, was initially proposed to start in 2012, but has not been brought into force in BC[75]. Although BC still remains a partner with Western Climate Initiative, there has been no further action with respect to a cap-and-trade legislative model. The timing and implementation of cap and trade will continue to be driven by the political landscape in BC. Therefore, whether a cap-and-trade system comes into play at a national, regional, or provincial level in the future is still unknown at this time and the utilities' requirement to comply with such requirements is yet to be determined.

The Province of BC has also legislated the RLCFRR, which addresses the transportation sector's contribution to GHG emissions in BC. Starting on July 1, 2013, Part 3 fuel suppliers will have to meet annual targets, or pay a penalty. Natural gas, propane, electricity and hydrogen are Part 3 fuels if they are sold for use in transportation. *"A Part 2 or Part 3 fuel supplier who manufactures fuel in British Columbia for the first time or imports fuel into British Columbia for the first time, or uses it for the first time, is responsible for compliance unless there is a written agreement stating otherwise."*

Since we sell natural gas for transportation under various rate classes, we have the opportunity to claim first sale as a 'Part 3' fuel supplier in the Province.[76] This regulation allows for generation of low carbon compliance credits based on required carbon intensity baseline. Those suppliers who are not in compliance with the mandated reductions in carbon will have to purchase credits from others or pay a penalty of $200/tonne for deficiencies. As we add more CNG and LNG sales, our credits will increase as they are measured against the conventional fuel intensity baseline, which creates a potential revenue stream for FEI, benefiting our customers through this deferral account mechanism.

As an early step in realizing the economic value of GHG emission reductions as carbon offsets, FEI has explored opportunities to sell carbon offsets from the Efficient Boiler Program for commercial customers in its EEC initiative. FEI currently contracts for the ownership of any carbon credits realized as part of its natural gas EEC programs, thereby potentially enabling FEI to monetize these GHG reductions as offsets with a market value. Monetizaton of offsets from

[75] California started this regime in 2013 and Quebec is scheduled to start in 2014.
[76] FEI is awaiting further clarification from the Ministry regarding the definition of Part 3 fuel suppliers as it relates to natural gas for transportation.

utility EEC programs, however, has not yet been done in BC because a protocol has only just been established that allowed for the quantification and aggregation of emission reductions in projects, and such a project will be subject to third-party validation and verification. Additionally, there is uncertainty around the structure and role the Pacific Carbon Trust will play in BC in the near future. If these revenues materialize FEI would flow these revenues back to customers through this account.

As a result of the above-mentioned concerns and uncertainties, it is difficult to forecast costs and revenues associated with carbon credits, cap and trade and RLCFRR regulations. Therefore, for purposes of the 2014 through 2018 PBR Period, additions to this account have not been forecast at this time and the amortization of any balance that accumulates in this account will be addressed in a future rate setting process.

4.4 ACCOUNTS TO BE DISCONTINUED

4.4.1 Depreciation Variance

The Depreciation Variance deferral account was in place for two years only (2012 and 2013) as approved through Commission Order G-44-12:

> *"The Commission Panel directs that a deferral account be established to capture the variances between forecast depreciation and actual depreciation in the test period as well as the directly attributable variance between forecast tax impacts and actual tax impacts for the test period only."*

FEI will amortize the forecasted 2013 ending balance of this account in 2014.

As this account was only in place for two years, with its discontinuation, FEI is proposing to return to the practice of depreciating assets at the beginning of the year after which the assets are placed in service. This is a return to the treatment FEI used during its last PBR, from 2004 through 2009. Under the present PBR, and as discussed in Section B of this Application, the incentive to find efficiency savings in capital is a key component of the PBR Plan design, and is present in PBR plans that incorporate capital as part of the formula, and supported by PBR theory for both rate cap and revenue cap type models. In FEI's PBR Plan proposal, the capital incentive is made up of three components – earned return, depreciation and taxes. A depreciation variance deferral account would take away all of the incentive related to capital with the exception of the small earned return component. With depreciation expense commencing in the year following when the assets are placed in service, the variance in depreciation expense from year to year will be driven by the formula vs. actual capital spending from prior years.

To summarize, FEI believes it is appropriate for FEI to return to the previously approved PBR method relating to depreciation, which is allowed under US GAAP and achieves same the objective as the depreciation variance deferral account in that it minimizes any variances in depreciation expense related to the timing or amount of capital being placed in service as compared to forecast.

4.4.2 Southern Crossing Pipeline Tax Reassessment

The Southern Crossing Pipeline Tax Reassessment account was approved by Commission Orders G-160-06 and G-153-07 and captured the 2007 PST reassessment by the Province for the SCP project. Further, the Commission's 2012-2013 RRA Decision (Order G-44-12) approved the use of this account to also capture another reassessment from the Province related to the lease payments made by the Company in respect of pipe and compressor assets of the SCP.

The Company appealed both of these reassessments and received a decision in the Company's favour. The original reassessment amounts, including interest, were returned to the Company and reduced the balance in this account. The total forecasted amount in this account on an after-tax basis, which includes legal and consulting fees related to this matter, is a credit of $32 thousand at the end of 2013.

In this Application, FEI is seeking approval to amortize this amount in customer rates over a one-year period beginning January 1, 2014 and then discontinue the use of this deferral account.

4.4.3 Tilbury Property Purchase (Subdividable Land)

Approved by Commission Order G-68-10, the Tilbury Property Purchase deferral account captured the original allocation of the subdividable area of land ($3.3 million) plus interest.

As discussed in the FEI Tilbury Land Sale Application dated October 12, 2011 and approved through Commission Order G-181-11, FEI has subsequently sold this land and recorded the proceeds of sale against the balance of this deferral account. Additionally, as discussed in that Application, FEI has also recorded incremental rental revenue from the property over and above what was forecast in the 2012-2013 RRA.

After accounting for the above items, the net forecasted balance at the end of 2013 is a credit balance, to be returned to customers, of $164 thousand.

In this Application, FEI is seeking approval to amortize the forecasted ending 2013 residual balance in delivery rates over 1 year, beginning January 1, 2014. Any variance between the 2013 forecasted amount and actual amount will be amortized in 2015 and then the account will be discontinued.

4.4.4 CNG and LNG Recoveries

The CNG and LNG Recoveries Deferral Account, approved by BCUC Order G-128-11, captured the incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand amounts embedded in the 2012 and 2013 revenue requirements. Effective January 1, 2014, given all stations are accounted for in a separate class of service, excess recoveries will be captured in the NGT classes of service and this account will be discontinued. For 2013, FEI has forecast credit additions of $22 thousand to be returned to non-bypass customers for Rate Schedule 16[77] costs and revenues for that calendar year.

FEI will amortize the forecasted ending 2013 residual balance in delivery rates over 1 year, beginning January 1, 2014. Any variances between the 2013 forecasted amount and actual amount will be amortized in 2015.

4.4.5 BFI Costs and Recoveries

In accordance with Commission Orders C-6-12 and G-150-12, FEI is to capture incremental CNG Service recoveries received from BFI for actual volumes purchased in excess of minimum take or pay commitments in a rate base deferral account, for disposition to be determined at a future date.

Given that BFI is now in a separate class of service, FEI is requesting to discontinue the use of this account and will expense the account effective January 1, 2014 into that class of service. All deficiencies or surpluses related to BFI will be accounted for in the Non-GGRR CNG Class of Service[78] and not FEI's traditional natural gas ratepayers' class of service.

4.4.6 Overhead and Marketing Recoveries from NGT Class of Service

Pursuant to Commission Order G-78-13, this account will capture the recovery of the NGT related portion of overall FEI overhead and marketing costs from NGT customers. This deferral account is non-rate base for the years 2012 and 2013 and FEI forecasts the balance of the account to be a $189 thousand credit at December 31, 2013. This amount will be transferred to rate base effective January 1, 2014 and amortized into non bypass customers' rates commencing January 1, 2014. In this Application, FEI is requesting approval to amortize the balance of this account over a one-year period. To the extent there is a variance between the 2013 forecasted and actual account additions, this difference would be amortized in 2015 and then the account will be discontinued. FEI will forecast the overhead and marketing recovery costs for 2014 forward in the Other Revenues line.

[77] Pursuant to Order G-88-13 received on June 4, 2013, Costs and Recoveries related to Rate 16 will be updated in an evidentiary update to this application once the decision has been fully evaluated

[78] Appendix H.

4.4.7 Other

A number of deferral accounts were created for specific purposes during the term of the last RRA and previous PBR periods that are expected to have no remaining balance or to be fully amortized by December 31, 2014. FEI will be discontinuing the use of the following deferral accounts once there is no remaining balance in the account. The total forecasted balance at the end of 2013 for all the accounts below is approximately a $1.033 million debit to be collected from customers.

- 2011 CNG and LNG Service Costs and Recoveries
- Olympic Security Costs
- IFRS Implementation Costs
- 2009 ROE and Cost of Capital Application
- 2010-2011 Revenue Requirement Application
- 2012-2013 Revenue Requirement Application
- CCE CPCN Application
- Deferred Removal Costs
- US GAAP Conversion Costs
- US GAAP Transitional Costs
- Mark to Market – Customer Care Enhancement Project

4.5 *SUMMARY OF APPROVALS SOUGHT RE DEFERRAL ACCOUNTS*

The Commission has indicated in the Decision accompanying Order No. G-7-03 that its Orders supporting deferral accounts continue in force until a change is approved by the Commission. FEI will continue to use existing deferral accounts as approved, except as articulated in this Application. FEI is requesting approval for two new rate base deferral accounts, the setting of, or modification to, the amortization period or contents of eight rate base deferral accounts, as well as the discontinuation of sixteen deferral accounts. Table D4-5 provides a summary of the request for approvals in this Application related to all rate base deferral accounts.

Table D4-5: Summary of Deferral Account Requests

Type Of Change	Account	Company	Reference
New Account	2014 - 2018 PBR Application Costs	FEI	Section D4.1.1; amortization period of 5 years commencing January 1, 2014
	TESDA Overhead Allocation Variance	FEI	Section D4.1.2; disposition of account will be addressed in 2014 Annual Review
Amortization Period Change -	Midstream Cost Reconciliation Account	FEI	Section D4.2.1; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014

Type Of Change	Account	Company	Reference
New or Modified	Revenue Stabilization Adjustment Mechanism	FEI	Section D4.2.2; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Pension and OPEB Variance	FEI	Section D4.2.4; change from 3 year amortization period to a 12 year amortization period (EARSL), commencing January 1, 2014
	Customer Service Variance Account	FEI	Section D4.2.5; 5 year amortization period, commencing January 1, 2014
Other	Energy Efficiency and Conservation	FEU	Section D4.2.6 1. An decrease from $35.6 million (the approved FEU funding envelope in 2013) to a total of $34.4 million in 2014 and and then an increase to the portfolio in 2015 through 2018 up to $39.0 million in 2018 for Mainland FEI, Vancouver Island and Whistler combined; 2. The continuation of the FEI EEC Incentive non-rate base deferral account attracting AFUDC, approved by Commission Order G-44-12, to capture the actual as spent costs above the amount forecast in rates, up to the approved funding envelope, for 2014 through 2018, and to transfer the FEI portion of the balance to the FEIEEC rate base deferral account in the following year and recover the amount transferred over a ten year period beginning the year in which the balance is transferred. Additionally, FEI is seeking to transfer the FEI portion of the balance in this deferral as at December 31, 2013 to the FEI rate base EEC deferral account and to amortize the amounts in rates over 10 years beginning in 2014
	Biomethane Program Costs	FEI	Section D4.2.7; inclusion of application costs related to the FEI Biomethane Post Implementation Report
	NGV for Transportation Application	FEI	Section D4.2.8; inclusion of Rate Schedule 16 application costs[79]
	Generic Cost of Capital Application Costs	FEI	Section D4.2.9; amortization period of 2 years commencing January 1, 2014
	Amalgamation and Rate Design Application Costs	FEI	Section D4.2.10; transfer FEI's portion of the balance to rate base January 1, 2014, amortization of 3 years commencing January 1, 2014
	Residual Delivery Rate Riders	FEI	Section D4.2.11; inclusion of new residual balances for Rate Riders 3, 4 and 8
	On-Bill Financing Pilot Program	FEI	Section D4.3.1; transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and continue to recover the balance from OBF pilot program customers over approximately a ten year period until the account is fully recovered.

[79] Pursuant to Commission Order G-88-13 received on June 4, 2013, Rate Schedule 16 Application Costs will be addressed through an Evidentiary Update to this Application once the Rate Schedule 16 Decision has been fully evaluated

Type Of Change	Account	Company	Reference
Discontinuance	Southern Crossing Pipeline Tax Reassessment	FEI	Section D4.4.2; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015
	Tilbury Property Purchase (Subdividable Land)	FEI	Section D4.4.3; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016
	CNG and LNG Recoveries	FEI	Section D4.4.4; discontinuation of this account effective January 1, 2015
	BFI Costs and Recoveries	FEI	Section D4.4.5; discontinuation of this account effective January 1, 2014
	Overhead and Marketing Recoveries from NGT Class of Service	FEI	Section D4.4.6; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	2011 CNG and LNG Service Costs and Recoveries	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Olympic Security Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	IFRS Implementation Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2009 ROE and Cost of Capital Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2010-2011 Revenue Requirement Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2012-2013 Revenue Requirement Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	CCE CPCN Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Deferred Removal Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	US GAAP Conversion Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	US GAAP Transitional Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Mark to Market - Customer Care Enhancement Project	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2014

1 # E: FINANCIAL SCHEDULES – 2014 DELIVERY RATES

Line No.	Particulars	2014 ($ Millions)		Cross Reference
1	(1)	(2)		(3)
2	Volume/Revenue Related			
3	Customer Growth and Use Rates	(10.8)		
4	Change in Other Revenue	1.2	(9.6)	
5				
6	O&M Changes			
7	Gross O&M Increases	(0.8)		
8	Less: Capitalized Overhead	0.1	(0.7)	
9				
10	Depreciation Expense			
11	Change in Depreciation Rates	(0.1)		
12	Tax Expense Impact of Depreciation Changes	0.3		
13	Depreciation from Net Additions	1.0	1.2	
14				
15	Amortization Expense			
16	CIAC	0.2		
17	Deferral Accounts	4.6	4.8	
18				
19	Other			
20	Property and Other Taxes	(2.4)		
21	Income Tax Rate Change	-		
22	Other Income Tax Changes	8.5		
23	Financing Rate Changes	(11.3)		
24	Financing Changes	(2.2)		
25	Rate Base Growth	1.0	(6.4)	
26				
27	**Revenue Deficiency (Surplus)**		**(10.6)**	- Section E-FORMULA, Sch 2
28				

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Non-Bypass Sales	2014 Non-Bypass Transportation	2014 Bypass and Special Rates	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,128,389	$ 1,030,748	$ 84,964	$ 11,524	$ 1,127,236	$ (1,153)	- Section E-FORMULA, Sch 8
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,237	-	-	18,138	18,138	(99)	- Section E-FORMULA, Sch 13
8								
9	Total Revenue	1,146,626	1,030,748	84,964	29,662	1,145,374	(1,252)	
10								
11	Less - Cost of Gas	(505,695)	(499,187)	(250)	(248)	(499,685)	6,010	- Section E-FORMULA, Sch 9
12								
13	Gross Margin	$ 640,931	$ 531,561	$ 84,714	$ 29,414	$ 645,689	$ 4,758	
14								
15	Revenue Deficiency (Surplus)	$ -	$ (9,153)	$ (1,459)	$ -	**$ (10,612)**	$ (10,612)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	-1.72%	-1.72%	0.00%	-1.64%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	-0.89%	-1.72%	0.00%	-0.93%		
20								

FORTISBC ENERGY INC. June 10, 2013 Section E FORMULA Schedule 3

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	ENERGY VOLUMES (TJ)					
2	Sales	113,621	112,327	113,946	1,619	- Section E-FORMULA, Sch 5
3	Transportation	86,767	94,833	97,857	3,024	- Section E-FORMULA, Sch 5
4		200,388	207,160	211,803	4,643	
5						
6	Average Rate per GJ					
7	Sales	$ 9.106	$ 10.538	$ 9.052	$ (1.486)	
8	Transportation	$ 1.039	$ 0.966	$ 0.991	$ 0.025	
9	Average	$ 5.616	$ 6.156	$ 5.296	$ (0.860)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 1,034,629	$ 1,133,062	$ 1,031,439	$ (101,623)	- Section E-FORMULA, Sch 7
13	- Increase / (Decrease)	-	50,679	-	(50,679)	
14	RSAM Revenue	472	-	(6,666)	(6,666)	
15	Transportation - Existing Rates	90,183	83,945	96,951	13,006	- Section E-FORMULA, Sch 7
16	- Increase / (Decrease)	-	7,660	-	(7,660)	
17						
18	**Total Revenue**	1,125,284	1,275,346	1,121,724	(153,622)	
19						
20	Cost of Gas Sold (Including Gas Lost)	539,821	658,568	505,695	(152,873)	- Section E-FORMULA, Sch 9
21						
22	**Gross Margin**	585,463	616,778	616,029	(749)	
23						
24	Operation and Maintenance	187,925	202,963	198,578	(4,385)	- Section E-FORMULA, Sch 15
25	Property and Sundry Taxes	49,656	51,239	51,239	-	- Section E-FORMULA, Sch 19
26	Depreciation and Amortization	123,928	142,912	142,912	-	- Section E-FORMULA, Sch 21
27	Other Operating Revenue	(24,501)	(24,789)	(23,204)	1,585	- Section E-FORMULA, Sch 12
28	Sub-total	337,008	372,325	369,525	(2,800)	
29	Utility Income Before Income Taxes	248,454	244,453	246,504	2,051	
30						
31	Income Taxes	26,880	28,049	27,508	(541)	- Section E-FORMULA, Sch 23
32						
33	**EARNED RETURN**	$ 221,574	$ 216,404	$ 218,996	$ 2,592	- Section E-FORMULA, Sch 59
34						
35						
36	**UTILITY RATE BASE**	$ 2,692,824	$ 2,767,988	$ 2,701,542	$ (66,446)	- Section E-FORMULA, Sch 29
37						
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.23%	7.82%	8.11%	0.29%	- Section E-FORMULA, Sch 59

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars (1)	2013 PROJECTED (2)	2014 FORECAST Existing 2013 Rates (3)	Revised Revenue (4)	Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	113,946	114,985	-	114,985	1,039	- Section E-FORMULA, Sch 6
3	Transportation	97,857	98,582	-	98,582	725	- Section E-FORMULA, Sch 6
4		211,803	213,567	-	213,567	1,764	
5							
6	Average Rate per GJ						
7	Sales	$ 9.052	$ 8.964	$ -	$ 8.885	$ (0.167)	
8	Transportation	$ 0.991	$ 0.979	$ -	$ 0.964	$ (0.027)	
9	Average	$ 5.296	$ 5.278	$ -	$ 5.228	$ (0.068)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,031,439	$ 1,030,748	$ -	$ 1,030,748	$ (691)	- Section E-FORMULA, Sch 8
13	- Increase / (Decrease)	-	-	(9,154)	(9,154)	(9,154)	- Section E-FORMULA, Sch 10
14	RSAM Revenue	(6,666)				6,666	
15	Transportation - Existing Rates	96,951	96,488	-	96,488	(463)	- Section E-FORMULA, Sch 8
16	- Increase / (Decrease)	-		(1,458)	(1,458)	(1,458)	- Section E-FORMULA, Sch 10
17							
18	**Total Revenue**	1,121,724	1,127,236	(10,612)	1,116,624	(5,100)	
19							
20	Cost of Gas Sold (Including Gas Lost)	505,695	499,685	-	499,685	(6,010)	- Section E-FORMULA, Sch 9
21							
22	**Gross Margin**	616,029	627,551	(10,612)	616,939	910	
23							
24	Operation and Maintenance	198,578	202,307	-	202,307	3,729	- Section E-FORMULA, Sch 15
25	Property and Sundry Taxes	51,239	48,797	-	48,797	(2,442)	- Section E-FORMULA, Sch 20
26	Depreciation and Amortization	142,912	148,655	-	148,655	5,743	- Section E-FORMULA, Sch 22
27	Other Operating Revenue	(23,204)	(23,616)	-	(23,616)	(412)	- Section E-FORMULA, Sch 13
28	Sub-total	369,525	376,143	-	376,143	6,618	
29	Utility Income Before Income Taxes	246,504	251,408	(10,612)	240,796	(5,708)	
30							
31	Income Taxes	27,508	39,481	(2,653)	36,828	9,320	- Section E-FORMULA, Sch 24
32							
33	**EARNED RETURN**	$ 218,996	$ 211,927	$ (7,959)	$ 203,968	$ (15,028)	- Section E-FORMULA, Sch 60
34							
35							
36	**UTILITY RATE BASE**	$ 2,701,542	$ 2,798,625	$ (28)	$ 2,798,597	$ 97,055	- Section E-FORMULA, Sch 30
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.11%	7.57%		7.29%	-0.82%	- Section E-FORMULA, Sch 60

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Projected Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	69,753.0	69,816.4	69,644.2	-	69,644.2	(172.2)	
3	Schedule 2 - Small Commercial	24,319.0	23,331.9	24,087.6		24,087.6	755.7	
4	Schedule 3 - Large Commercial	16,744.0	16,514.8	17,354.8		17,354.8	840.0	
5								
6	Schedules 1, 2 and 3	110,816.0	109,663.1	111,086.6	-	111,086.6	1,423.5	
7								
8	Schedule 4 - Seasonal	169.0	185.2	169.1		169.1	(16.1)	
9	Schedule 5 - General Firm	2,315.0	2,407.7	2,315.3		2,315.3	(92.4)	
10								
11	Industrials							
12	Schedule 7 - Interruptible	87.0	14.2	86.7		86.7	72.5	
13								
14	Schedule 6 - N G V Fuel - Stations	62.0	56.4	61.4		61.4	5.0	
15	Schedule 16 - Liquefied Natural Gas (LNG)	172.0	-	226.5		226.5	226.5	
16	Total Sales	113,621.0	112,326.6	113,945.6	-	113,945.6	1,619.0	- Section E-FORMULA, Sch 3
17								
18	**TRANSPORTATION SERVICE**							
19	Schedule 22 - Firm Service	18,884.0	17,089.5	13,208.0	6,874.9	20,082.9	2,993.4	
20	- Interruptible Service	18,760.0	12,302.6	15,940.9	-	15,940.9	3,638.3	
21	Byron Creek (aka Fording Coal Mountain)	393.0	227.4		179.1	179.1	(48.3)	
22	Burrard Thermal - Firm	482.0	1,372.0		482.5	482.5	(889.5)	
23	FEVI - Firm	21,244.0	37,080.0		33,553.2	33,553.2	(3,526.8)	
24	Schedule 23 - Large Commercial	7,803.0	7,485.3	8,168.1		8,168.1	682.8	
25	Schedule 25 - Firm Service	12,829.0	13,471.3	12,288.4	837.3	13,125.7	(345.6)	
26	Schedule 27 - Interruptible Service	6,372.0	5,804.8	6,324.5		6,324.5	519.7	
27								
28	Total Transportation Service	86,767.0	94,832.9	55,929.9	41,927.0	97,856.9	3,024.0	- Section E-FORMULA, Sch 3
29								
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,388.0	207,160.0	169,875.5	41,927.0	211,802.5	4,643.0	- Section E-FORMULA, Sch 3
31								

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2014

Line No.	Particulars	2013 PROJECTED	2014 Forecast Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	69,644.2	69,511.7	-	69,511.7	(132.5)	
3	Schedule 2 - Small Commercial	24,087.6	24,246.8		24,246.8	159.2	
4	Schedule 3 - Large Commercial	17,354.8	17,253.0		17,253.0	(101.8)	
5							
6	Schedules 1, 2 and 3	111,086.6	111,011.5	-	111,011.5	(75.1)	
7							
8	Schedule 4 - Seasonal	169.1	169.1		169.1	-	
9	Schedule 5 - General Firm	2,315.3	2,315.3		2,315.3	-	
10							
11	Industrials						
12	Schedule 7 - Interruptible	86.7	86.7		86.7	-	
13							
14	Schedule 6 - N G V Fuel - Stations	61.4	61.4		61.4	-	
15	Schedule 16 - Liquefied Natural Gas (LNG)	226.5	1,341.3		1,341.3	1,114.8	
16	Total Sales	113,945.6	114,985.3	-	114,985.3	1,039.7	- Section E-FORMULA, Sch 4
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	20,082.9	13,188.4	6,553.2	19,741.6	(341.3)	
20	- Interruptible Service	15,940.9	15,822.0	-	15,822.0	(118.9)	
21	Byron Creek (aka Fording Coal Mountain)	179.1		176.6	176.6	(2.5)	
22	Burrard Thermal - Firm	482.5		482.5	482.5	-	
23	FEVI - Firm	33,553.2		33,720.0	33,720.0	166.8	
24	Schedule 23 - Large Commercial	8,168.1	8,721.3		8,721.3	553.2	
25	Schedule 25 - Firm Service	13,125.7	12,604.4	837.3	13,441.7	316.0	
26	Schedule 27 - Interruptible Service	6,324.5	6,476.3		6,476.3	151.8	
27							
28	Total Transportation Service	97,856.9	56,812.4	41,769.6	98,582.0	725.1	- Section E-FORMULA, Sch 4
29							
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	211,802.5	171,797.7	41,769.6	213,567.3	1,764.8	- Section E-FORMULA, Sch 4
31							- Section E-FORMULA, Sch 11

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	**SALES**							
2	Schedule 1 - Residential	$ 684,879	$ 750,275	$ 681,094	$ -	$ 681,094	$ (69,181)	
3	Schedule 2 - Small Commercial	207,547	222,969	206,458		206,458	(16,511)	
4	Schedule 3 - Large Commercial	123,547	139,001	125,680		125,680	(13,321)	
5	Schedules 1, 2 and 3	1,015,973	1,112,245	1,013,232	-	1,013,232	(99,013)	
6								
7	Schedule 4 - Seasonal	945	1,263	946	-	946	(317)	
8	Schedule 5 - General Firm	15,405	18,921	14,624		14,624	(4,297)	
9		16,350	20,184	15,570	-	15,570	(4,614)	
10	Industrials							
11	Schedule 7 - Interruptible	489	133	459	-	459	326	
12								
13	Schedule 6 - N G V Fuel - Stations	480	500	467		467	(33)	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,337	-	1,711		1,711	1,711	
15	Total Sales	1,034,629	1,133,062	1,031,439	-	1,031,439	(101,623)	- Section E-FORMULA, Sch 3
16								
17	**Transportation Service**							
18	Schedule 22 - Firm Service	7,173	8,837	10,521	823	11,344	2,507	
19	- Interruptible Service	17,350	11,101	15,087	-	15,087	3,986	
20	Byron Creek (aka Fording Coal Mountain)	78	55		32	32	(23)	
21	Burrard Thermal - Firm	9,965	9,996		9,965	9,965	(31)	
22	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch12)	-	-		-	-	-	
23	Schedule 23 - Large Commercial	22,810	21,153	25,171	-	25,171	4,018	
24	Schedule 25 - Firm Service	24,484	25,413	25,909	704	26,613	1,200	
25	Schedule 27 - Interruptible Service	8,323	7,390	8,739	-	8,739	1,349	
26	Total Transportation Service	90,183	83,945	85,427	11,524	96,951	13,006	- Section E-FORMULA, Sch 3
27								
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,124,812	$ 1,217,007	$ 1,116,866	$ 11,524	$ 1,128,390	$ (88,617)	- Section E-FORMULA, Sch 3

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 681,094	$ 676,106	$ -	$ 676,106	$ (4,988)	
3	Schedule 2 - Small Commercial	206,458	204,130		204,130	(2,328)	
4	Schedule 3 - Large Commercial	125,680	123,215		123,215	(2,465)	
5	Schedules 1, 2 and 3	1,013,232	1,003,451	-	1,003,451	(9,781)	
6							
7	Schedule 4 - Seasonal	946	946	-	946	-	
8	Schedule 5 - General Firm	14,624	14,624		14,624	-	
9		15,570	15,570	-	15,570	-	
10	Industrials						
11	Schedule 7 - Interruptible	459	459	-	459	-	
12							
13	Schedule 6 - N G V Fuel - Stations	467	467		467	-	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,711	10,801		10,801	9,090	
15	Total Sales	1,031,439	1,030,748	-	1,030,748	(691)	- Section E-FORMULA, Sch 4
16							
17	**Transportation Service**						
18	Schedule 22 - Firm Service	11,344	8,396	823	9,219	(2,125)	
19	- Interruptible Service	15,087	14,740	-	14,740	(347)	
20	Byron Creek (aka Fording Coal Mountain)	32		32	32	-	
21	Burrard Thermal - Firm	9,965		9,965	9,965	-	
22	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch13)	-		-	-	-	
23	Schedule 23 - Large Commercial	25,171	26,766	-	26,766	1,595	
24	Schedule 25 - Firm Service	26,613	26,140	704	26,844	231	
25	Schedule 27 - Interruptible Service	8,739	8,922	-	8,922	183	
26	Total Transportation Service	96,951	84,964	11,524	96,488	(463)	- Section E-FORMULA, Sch 4
27							
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,128,390	$ 1,115,712	$ 11,524	$ 1,127,236	$ (1,154)	- Section E-FORMULA, Sch 4 - Section E-FORMULA, Sch 11

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Projected Gas Costs Non-Bypass Sales & Transp	2013 Projected Gas Costs Bypass and Special Rates	2013 Projected Gas Costs Total	2014 Forecast Gas Costs Non-Bypass Sales & Transp	2014 Forecast Gas Costs Bypass and Special Rates	2014 Forecast Gas Costs Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	310,537	$ -	$ 310,537	$ 305,432	$ -	$ 305,432
3	Schedule 2 - Small Commercial	110,811		110,811	107,890		107,890
4	Schedule 3 - Large Commercial	72,872		72,872	70,770		70,770
5							
6	Schedules 1, 2 and 3	494,220	-	494,220	484,092	-	484,092
7							
8	Schedule 4 - Seasonal	629		629	629		629
9	Schedule 5 - General Firm	8,660		8,660	8,660		8,660
10							
11	Schedules 4 and 5	9,289	-	9,289	9,289	-	9,289
12							
13	Industrials						
14	Schedule 7 - Interruptible	323		323	323		323
15							
16	Schedule 6 - N G V Fuel - Stations	208		208	208		208
17	Schedule 16 - Liquefied Natural Gas (LNG)	778		778	5,275		5,275
18							
19	Total Sales	504,818	-	504,818	499,187	-	499,187
20							
21	**TRANSPORTATION SERVICE**						
22	Schedule 22 - Firm Service	268	58	326	44	31	75
23	- Interruptible Service	58	-	58	73	-	73
24	Byron Creek (aka Fording Coal Mountain)		7	7		-	-
25	Burrard Thermal - Firm		5	5		3	3
26	FEVI - Firm		324	324		210	210
27	Schedule 23 - Large Commercial	41	-	41	43	-	43
28	Schedule 25 - Firm Service	71	6	77	59	4	63
29	Schedule 27 - Interruptible Service	39	-	39	31	-	31
30							
31	Total Transportation Service	477	400	877	250	248	498
32							
33	TOTAL SALES AND TRANSPORTATION SERVICES	$ 505,295	$ 400	$ 505,695	$ 499,437	$ 248	$ 499,685
34							
35	Cross Reference		- Section E-FORMULA, Sch 3			- Section E-FORMULA, Sch 4	

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2013 Rates -- Average $/GJ	Revenue -- At Existing 2013 Rates -- Revenue ($000s)	Gross Margin -- At Existing 2013 Rates -- Average $/GJ	Gross Margin -- At Existing 2013 Rates -- Margin ($000s)	Effective Increase / (Decrease) -1.72% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000s)	Average Number of Customers	Revenue Average $/GJ	Revenue Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	69,511.7	$ 9.727	$ 676,106	$ 5.333	$ 370,675	$ (0.092)	$ (6,383)	765,842	$ 9.635	$ 669,723
4	Schedule 2 - Small Commercial	24,246.8	8.419	204,130	3.969	96,241	(0.068)	(1,657)	72,614	8.351	202,473
5	Schedule 3 - Large Commercial	17,253.0	7.142	123,215	3.040	52,444	(0.052)	(904)	4,577	7.090	122,311
6	Schedules 1, 2 and 3	111,011.5		1,003,451		519,360		(8,944)	843,033		994,507
7											
8	Schedule 4 - Seasonal	169.1	5.594	946	1.875	317	(0.035)	(6)	26	5.559	940
9	Schedule 5 - General Firm	2,315.3	6.316	14,624	2.576	5,965	(0.044)	(103)	216	6.272	14,521
10											
11	Industrials										
12	Schedule 7 - Interruptible	86.7	5.294	459	1.580	137	(0.023)	(2)	3	5.271	457
13											
14	Schedule 6 - N G V Fuel - Stations	61.4	7.606	467	4.218	259	(0.065)	(4)	14	7.541	463
15	Schedule 16 - Liquefied Natural Gas (LNG)	1,341.3	8.053	10,801	4.120	5,526	(0.071)	(95)	8	7.982	10,706
16	Total Sales	114,985.3		1,030,748		531,564		(9,154)	843,300		1,021,594
17											
18	TRANSPORTATION SERVICE										
19	Schedule 22 - Firm Service	13,188.4	0.637	8,396	0.633	8,352	(0.011)	(144)	14	0.626	8,252
20	- Interruptible Service	15,822.0	0.932	14,740	0.927	14,667	(0.016)	(252)	25	0.916	14,488
21	Schedule 23 - Large Commercial	8,721.3	3.069	26,766	3.064	26,723	(0.053)	(460)	1,560	3.016	26,306
22	Schedule 25 - Firm Service	12,604.4	2.074	26,140	2.069	26,081	(0.036)	(449)	487	2.038	25,691
23	Schedule 27 - Interruptible Service	6,476.3	1.378	8,922	1.373	8,891	(0.024)	(153)	95	1.354	8,769
24											
25	Total Transportation Service	56,812.4		84,964		84,714		(1,458)	2,181		83,506
26											
27	Total Non-Bypass Sales & Transportation Service	171,797.7		$ 1,115,712		$ 616,278		$ (10,612)	845,481		$ 1,105,100
28											
29	Cross Reference	ection E-FORMULA, Sch 6	- Section E-FORMULA, Sch 8				- Section E-FORMULA, Sch 2				

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

			Revenue -- At Existing 2013 Rates --		Gross Margin -- At Existing 2013 Rates --		Increase / (Decrease) -1.72% of Margin			Revenue	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	6,553.2	$ 0.126	$ 823	$ 0.121	$ 791	$ -	$ -	5	$ 0.126	$ 823
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	176.6	0.181	32	0.181	32	-	-	1	0.181	32
6	Burrard Thermal - Firm	482.5	20.653	9,965	20.647	9,962	-	-	1	20.653	9,965
7	FEVI - Firm (Revenue/Margin in Other Revenue - Sch13)	33,720.0	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
9	Schedule 25 - Firm Service	837.3	0.841	704	0.836	700	-	-	6	0.841	704
10	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	41,769.6		11,524		11,485		-	15		11,524
12											
13	TOTAL NON-BYPASS AND BYPASS SALES AND										
14	TRANSPORTATION SERVICE	213,567.3		$ 1,127,236		$ 627,763		$ (10,612)	845,496		$ 1,116,624
15											
16	Cross Reference	ection E-FORMULA, Sch 6	- Section E-FORMULA, Sch 8				- Section E-FORMULA, Sch 2				

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 2,402	$ 2,333	$ 2,134	$ (199)	- Section E-FORMULA, Sch 56
4						
5	Connection Charge	2,390	2,685	2,622	(63)	- Section E-FORMULA, Sch 56
6						
7	NSF Returned Cheque Charges	110	79	79	-	- Section E-FORMULA, Sch 56
8						
9	Other Recoveries	237	126	284	158	- Section E-FORMULA, Sch 56
10						
11	Total Other Utility Revenue	5,139	5,223	5,119	(104)	
12						
13	**Miscellaneous Revenue**					
14						
15	FEVI Wheeling Charge	3,353	3,464	3,464	-	
16						
17	SCP Third Party Revenue	15,272	14,827	14,773	(54)	
18						
19	FEVI SAP Lease Income	17	-	-	-	- Section E-FORMULA, Sch 56
20						
21	NGT Overhead and Marketing Recovery	-	-	-	-	- Section E-FORMULA, Sch 56
22						
23	Surrey & Burnaby Operations CNG Pump Charges	-	-	(55)	(55)	- Section E-FORMULA, Sch 56
24						
25	Biomethane Other Revenue	-	(29)	(97)	(68)	- Section E-FORMULA, Sch 56
26						
27	CNG & LNG Service Revenues	720	1,304	-	(1,304)	- Section E-FORMULA, Sch 56
28						
29						
30	Total Miscellaneous	19,362	19,566	18,085	(1,481)	
31						
32	**Total Other Operating Revenue**	$ 24,501	$ 24,789	$ 23,204	$ (1,585)	- Section E-FORMULA, Sch 3

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,134	$ 2,114	$ (20)	- Section E-FORMULA, Sch 56
4					
5	Connection Charge	2,622	2,636	14	- Section E-FORMULA, Sch 56
6					
7	NSF Returned Cheque Charges	79	79	-	- Section E-FORMULA, Sch 56
8					
9	Other Recoveries	284	284	-	- Section E-FORMULA, Sch 56
10					
11	Total Other Utility Revenue	5,119	5,113	(6)	
12					
13	**Miscellaneous Revenue**				
14					
15	FEVI Wheeling Charge	3,464	3,365	(99)	- Section E-FORMULA, Sch 2
16					
17	SCP Third Party Revenue	14,773	14,773	-	- Section E-FORMULA, Sch 2
18					
19	FEVI SAP Lease Income	-	-	-	- Section E-FORMULA, Sch 56
20					
21	NGT Overhead and Marketing Recovery	-	490	490	- Section E-FORMULA, Sch 56
22					
23	Surrey & Burnaby Operations CNG Pump Charges	(55)	(55)	-	- Section E-FORMULA, Sch 56
24					
25	Biomethane Other Revenue	(97)	(70)	27	- Section E-FORMULA, Sch 56
26					
27	CNG & LNG Service Revenues	-	-	-	- Section E-FORMULA, Sch 56
28					
29					
30	Total Miscellaneous	18,085	18,503	418	
31					
32	**Total Other Operating Revenue**	$ 23,204	$ 23,616	$ 412	- Section E-FORMULA, Sch 4

FORMULA GROSS OPERATING & MAINTENANCE EXPENSE
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

Line No.	Particulars		2013 Base	2014 Formula	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1					
2					
3	**Cost Drivers for Formulaic O&M**				
4	CPI			1.83%	
5	AWE			2.70%	
6	Labour Split				
7	Non Labour			45.00%	
8	Labour			55.00%	
9	CPI/AWE	(line 4 * line 7) + (line 5 * line 8)		2.31%	
10	Productivity Factor			-0.50%	
11	Customer Growth			0.57%	
12	Net Inflation Factor	(1 + line 9 + line 10) * (1 + line 11)		**102.39%**	
13					
14	**2013 Base O&M**		$ 230,985		
15	Remove O&M tracked outside of Formula				
16	Pension/OPEB (O&M portion)		(25,313)		
17	Insurance		(4,710)		
18	RS 16 O&M				
19	**O&M Subject to Formula**	(prior year * line 12)	200,963	205,762	
20	O&M tracked outside of Formula				
21	Pension/OPEB (O&M portion)		25,313	24,113	
22	Insurance		4,710	4,990	
23	RS 16 O&M		-	376	
24					
25	**Formulaic O&M**		230,985	235,241	- Section E-FORMULA, Sch 15
26	Cross Reference		- Table C3-2 in Application		- Section E-FORMULA, Sch 18
27					

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	M&E Costs	$ 50,708	$ 59,097	$ 55,817		
2	COPE Costs	32,450	37,183	31,780		
3	COPE Customer Services Costs	11,825	11,144	11,644		
4	IBEW Costs	27,180	27,640	26,472		
5						
6	**Labour Costs**	**122,164**	**135,064**	**125,713**		
7						
8	Vehicle Costs	3,807	3,685	3,855		
9	Employee Expenses	5,898	5,716	5,671		
10	Materials and Supplies	7,903	7,019	6,841		
11	Computer Costs	14,570	14,769	15,274		
12	Fees and Administration Costs	38,611	37,905	38,449		
13	Contractor Costs	31,955	38,335	40,896		
14	Facilities	15,486	14,284	13,976		
15	Recoveries & Revenue	(20,689)	(20,774)	(19,055)		
16						
17	**Non-Labour Costs**	**97,540**	**100,939**	**105,906**		
18						
19						
20	**Total Gross O&M Expenses**	**219,704**	**236,003**	**231,618**	**235,241**	
21						
22	Less: Capitalized Overhead	(31,779)	(33,040)	(33,040)	(32,934)	
23						
24	**Total O&M Expenses**	**$ 187,925**	**$ 202,963**	**$ 198,578**	**$ 202,307**	
25						
26	Cross Reference			- Section E-FORMULA, Sch 3		
27					- Section E-FORMULA, Sch 4	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Supervision	110-11	$ 10,578	$ 11,026	$ 11,194		
2	Distribution Supervision Total	110-10	10,578	11,026	11,194		
3							
4	Operation Centre - Distribution	110-21	10,112	11,074	9,901		
5	Preventative Maintenance - Distribution	110-22	2,644	2,990	2,844		
6	Operations - Distribution	110-23	5,538	5,904	6,409		
7	Emergency Management - Distribution	110-24	5,405	5,077	5,337		
8	Field Training - Distribution	110-25	1,746	4,088	3,153		
9	Meter Exchange - Distribution	110-26	2,397	2,231	2,373		
10	Distribution Operations Total	110-20	27,842	31,363	30,018		
11							
12	Corrective - Distribution	110-31	5,564	4,643	5,559		
13	Distribution Maintenance Total	110-30	5,564	4,643	5,559		
14							
15	Account Services - Distribution	110-41	1,111	1,004	1,081		
16	Bad Debt Management - Distribution	110-42	585	599	443		
17	Distribution Meter to Cash Total	110-40	1,697	1,603	1,524		
18							
19	**Distribution Total**	**110**	**45,680**	**48,635**	**48,295**		
20							
21	Transmission Supervision	120-11	535	482	606		
22	Transmission Supervision Total	120-10	535	482	606		
23							
24	Pipeline / Right of Way Operations	120-21	7,287	6,096	6,163		
25	Compression Operations	120-22	1,827	2,112	1,813		
26	Measurement Control Operations	120-23	103	-	-		
27	Transmission Operations Total	120-20	9,217	8,208	7,976		
28							
29	Pipeline / Right of Way - Maintenance	120-31	1,830	2,707	3,206		
30	Compression - Maintenance	120-32	554	1,147	1,216		
31	Measurement Control Operations	120-33	117	119	201		
32	Transmission Maintenance Total	120-30	2,501	3,973	4,623		
33							
34	**Transmission Total**	**120**	**12,253**	**12,663**	**13,205**		
35							
36	LNG Operations	130-11	1,601	1,617	1,717		
37	LNG Operations Total	130-10	1,601	1,617	1,717		
38							
39	LNG Plant Maintenance	130-21	272	274	292		
40	LNG Plant Maintenance Total	130-20	272	274	292		
41							
42	**LNG Plant Total**	**130**	**1,873**	**1,891**	**2,009**		
43							
44	**Operations Total**	**100**	**59,806**	**63,189**	**63,509**		
45							
46	Customer Service Supervision	210-11	482	566	566		
47	Customer Assistance	210-12	11,513	11,493	11,480		
48	Customer Billing	210-13	18,586	14,494	14,494		
49	Meter Reading	210-14	12,178	19,696	19,696		
50	Credit & Collections	210-15	3,028	3,851	3,787		
51	Customer Operations	210-16	2,385	2,353	2,088		
52	Customer Service Total	210-10	48,172	52,452	52,110		
53							
54	**Customer Service Total**	**210**	**48,172**	**52,452**	**52,110**		
55							
56	**Customer Service Total**	**200**	**48,172**	**52,452**	**52,110**		

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Energy Solutions & External Relations Supervisi	310-11	614	796	$ 671		
2	Energy Solutions	310-12	5,134	4,991	5,117		
3	Energy Efficiency	310-13	117	120	301		
4	Corporate Communications and External Relatio	310-14	7,212	6,155	6,988		
5	Forecasting, Market & Business Development	310-15	4,998	6,119	6,138		
6	Energy Solutions & External Relations Total	310-10	18,075	18,181	19,215		
7							
8	**Energy Solutions & External Relations Total**	**310**	**18,075**	**18,181**	**19,215**		
9							
10	**Energy Solutions & External Relations Total**	**300**	**18,075**	**18,181**	**19,215**		
11							
12	Energy Supply & Resource Development	410-11	1,937	2,136	2,550		
13	Gas Control	410-12	1,551	1,602	1,451		
14	Energy Supply & Resource Development Tot	410-10	3,488	3,738	4,000		
15							
16	**Energy Supply & Resource Development Tot**	**410**	**3,488**	**3,738**	**4,000**		
17							
18	Information Technology Supervision	420-11	4,172	4,577	4,001		
19	Application Management	420-12	11,251	12,083	11,980		
20	Infrastructure Management	420-13	8,018	8,719	8,236		
21	Information Technology Total	420-10	23,442	25,379	24,217		
22							
23	**Information Technology Total**	**420**	**23,442**	**25,379**	**24,217**		
24							
25	System Planning	430-11	5,672	8,394	7,675		
26	Engineering	430-12	6,803	7,027	6,760		
27	Project Management	430-13	1,125	1,535	1,021		
28	Engineering Services & Project Management	430-10	13,599	16,956	15,456		
29							
30	**Engineering Services & Project Management**	**430**	**13,599**	**16,956**	**15,456**		
31							
32	Supply Chain	440-11	4,420	4,884	4,450		
33	Measurement	440-12	5,548	6,688	6,124		
34	Property Services	440-13	1,070	1,418	1,293		
35	Operations Support Total	440-10	11,038	12,990	11,867		
36							
37	**Operations Support Total**	**440**	**11,038**	**12,990**	**11,867**		
38							
39	Facilities Management	450-11	9,563	9,259	9,249		
40	Facilities Total	450-10	9,563	9,259	9,249		
41							
42	**Facilities Total**	**450**	**9,563**	**9,259**	**9,249**		
43							
44	Environment Health & Safety	460-11	2,481	2,999	2,681		
45	Environment Health & Safety Total	460-10	2,481	2,999	2,681		
46							
47	**Environment Health & Safety Total**	**460**	**2,481**	**2,999**	**2,681**		
48							
49							
50	**Business Services Total**	**400**	**63,611**	**71,321**	**67,470**		

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Financial & Regulatory Services	510-11	12,149	14,184	13,279		
2	Financial & Regulatory Services Total	510-10	12,149	14,184	13,279		
3							
4	**Financial & Regulatory Services Total**	**510**	**12,149**	**14,184**	**13,279**		
5							
6	Human Resources	520-11	8,610	8,511	8,458		
7	Human Resources Total	520-10	8,610	8,511	8,458		
8							
9	**Human Resources Total**	**520**	**8,610**	**8,511**	**8,458**		
10							
11	Legal	530-11	1,917	2,282	2,282		
12	Internal Audit	530-12	695	755	755		
13	Risk Management/Insurance	530-13	4,754	4,898	4,898		
14	Governance	530-10	7,366	7,935	7,935		
15							
16	**Governance Total**	**530**	**7,366**	**7,935**	**7,935**		
17							
18	Administration & General	540-11	226	(46)	269		
19	Shared Services Agreement	540-12	(5,984)	(5,581)	(6,483)		
20	Retiree Benefits	540-16	7,673	5,857	5,857		
21	Corporate Total	540-10	1,915	230	(357)		
22							
23	**Corporate Total**	**540**	**1,915**	**230**	**(357)**		
24							
25	**Corporate Services Total**	**500**	**30,041**	**30,860**	**29,314**		
26							
27	**Total Gross O&M Expenses**		**219,704**	**236,003**	**231,618**	**235,241**	
28							
29	Less: Capitalized Overhead		(31,779)	(33,040)	(33,040)	(32,934)	
30							
31	**Total O&M Expenses**		**$ 187,925**	**$ 202,963**	**$ 198,578**	**$ 202,307**	
32							
33	Cross Reference				- Section E-FORMULA, Sch 3		
34						- Section E-FORMULA, Sch 4	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Total Expenses	2013 PROJECTED 2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 13,283	$ 13,728	$ 12,542	$ 12,542	$ (1,186)	
4							
5	General, School and Other	34,132	37,511	35,547	35,547	(1,964)	
6							
7		47,415	51,239	48,089	48,089	(3,150)	
8							
9	Add / Less: Deferred Property Taxes	2,241	-	3,150	3,150	3,150	
10							
11	Total	$ 49,656	$ 51,239	$ 51,239	$ 51,239	$ -	- Section E-FORMULA, Sch 3

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Total Expenses	2014 2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 12,542	$ 12,032	$ 12,032	$ (510)	
4						
5	General, School and Other	35,547	36,765	36,765	1,218	
6						
7		48,089	48,797	48,797	708	
8						
9	Add / Less: Deferred Property Taxes	3,150	-	-	(3,150)	
10						
11	Total	$ 51,239	$ 48,797	$ 48,797	$ (2,442)	- Section E-FORMULA, Sch 4

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 118,639	$ 123,842	$ 123,842	$ -	- Section E-FORMULA, Sch 41
4						
5	Less: Amortization of Contributions in Aid of Construction	(6,558)	(6,499)	(6,499)	-	- Section E-FORMULA, Sch 45
6		112,081	117,343	117,343	-	- Section E-FORMULA, Sch 25
7						
8	**Amortization Expense**					
9						
10	Amortization of Deferred Charges	$ 11,847	$ 25,569	$ 25,569	$ -	- Section E-FORMULA, Sch 48
11						
12	TOTAL	123,928	142,912	142,912	$ -	- Section E-FORMULA, Sch 3

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 123,842	$ 124,759	$ 917	- Section E-FORMULA, Sch 44
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,499)	(6,320)	179	- Section E-FORMULA, Sch 46
6		117,343	118,439	1,096	- Section E-FORMULA, Sch 26
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 25,569	$ 30,216	$ 4,647	- Section E-FORMULA, Sch 50
11					
12	TOTAL	$ 142,912	148,655	$ 5,743	- Section E-FORMULA, Sch 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing Rates	2013 PROJECTED Revised Revenue	2013 PROJECTED Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 221,574	$ 216,404	$ 218,996	$ -	$ 218,996	$ 2,592	- Section E-FORMULA, Sch 3
3	Deduct - Interest on Debt	(108,979)	(111,220)	(109,825)	-	(109,825)	1,395	- Section E-FORMULA, Sch 59
4	Net Additions (Deductions)	(31,957)	(21,038)	(26,648)	-	(26,648)	(5,610)	- Section E-FORMULA, Sch 25
5	Accounting Income After Tax	$ 80,638	$ 84,146	$ 82,523	$ -	$ 82,523	$ (1,623)	
6								
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	75.00%	0.00%	
9								
10	Taxable Income	$ 107,518	$ 112,195	$ 110,031	$ -	$ 110,031	$ (2,164)	
11								
12								
13	Income Tax - Current	$ 26,880	$ 28,049	$ 27,508	$ -	$ 27,508	$ (541)	
14	Previous Year Adjustment	-	-		-		-	
15								
16	**Total Income Tax**	$ 26,880	$ 28,049	$ 27,508	$ -	$ 27,508	$ (541)	- Section E-FORMULA, Sch 3

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

			2014				
Line No.	Particulars	2013 PROJECTED	Existing Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 218,996	$ 211,927	$ (7,959)	$ 203,968	$ (15,028)	- Section E-FORMULA, Sch 4
3	Deduct - Interest on Debt	(109,825)	(109,691)	1	(109,690)	135	- Section E-FORMULA, Sch 60
4	Net Additions (Deductions)	(26,648)	16,206	-	16,206	42,854	- Section E-FORMULA, Sch 26
5	Accounting Income After Tax	82,523	$ 118,442	$ (7,958)	$ 110,484	$ 27,961	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	110,031	$ 157,923	$ (10,611)	$ 147,312	$ 37,281	
11							
12							
13	Income Tax - Current	$ 27,508	$ 39,481	$ (2,653)	$ 36,828	$ 9,320	
14	Previous Year Adjustment	-		-		-	
15							
16	**Total Income Tax**	$ 27,508	$ 39,481	$ (2,653)	$ 36,828	$ 9,320	- Section E-FORMULA, Sch 4

FORTISBC ENERGY INC. | June 10, 2013 | Section E FORMULA Schedule 25

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 677	$ 700	700	$ -	
3	Depreciation	112,081	117,343	117,343	-	- Section E-FORMULA, Sch 21
4	Amortization of Debt Issue Expenses	537	622	561	(61)	
5	Vehicles: Interest & Capitalized Depreciation	1,898	2,187	1,692	(495)	
6	Pension Expense	14,097	12,530	12,530	-	
7	OPEB Expense	4,765	4,902	4,902	-	
8	Olympic Cauldron (50% NBV)	1,445	-	-	-	
9	Bad Debt Provision	726	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	11,847	25,569	25,569	-	- Section E-FORMULA, Sch 21
13	Capital Cost Allowance	(129,279)	(136,232)	(136,232)	-	- Section E-FORMULA, Sch 27
14	Cumulative Eligible Capital Allowance	(907)	(857)	(865)	(8)	
15	Debt Issue Costs	(834)	(411)	(385)	26	
16	Vehicle Lease Payment	(3,432)	(4,613)	(4,183)	430	
17	Pension Contributions	(13,920)	(12,006)	(12,666)	(660)	
18	OPEB Contributions	(1,667)	(2,367)	(2,407)	(40)	
19	Overheads Capitalized Expensed for Tax Purposes	(13,620)	(14,160)	(14,160)	-	
20	Removal Costs	(14,766)	(12,932)	(14,201)	(1,269)	
21	Discounts on Debt Issue and Other	-	-	-	-	
22	Major Inspection Costs	(1,606)	(1,342)	(4,943)	(3,601)	
23	SCP Landscaping Deduction	-	-	-	-	
24	Biomethane Other Revenue	-	29	97	68	
25	TOTAL	(31,957)	(21,038)	$ (26,648)	$ (5,610)	- Section E-FORMULA, Sch 23

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 700	800	$ 100	
3	Depreciation	117,343	118,439	1,096	- Section E-FORMULA, Sch 22
4	Amortization of Debt Issue Expenses	561	734	173	
5	Vehicles: Interest & Capitalized Depreciation	1,692	1,372	(320)	
6	Pension Expense	12,530	20,004	7,474	
7	OPEB Expense	4,902	8,662	3,760	
8	Olympic Cauldron (50% NBV)	-	-	-	
9	Bad Debt Provision	-	-	-	
10					
11	**Deductions:**				
12	Amortization of Deferred Charges	25,569	30,216	4,647	- Section E-FORMULA, Sch 22
13	Capital Cost Allowance	(136,232)	(113,003)	23,229	- Section E-FORMULA, Sch 28
14	Cumulative Eligible Capital Allowance	(865)	(804)	61	
15	Debt Issue Costs	(385)	(202)	183	
16	Vehicle Lease Payment	(4,183)	(3,006)	1,177	
17	Pension Contributions	(12,666)	(16,114)	(3,448)	
18	OPEB Contributions	(2,407)	(2,631)	(224)	
19	Overheads Capitalized Expensed for Tax Purposes	(14,160)	(14,114)	46	
20	Removal Costs	(14,201)	(12,486)	1,715	
21	Discounts on Debt Issue and Other	-	-	-	
22	Major Inspection Costs	(4,943)	(1,731)	3,212	
23	SCP Landscaping Deduction	-	-	-	
24	Biomethane Other Revenue	97	70	(27)	
25	TOTAL	$ (26,648)	$ 16,206	$ 42,854	- Section E-FORMULA, Sch 24

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,044,769	$ -	$ -	$ (41,791)	$ 1,002,978
2	1(b)	6%	27,756	-	5,949	(1,844)	31,861
3	2	6%	136,353	-	-	(8,181)	128,172
4	3	5%	2,423	-	-	(121)	2,302
5	6	10%	150	-	-	(15)	135
6	7	15%	5,442	-	2,067	(971)	6,538
7	8	20%	23,402	(1,412)	5,966	(4,995)	22,961
8	10	30%	1,680	-	-	(504)	1,176
9	12	100%	26,830	-	12,960	(33,310)	6,480
10	13	manual	3,517	-	163	(687)	2,993
11	14	manual	-	-	-	-	-
12	17	8%	174	-	-	(14)	160
13	38	30%	511	-	-	(153)	358
14	39	25%	-	-	-	-	-
15	45	45%	202	-	-	(91)	111
16	47	8%	5,496	-	1,835	(513)	6,818
17	49	8%	77,300	-	17,021	(6,865)	87,456
18	50	55%	7,461	-	8,640	(6,479)	9,622
19	51	6%	336,347	-	94,601	(23,019)	407,929
20	43.2	50%	-	-	-	-	-
21		Total	$ 1,699,813	$ (1,412)	$ 149,202	$ (129,553)	$ 1,718,050
22							
23	Add: Depreciation variance adjustment					(6,679)	
24	Approved CCA					(136,232)	
25							
26	Cross Reference					- Section E-FORMULA, Sch 25	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Class	CCA Rate	12/31/2013 UCC Balance	Adjustments	2014 Net Additions	2014 CCA	12/31/2014 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,002,978	$ -	$ 273	$ (40,125)	$ 963,126
2	1(b)	6%	31,861	-	6,477	(2,106)	36,232
3	2	6%	128,172	-	-	(7,690)	120,482
4	3	5%	2,302	-	-	(115)	2,187
5	6	10%	135	-	-	(14)	121
6	7	15%	6,538	-	2,274	(1,151)	7,661
7	8	20%	22,961	-	6,505	(5,243)	24,223
8	10	30%	1,176	-	2,441	(719)	2,898
9	12	100%	6,480	-	11,873	(12,417)	5,936
10	13	manual	2,993	-	178	(303)	2,868
11	14	manual	-	-	-	-	-
12	17	8%	160	-	-	(13)	147
13	38	30%	358	-	-	(107)	251
14	39	25%	-	-	-	-	-
15	45	45%	111	-	-	(50)	61
16	47	8%	6,818	-	2,018	(626)	8,210
17	49	8%	87,456	-	5,989	(7,236)	86,209
18	50	55%	9,622	-	8,576	(7,650)	10,548
19	51	6%	407,929	-	98,735	(27,438)	479,226
20	43.2	50%	-	-	-	-	-
21		Total	$ 1,718,050	$ -	$ 145,339	$ (113,003)	$ 1,750,386
22							
23							
24							
25							
26	Cross Reference					- Section E-FORMULA, Sch 26	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	Adjustments	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	Gas Plant in Service, Beginning	$ 3,545,030	$ 3,774,425	$ 3,726,853	$ -	$ 3,726,853	$ (47,572)	- Section E-FORMULA, Sch 35
2	Opening Balance Adjustment	(3,890)	-	(3,818)	-	(3,818)	(3,818)	
3	Gas Plant in Service, Ending	3,726,853	3,905,299	3,870,159	-	3,870,159	(35,140)	- Section E-FORMULA, Sch 35
4								
5	Accumulated Depreciation Beginning - Plant	$ (922,011)	$ (1,012,343)	$ (1,011,179)	$ -	$ (1,011,179)	$ 1,164	- Section E-FORMULA, Sch 41
6	Opening Balance Adjustment	4,463	-	518	-	518	518	
7	Accumulated Depreciation Ending - Plant	(1,011,179)	(1,104,066)	(1,105,308)	-	(1,105,308)	(1,242)	- Section E-FORMULA, Sch 41
8								
9	CIAC, Beginning	$ (180,038)	$ (191,772)	$ (185,545)	$ -	$ (185,545)	$ 6,227	- Section E-FORMULA, Sch 45
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	CIAC, Ending	(185,545)	(198,468)	(194,421)	-	(194,421)	4,047	- Section E-FORMULA, Sch 45
12								
13	Accumulated Amortization Beginning - CIAC	$ 49,620	$ 51,072	$ 51,143	$ -	$ 51,143	$ 71	- Section E-FORMULA, Sch 45
14	Opening Balance Adjustment	(5)	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	51,143	57,367	57,362	-	57,362	(5)	- Section E-FORMULA, Sch 45
16								
17	Net Plant in Service, Mid-Year	$ 2,537,220	$ 2,640,757	$ 2,602,882	$ -	$ 2,602,882	$ (37,875)	
18								
19	Adjustment to 13-Month Average	30,786	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	20,803	26,120	-	26,120	5,317	
21	Unamortized Deferred Charges	497	8,249	(7,840)	-	(7,840)	(16,089)	- Section E-FORMULA, Sch 48
22	Cash Working Capital	(1,899)	(2,293)	(1,591)	-	(1,591)	702	- Section E-FORMULA, Sch 53
23	Other Working Capital	101,416	101,622	83,121	-	83,121	(18,501)	- Section E-FORMULA, Sch 53
24	Deferred Income Taxes Regulatory Asset	281,929	282,359	284,958	-	284,958	2,599	- Section E-FORMULA, Sch 58
25	Deferred Income Taxes Regulatory Liability	(281,929)	(282,359)	(284,958)	-	(284,958)	(2,599)	- Section E-FORMULA, Sch 58
26	LILO Benefit	(1,316)	(1,150)	(1,150)	-	(1,150)	-	
27	**Utility Rate Base**	$ 2,692,824	$ 2,767,988	$ 2,701,542	$ -	$ 2,701,542	$ (66,446)	- Section E-FORMULA, Sch 59
28								- Section E-FORMULA, Sch 3

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	Adjustments	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,726,853	$ 3,870,159	$ -	$ 3,870,159	$ 143,306	- Section E-FORMULA, Sch 38
2	Opening Balance Adjustment	(3,818)	-	-	-	3,818	
3	Gas Plant in Service, Ending	3,870,159	4,008,286	-	4,008,286	138,127	- Section E-FORMULA, Sch 38
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,011,179)	$ (1,105,308)	$ -	$ (1,105,308)	$ (94,129)	- Section E-FORMULA, Sch 44
6	Opening Balance Adjustment	518	-	-	-	(518)	
7	Accumulated Depreciation Ending - Plant	(1,105,308)	(1,206,067)	-	(1,206,067)	(100,759)	- Section E-FORMULA, Sch 44
8							
9	CIAC, Beginning	$ (185,545)	$ (194,421)	$ -	$ (194,421)	$ (8,876)	- Section E-FORMULA, Sch 46
10	Opening Balance Adjustment	-	-	-	-	-	
11	CIAC, Ending	(194,421)	(196,276)	-	(196,276)	(1,855)	- Section E-FORMULA, Sch 46
12							
13	Accumulated Amortization Beginning - CIAC	$ 51,143	$ 57,362	$ -	$ 57,362	$ 6,219	- Section E-FORMULA, Sch 46
14	Opening Balance Adjustment	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	57,362	59,914	-	59,914	2,552	- Section E-FORMULA, Sch 46
16							
17	Net Plant in Service, Mid-Year	$ 2,602,882	$ 2,646,825	$ -	$ 2,646,825	$ 43,943	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	(7,840)	47,872	-	47,872	55,712	- Section E-FORMULA, Sch 50
22	Cash Working Capital	(1,591)	(248)	(28)	(276)	1,315	- Section E-FORMULA, Sch 54
23	Other Working Capital	83,121	79,039	-	79,039	(4,082)	- Section E-FORMULA, Sch 54
24	Deferred Income Taxes Regulatory Asset	284,958	288,453	-	288,453	3,495	- Section E-FORMULA, Sch 58
25	Deferred Income Taxes Regulatory Liability	(284,958)	(288,453)	-	(288,453)	(3,495)	- Section E-FORMULA, Sch 58
26	LILO Benefit	(1,150)	(983)	-	(983)	167	
27	**Utility Rate Base**	$ 2,701,542	$ 2,798,625	$ (28)	$ 2,798,597	$ 97,055	- Section E-FORMULA, Sch 60
28							- Section E-FORMULA, Sch 4

FORMULA CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

Line No.	Particulars		2013 Base	2014 Formula	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1					
2					
3	**Cost Drivers for Formulaic Capital**				
4	CPI			1.83%	
5	AWE			2.70%	
6	Labour Split				
7	Non Labour			45.00%	
8	Labour			55.00%	
9	CPI/AWE	(line 4 * line 7) + (line 5 * line 8)		2.31%	
10	Productivity Factor			-0.50%	
11	Net Inflation Factor			**1.81%**	
12					
13	Forecast Service Line Additions		7,989	8,051	
14	Average Growth Capital per Service Line Addition	(prior year * line 11)	$ 2,738.92	$ 2,788.50	
15					
16	Forecast Customer Growth			0.57%	
17					
18	**2013 Base Capital Expenditures**				
19	Growth Capital	(Line 13 * Line 14)	21,881	22,450	
20	Sustainment Capital	(prior year * (1 + Line 11) * (1 + Line 16)	70,902	72,595	
21	Other Capital	(prior year * (1 + Line 11) * (1 + Line 16)	31,173	31,918	
22	**Capital Subject to Formula**		123,956	126,963	
23	**Add: Capital Tracked Outside of the Formula**				
24	Insurance & OPEB		2,241	2,068	
25	**Formulaic Capital**		126,197	129,030	- Section E-FORMULA, Sch 38 -
26	Cross Reference		- Table C4-2 in Application		- Section E-FORMULA, Sch 46
27					

FORTISBC ENERGY INC. June 10, 2013 Section E FORMULA Schedule 32

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	2013 Projected	2014 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPITAL EXPENDITURES**			
2				
3	Regular Capital Expenditures			
4				
5	Regular Capital Expenditures	$ 129,644	$ 134,654	
6	Gateway Project	3,012	-	
7				
8	Total Regular Capital Expenditures	$ 132,656	$ 134,654	
9				
10	TOTAL CAPITAL EXPENDITURES	$ 132,656	$ 134,654	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
14				
15	Regular Capital			
16	Regular Capital Expenditures	$ 132,656	$ 134,654	
17	Add - Opening WIP	43,661	31,463	
18	Less - Adjustments	-	-	
19	Less - Closing WIP	(31,463)	(31,463)	
20	Capital Spares Inventory	-	-	
21	Capital Vehicle Lease	2,400	-	
22	Add - AFUDC	1,954	1,640	
23	Add - Overhead Capitalized	33,040	32,934	
24				
25	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 182,249	$ 169,228	
26				
27	Special Projects - CPCN's			
28	CPCN Expenditures	$ -	$ -	
29	Add - Opening WIP	(158)	-	
30	Less - Closing WIP	-	-	
31	Add: Projects transferred from Deferral Accounts	158	-	
32	Less: Projects settling to Deferral Accounts	-	-	
33	Less: Adjustments	-	-	
34	Less: Removal Costs	-	-	
34	Add - AFUDC	-	-	
35				
36	TOTAL CPCN ADDITIONS	$ -	$ -	
37				
38	TOTAL PLANT ADDITIONS	$ 182,249	$ 169,228	
39				
40	Cross Reference	- Section E-FORMULA, Sch 35		
41			- Section E-FORMULA, Sch 38	

FORTISBC ENERGY INC.

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

June 10, 2013

Section E
FORMULA
Schedule 33

Line No.	Particulars	Balance 31/12/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,529	-	393	-	-	-	-	44,922	44,726
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	-	-	-	-	-	-	1,209	1,209
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1	1
16	402-01 Application Software - 12.5%	85,471	-	6,480	168	-	(6,015)	-	86,104	85,788
17	402-02 Application Software - 20%	18,723	-	6,480	97	-	(2,997)	-	22,303	20,513
18	TOTAL INTANGIBLE	152,412	-	13,353	265	-	(9,012)	-	157,018	154,715
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	-	-	-	-	-	-	965	965
24	433-00 Manufact'd Gas - Equipment	448	-	210	-	71	-	-	729	589
25	434-00 Manufact'd Gas - Gas Holders	2,852	-	-	-	-	-	-	2,852	2,852
26	436-00 Manufact'd Gas - Compressor Equipment	355	-	-	-	-	-	-	355	355
27	437-00 Manufact'd Gas - Measuring & Regulating Equipme	735	-	-	-	-	-	-	735	735
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499	16,499
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,014	-	1,550	48	524	-	-	27,136	26,075
36	TOTAL MANUFACTURED	67,023	-	1,760	48	595	-	-	69,426	68,225

FORTISBC ENERGY INC. June 10, 2013 Section E

FORMULA

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued) Schedule 34

FOR THE YEAR ENDING DECEMBER 31, 2013

($000s)

Line No.	Particulars	Balance 31/12/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,299	-	-	-	-	-	-	16,299	16,299
6	463-00 Measuring Structures	5,511	-	-	-	-	(21)	-	5,490	5,501
7	464-00 Other Structures & Improvements	6,023	-	50	-	17	(29)	-	6,061	6,042
8	465-00 Mains	799,512	-	20,606	861	6,965	(374)	-	827,570	813,541
9	465-00 Mains - INSPECTION	5,803	-	4,943	-	1,671	(1,268)	-	11,149	8,476
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974	974
13	466-00 Compressor Equipment	111,811	-	1,746	83	590	(340)	-	113,890	112,851
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,249	-	-	-	-	(131)	-	30,118	30,184
17	467-10 Telemetering	9,293	-	220	10	74	(22)	-	9,575	9,434
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	995,547	-	27,565	954	9,317	(2,185)	-	1,031,198	1,013,373
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	18,219	-	-	-	-	(21)	-	18,198	18,209
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	758,346	-	23,241	-	7,856	(3,185)	-	786,258	772,302
29	474-00 House Regulators & Meter Installations	174,943	-	-	-	-	(284)	-	174,659	174,801
30	477-00 Meters/Regulators Installations	18,871	-	15,570	-	5,263	-	-	39,704	29,288
31	475-00 Mains	947,273	-	22,462	173	7,593	(1,049)	-	976,452	961,863
32	476-00 Compressor Equipment	1,450	-	-	-	-	-	(623)	827	827
33	477-00 Measuring & Regulating Equipment	88,594	-	5,845	278	1,976	(598)	-	96,095	92,345
34	477-00 Telemetering	7,102	-	644	5	218	(6)	-	7,963	7,533
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
36	478-10 Meters	207,016	-	13,250	-	-	(6,353)	-	213,913	210,465
37	478-20 Instruments	11,889	-	-	-	-	-	-	11,889	11,889
38	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,237,368	-	81,012	456	22,906	(11,496)	(623)	2,329,623	2,283,184
40										
41	**BIO GAS**									
42	472-00 Bio Gas Struct. & Improvements	137	-	-	-	-	-	-	137	137
43	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80	80
44	475-20 Bio Gas Mains – Private Land	41	-	220	-	74	-	-	335	188
45	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	-	-	-	-	-	-	-	-	-
47	477-10 Bio Gas Reg & Meter Equipment	280	-	440	-	149	-	-	869	575
48	478-30 Bio Gas Meters	7	-	440	-	-	-	-	447	227
49	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22	22
50	TOTAL BIO-GAS	567	-	1,100	-	223	-	-	1,890	1,229

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 31/12/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,554	$ -	$ -	$ -	$ -	$ -	$ (2,554)	$ -	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	47	-	-	-	-	-	(47)	-	-
4	476-30 NG Transportation CNG Foundations	471	-	-	-	-	-	(471)	-	-
5	476-40 NG Transportation LNG Foundations	4	-	-	-	-	-	(4)	-	-
6	476-50 NG Transportation LNG Pumps	-	-	-	-	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	119	-	-	-	-	-	(119)	-	-
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	3,195	-	-	-	-	-	(3,195)	-	-
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,329	-	321	-	-	-	-	22,650	22,490
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	10,770	-	-	-	-	-	-	10,770	10,770
16	- Masonry Buildings	92,527	-	4,974	-	-	-	-	97,501	95,014
17	- Leasehold Improvement	3,822	-	163	-	-	(151)	-	3,834	3,828
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,479	-	478	-	-	(303)	-	3,654	3,567
20	483-40 GP Furniture	21,395	-	1,613	-	-	(1,954)	-	21,054	21,225
21	483-10 GP Computer Hardware	29,627	-	8,640	231	-	(6,489)	-	32,009	30,818
22	483-20 GP Computer Software	3,405	-	-	-	-	(192)	-	3,213	3,309
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,208	-	-	-	-	-	-	2,208	2,208
26	484-00 Vehicles - Leased	28,385	-	2,400	-	-	(1,440)	-	29,345	28,865
27	485-10 Heavy Work Equipment	664	-	-	-	-	-	-	664	664
28	485-20 Heavy Mobile Equipment	838	-	-	-	-	-	-	838	838
29	486-00 Small Tools & Equipment	38,733	-	2,855	-	-	(963)	-	40,625	39,679
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,679	-	-	-	-	(906)	-	6,773	7,226
34	- Radio	4,856	-	1,020	-	-	(34)	-	5,842	5,349
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	270,741	-	22,464	231	-	(12,432)	-	281,004	275,873
37										
38	**UNCLASSIFIED PLANT**									
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,726,853	$ -	$ 147,254	$ 1,954	$ 33,041	$ (35,125)	$ (3,818)	$ 3,870,159	$ 3,796,597
43										
44	Cross Reference	- Section E-FORMULA, Sch 29		- Section E-FORMULA, Sch 32					- Section E-FORMULA, Sch 29	
45			- Section E-FORMULA, Sch 32			- Section E-FORMULA, Sch 32				

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,922	-	429	-	-	-	-	45,351	45,137
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	-	-	-	-	-	-	1,209	1,209
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1	1
16	402-01 Application Software - 12.5%	86,104	-	6,307	184	-	(3,738)	-	88,857	87,481
17	402-02 Application Software - 20%	22,303	-	5,566	111	-	(2,317)	-	25,663	23,983
18	TOTAL INTANGIBLE	157,018	-	12,302	295	-	(6,055)	-	163,560	160,289
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	-	-	-	-	-	-	965	965
24	433-00 Manufact'd Gas - Equipment	729	-	229	-	88	-	-	1,046	888
25	434-00 Manufact'd Gas - Gas Holders	2,852	-	-	-	-	-	-	2,852	2,852
26	436-00 Manufact'd Gas - Compressor Equipment	355	-	-	-	-	-	-	355	355
27	437-00 Manufact'd Gas - Measuring & Regulating Equipme	735	-	-	-	-	-	-	735	735
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499	16,499
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	27,136	-	1,690	65	647	-	-	29,538	28,337
36	TOTAL MANUFACTURED	69,426	-	1,919	65	735	-	-	72,145	70,786

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,299	-	-	-	-	-	-	16,299	16,299
6	463-00 Measuring Structures	5,490	-	-	-	-	(21)	-	5,469	5,480
7	464-00 Other Structures & Improvements	6,061	-	-	-	-	-	-	6,061	6,061
8	465-00 Mains	827,570	-	10,002	411	3,830	(374)	-	841,439	834,505
9	465-00 Mains - INSPECTION	11,149	-	1,731	-	663	(368)	-	13,175	12,162
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974	974
13	466-00 Compressor Equipment	113,890	-	1,904	87	729	(371)	-	116,239	115,065
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,118	-	-	-	-	(131)	-	29,987	30,053
17	467-10 Telemetering	9,575	-	240	10	92	(24)	-	9,893	9,734
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	1,031,198	-	13,877	508	5,314	(1,289)	-	1,049,608	1,040,403
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	18,198	-	-	-	-	(21)	-	18,177	18,188
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	786,258	-	25,309	-	9,686	(3,185)	-	818,068	802,163
29	474-00 House Regulators & Meter Installations	174,659	-	-	-	-	(6)	-	174,653	174,656
30	477-00 Meters/Regulators Installations	39,704	-	18,442	129	7,058	-	-	65,333	52,519
31	475-00 Mains	976,452	-	18,818	102	7,196	(1,049)	-	1,001,519	988,986
32	476-00 Compressor Equipment	827	-	-	-	-	-	-	827	827
33	477-00 Measuring & Regulating Equipment	96,095	-	6,271	303	2,400	(598)	-	104,471	100,283
34	477-00 Telemetering	7,963	-	702	6	269	(6)	-	8,934	8,449
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
36	478-10 Meters	213,913	-	12,340	-	-	(6,672)	-	219,581	216,747
37	478-20 Instruments	11,889	-	-	-	-	-	-	11,889	11,889
38	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,329,623	-	81,882	540	26,609	(11,537)	-	2,427,117	2,378,370
40										
41	**BIO GAS**									
42	472-00 Bio Gas Struct. & Improvements	137	-	-	-	-	-	-	137	137
43	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80	80
44	475-20 Bio Gas Mains – Private Land	335	-	240	-	92	-	-	667	501
45	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	-	-	-	-	-	-	-	-	-
47	477-10 Bio Gas Reg & Meter Equipment	869	-	480	-	184	-	-	1,533	1,201
48	478-30 Bio Gas Meters	447	-	480	-	-	-	-	927	687
49	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22	22
50	TOTAL BIO-GAS	1,890	-	1,200	-	276	-	-	3,366	2,628

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	-	-	-	-	-	-	-	-	-
4	476-30 NG Transportation CNG Foundations	-	-	-	-	-	-	-	-	-
5	476-40 NG Transportation LNG Foundations	-	-	-	-	-	-	-	-	-
6	476-50 NG Transportation LNG Pumps	-	-	-	-	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	-	-	-	-	-	-	-	-	-
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-	-	-	-	-	-	-	-	-
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,650	-	350	-	-	-	-	23,000	22,825
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	10,770	-	-	-	-	-	-	10,770	10,770
16	- Masonry Buildings	97,501	-	5,424	-	-	-	-	102,925	100,213
17	- Leasehold Improvement	3,834	-	178	-	-	(40)	-	3,972	3,903
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,654	-	521	-	-	(92)	-	4,083	3,869
20	483-40 GP Furniture	21,054	-	1,759	-	-	(3,123)	-	19,690	20,372
21	483-10 GP Computer Hardware	32,009	-	8,576	232	-	(3,708)	-	37,109	34,559
22	483-20 GP Computer Software	3,213	-	-	-	-	(44)	-	3,169	3,191
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,208	-	2,441	-	-	-	-	4,649	3,429
26	484-00 Vehicles - Leased	29,345	-	-	-	-	(1,536)	-	27,809	28,577
27	485-10 Heavy Work Equipment	664	-	-	-	-	-	-	664	664
28	485-20 Heavy Mobile Equipment	838	-	-	-	-	-	-	838	838
29	486-00 Small Tools & Equipment	40,625	-	3,113	-	-	(2,003)	-	41,735	41,180
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	6,773	-	-	-	-	(1,460)	-	5,313	6,043
34	- Radio	5,842	-	1,112	-	-	(214)	-	6,740	6,291
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	281,004	-	23,474	232	-	(12,220)	-	292,490	286,747
37										
38	**UNCLASSIFIED PLANT**									
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,870,159	$ -	$ 134,654	$ 1,640	$ 32,934	$ (31,101)	$ -	$ 4,008,286	$ 3,939,223
43										
44	Cross Reference	- Section E-FORMULA, Sch 3(		- Section E-FORMULA, Sch 32				- Section E-FORMULA, Sch 30		
45			- Section E-FORMULA, Sch 32			- Section E-FORMULA, Sch 32				

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 31/12/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	548	549
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	78
5	178-00 Organization Expense	728	1.00%	7	-	-	391	398
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	1	-	-	98	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	227	243
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,726	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	85,788	12.50%	10,724	-	(6,015)	23,581	28,290
17	402-02 Application Software - 20%	20,513	20.00%	4,103	-	(2,997)	7,243	8,349
18	TOTAL INTANGIBLE	154,715		14,930	-	(9,012)	32,839	38,757
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	3.38%	33	-	-	143	176
24	433-00 Manufact'd Gas - Equipment	589	6.63%	39	-	-	88	127
25	434-00 Manufact'd Gas - Gas Holders	2,852	2.35%	67	-	-	238	305
26	436-00 Manufact'd Gas - Compressor Equipment	355	5.16%	18	-	-	38	56
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	735	15.89%	117	-	-	363	480
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,789	2,966
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	26,075	4.24%	1,106	-	-	10,900	12,006
36	TOTAL MANUFACTURED	68,225		1,875	-	-	25,281	27,156

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 31/12/2012	12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,299	3.74%	610	-	-	6,790	7,400
6	463-00 Measuring Structures	5,501	3.80%	209	-	(17)	1,936	2,128
7	464-00 Other Structures & Improvements	6,042	2.83%	171	-	(29)	1,891	2,033
8	465-00 Mains	813,541	1.44%	11,715	-	(372)	214,894	226,237
9	465-00 Mains - INSPECTION	8,476	14.87%	1,260	-	(1,268)	1,851	1,843
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	-	-	937	986
13	466-00 Compressor Equipment	112,851	2.87%	3,239	-	(340)	44,521	47,420
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	298	400
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,184	4.27%	1,289	-	(108)	10,440	11,621
17	467-10 Telemetering	9,434	0.31%	29	-	(22)	6,316	6,323
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	-	-	3	3
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	328	343
21	TOTAL TRANSMISSION	1,013,373		18,688	-	(2,156)	290,606	307,138
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	18,209	3.33%	606	-	(13)	4,852	5,445
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	32	37
28	473-00 Services	772,302	2.53%	19,287	-	(1,132)	142,028	160,183
29	474-00 House Regulators & Meter Installations	174,801	7.62%	12,415	-	(227)	18,625	30,813
30	477-00 Meters/Regulators Installations	29,288	4.55%	1,333	-	-	206	1,539
31	475-00 Mains	961,863	1.59%	15,450	-	(501)	299,353	314,302
32	476-00 Compressor Equipment	827	26.54%	219	(291)	-	1,235	1,163
33	477-00 Measuring & Regulating Equipment	92,345	4.75%	4,386	-	(436)	25,902	29,852
34	477-00 Telemetering	7,533	0.25%	19	-	(2)	6,063	6,080
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	212	212
36	478-10 Meters	210,465	8.05%	16,327	-	(3,492)	75,361	88,196
37	478-20 Instruments	11,889	3.15%	375	-	-	1,299	1,674
38	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,283,184		70,422	(291)	(5,803)	575,194	639,522
40								
41	**BIO GAS**							
42	472-00 Bio Gas Struct. & Improvements	137	3.60%	5	-	-	11	16
43	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	4	5
44	475-20 Bio Gas Mains – Private Land	188	1.48%	3	-	-	1	4
45	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	-	6.67%	-	-	-	-	-
47	477-10 Bio Gas Reg & Meter Equipment	575	4.75%	27	-	-	28	55
48	478-30 Bio Gas Meters	227	8.05%	18	-	-	1	19
49	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	2	2
50	TOTAL BIO-GAS	1,229		54	-	-	47	101

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 31/12/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	5.00%	$ -	$ (135)	$ -	135	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	-	5.00%	-	(4)	-	4	-
4	476-30 NG Transportation CNG Foundations	-	5.00%	-	(80)	-	80	-
5	476-40 NG Transportation LNG Foundations	-	5.00%	-	(2)	-	2	-
6	476-50 NG Transportation LNG Pumps	-	10.00%	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	-	5.00%	-	(6)	-	6	-
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-		-	(227)	-	227	-
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,490	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	10,770	4.82%	519	-	-	2,912	3,431
16	- Masonry Buildings	95,014	2.23%	2,119	-	-	15,696	17,815
17	- Leasehold Improvement	3,828	10.00%	405	-	(151)	565	819
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,567	6.67%	238	-	(245)	1,554	1,547
20	483-40 GP Furniture	21,225	5.00%	1,061	-	(1,954)	12,884	11,991
21	483-10 GP Computer Hardware	30,818	20.00%	6,163	-	(6,489)	12,281	11,955
22	483-20 GP Computer Software	3,309	12.50%	414	-	(192)	1,146	1,368
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,208	5.16%	114	-	-	601	715
26	484-00 Vehicles - Leased	28,865	0.00%	3,845	-	(1,440)	14,556	16,961
27	485-10 Heavy Work Equipment	664	8.96%	60	-	-	(175)	(115)
28	485-20 Heavy Mobile Equipment	838	18.06%	151	-	-	753	904
29	486-00 Small Tools & Equipment	39,679	5.00%	1,984	-	(963)	17,124	18,145
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	12	14
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,226	6.67%	482	-	(797)	4,368	4,053
34	- Radio	5,349	6.67%	357	-	(34)	2,678	3,001
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	275,873		17,914	-	(12,265)	86,985	92,634
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,796,597		$ 123,883	$ (518)	$ (29,236)	$ 1,011,179	$ 1,105,308
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,354)				
45	Add: Depreciation variance adjustment			1,314				
46	**Net Depreciation Expense**			$ 123,842				
47								
48	Cross Reference	- Section E-FORMULA, Sch 35		- Section E-FORMULA, Sch 21			- Section E-FORMULA, Sch 29	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	549	550
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	78	156
5	178-00 Organization Expense	728	1.00%	7	-	-	398	405
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	243	259
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,922	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	86,104	12.50%	10,763	-	(3,738)	28,290	35,315
17	402-02 Application Software - 20%	22,303	20.00%	4,461	-	(2,317)	8,349	10,493
18	TOTAL INTANGIBLE	157,018		15,326	-	(6,055)	38,757	48,028
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	3.38%	33	-	-	176	209
24	433-00 Manufact'd Gas - Equipment	729	6.63%	48	-	-	127	175
25	434-00 Manufact'd Gas - Gas Holders	2,852	2.35%	67	-	-	305	372
26	436-00 Manufact'd Gas - Compressor Equipment	355	5.16%	18	-	-	56	74
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	735	15.89%	117	-	-	480	597
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,966	3,143
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	11,039	11,357
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	27,136	4.24%	1,151	-	-	12,006	13,157
36	TOTAL MANUFACTURED	69,426		1,929	-	-	27,156	29,085

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,299	3.74%	610	-	-	7,400	8,010
6	463-00 Measuring Structures	5,490	3.80%	209	-	(17)	2,128	2,320
7	464-00 Other Structures & Improvements	6,061	2.83%	172	-	-	2,033	2,205
8	465-00 Mains	827,570	1.44%	11,917	-	(372)	226,237	237,782
9	465-00 Mains - INSPECTION	11,149	14.87%	1,658	-	(368)	1,843	3,133
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	-	-	986	1,035
13	466-00 Compressor Equipment	113,890	2.87%	3,269	-	(371)	47,420	50,318
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	400	502
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,118	4.27%	1,286	-	(108)	11,621	12,799
17	467-10 Telemetering	9,575	0.31%	30	-	(24)	6,323	6,329
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	-	-	3	3
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	343	358
21	TOTAL TRANSMISSION	1,031,198		19,317	-	(1,260)	307,138	325,195
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	18,198	3.33%	606	-	(13)	5,445	6,038
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	37	42
28	473-00 Services	786,258	2.53%	19,640	-	(1,132)	160,183	178,691
29	474-00 House Regulators & Meter Installations	174,659	7.62%	12,404	-	(4)	30,813	43,213
30	477-00 Meters/Regulators Installations	39,704	4.55%	1,806	-	-	1,539	3,345
31	475-00 Mains	976,452	1.59%	15,682	-	(501)	314,302	329,483
32	476-00 Compressor Equipment	827	26.54%	219	-	-	1,163	1,382
33	477-00 Measuring & Regulating Equipment	96,095	4.75%	4,564	-	(436)	29,852	33,980
34	477-00 Telemetering	7,963	0.25%	20	-	(2)	6,080	6,098
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	212	212
36	478-10 Meters	213,913	8.05%	16,605	-	(3,667)	88,196	101,134
37	478-20 Instruments	11,889	3.15%	375	-	-	1,674	2,049
38	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,329,623		71,926	-	(5,755)	639,522	705,693
40								
41	**BIO GAS**							
42	472-00 Bio Gas Struct. & Improvements	137	3.60%	5	-	-	16	21
43	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	5	6
44	475-20 Bio Gas Mains – Private Land	335	1.48%	5	-	-	4	9
45	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	-	6.67%	-	-	-	-	-
47	477-10 Bio Gas Reg & Meter Equipment	869	4.75%	41	-	-	55	96
48	478-30 Bio Gas Meters	447	8.05%	36	-	-	19	55
49	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	2	2
50	TOTAL BIO-GAS	1,890		88	-	-	101	189

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust- ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	5.00%	$ -	$ -	$ -	$ -	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	-	5.00%	-	-	-	-	-
4	476-30 NG Transportation CNG Foundations	-	5.00%	-	-	-	-	-
5	476-40 NG Transportation LNG Foundations	-	5.00%	-	-	-	-	-
6	476-50 NG Transportation LNG Pumps	-	10.00%	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	-	5.00%	-	-	-	-	-
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-		-	-	-	-	-
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,650	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	10,770	4.82%	519	-	-	3,431	3,950
16	- Masonry Buildings	97,501	2.23%	2,174	-	-	17,815	19,989
17	- Leasehold Improvement	3,834	10.00%	383	-	(40)	819	1,162
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,654	6.67%	244	-	(69)	1,547	1,722
20	483-40 GP Furniture	21,054	5.00%	1,053	-	(3,123)	11,991	9,921
21	483-10 GP Computer Hardware	32,009	20.00%	6,402	-	(3,708)	11,955	14,649
22	483-20 GP Computer Software	3,213	12.50%	402	-	(44)	1,368	1,726
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,208	12.50%	276	-	-	715	991
26	484-00 Vehicles - Leased	29,345	0.00%	2,755	-	(1,536)	16,961	18,180
27	485-10 Heavy Work Equipment	664	8.96%	60	-	-	(115)	(55)
28	485-20 Heavy Mobile Equipment	838	18.06%	151	-	-	904	1,055
29	486-00 Small Tools & Equipment	40,625	5.00%	2,031	-	(2,003)	18,145	18,173
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	14	16
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	6,773	6.67%	452	-	(1,314)	4,053	3,191
34	- Radio	5,842	6.67%	390	-	(214)	3,001	3,177
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	281,004		17,294	-	(12,051)	92,634	97,877
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,870,159		$ 125,880	$ -	$ (25,121)	$ 1,105,308	$ 1,206,067
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,121)				
45	Add: Depreciation variance adjustment			-				
46	**Net Depreciation Expense**			$ 124,759				
47								
48	Cross Reference	- Section E-FORMULA, Sch 38		- Section E-FORMULA, Sch 22			- Section E-FORMULA, Sch 30	

FORTISBC ENERGY INC. June 10, 2013 Section E FORMULA Schedule 45

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 31/12/2012	Adjustment	2013 PROJECTED Additions	Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 145,014	$ -	$ 6,451	$ -	$ 151,465	
4							
5	Transmission Contributions	29,058	-	2,425	-	31,483	
6							
7	Others	714	-	-	-	714	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,759	-	-	-	10,759	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	185,545	-	8,876	-	194,421	- Section E-FORMULA, Sch 29
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(42,313)	-	(4,283)	-	(46,596)	
21							
22	Transmission Contributions	(2,335)	-	(507)	-	(2,842)	
23							
24	Others	(97)	-	(97)	-	(194)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(6,398)	-	(1,332)	-	(7,730)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(51,143)	-	(6,219)	-	(57,362)	- Section E-FORMULA, Sch 29
32							
33	**NET CONTRIBUTIONS**	$ 134,402	$ -	$ 2,657	$ -	$ 137,059	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,219)			
37	Add: Depreciation variance adjustment			(280)			
38	**Net Amortization Expense**			$ (6,499)			
39				- Section E-FORMULA, Sch 21			
40							

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	Adjustment	2014 FORECAST Additions	2014 FORECAST Retirements	Balance 12/31/2014	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 151,465	$ -	$ 5,227	$ -	$ 156,692	
4							
5	Transmission Contributions	31,483	-	396	-	31,879	
6							
7	Others	714	-	-	-	714	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,759	-	-	(3,768)	6,991	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	194,421	-	5,623	(3,768)	196,276	- Section E-FORMULA, Sch 30
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(46,596)	-	(4,376)	-	(50,972)	
21							
22	Transmission Contributions	(2,842)	-	(528)	-	(3,370)	
23							
24	Others	(194)	-	(97)	-	(291)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(7,730)	-	(1,319)	3,768	(5,281)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(57,362)	-	(6,320)	3,768	(59,914)	- Section E-FORMULA, Sch 30
32							
33	**NET CONTRIBUTIONS**	$ 137,059	$ -	$ (697)	$ -	$ 136,362	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,320)			
37							
38	**Net Amortization Expense**			$ (6,320)			
39				- Section E-FORMULA, Sch 22			
40							

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (10,042)	$ -	$ 29,657	$ (7,414)	$ 22,243	$ -	$ -	$ -	$ 12,201	$ 1,079
3	Midstream Cost Reconciliation Account (MCRA)	(17,844)	-	5,507	(1,377)	4,130	-	8,999	(2,250)	(6,965)	(12,404)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(24,583)	-	(6,666)	1,667	(5,000)	-	11,551	(2,888)	(20,919)	(22,751)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,125)	-	(1,179)	295	(884)	(10)	159	(40)	(4,900)	(4,512)
6	Revelstoke Propane Cost Deferral Account	(348)	-	269	(67)	202	-	-	-	(146)	(247)
7	SCP Mitigation Revenues Variance Account	(4,154)	-	-	-	-	2,926	-	-	(1,228)	(2,691)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	22,698	-	13,350	(3,338)	10,013	(3,152)	-	-	29,559	26,128
11	NGV Conversion Grants	37	-	15	(4)	11	(28)	-	-	21	29
12	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
13	Biomethane Program Costs	324	-	200	(50)	150	(172)	-	-	302	313
14	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
15	NGT Incentives	-	-	-	-	-	-	-	-	-	-
16	Fuelling Stations Variance Account	-	-	-	-	-	-	-	-	-	-
17											
18	Non-Controllable Items Deferral Accounts										
19	Property Tax Deferral	(2,868)	-	(3,150)	788	(2,363)	594	-	-	(4,637)	(3,752)
20	Insurance Variance	45	-	93	(23)	70	-	-	-	115	80
21	Pension & OPEB Variance	15,807	-	12,607	-	12,607	(3,205)	-	-	25,209	20,508
22	BCUC Levies Variance	449	-	923	(231)	692	-	-	-	1,141	795
23	Interest Variance	(5,699)	-	(130)	33	(98)	2,600	-	-	(3,197)	(4,448)
24	Interest Variance - Funding benefits via Customer Deposits	834	-	60	(15)	45	(309)	-	-	570	702
25	Tax Variance Account	597	-	1,274	(133)	1,141	-	-	-	1,738	1,168
26	Customer Service Variance Account	(5,548)	-	(10,285)	2,571	(7,714)	-	-	-	(13,262)	(9,405)
27	Pension & OPEB Funding	(171,550)	-	(8,176)	-	(8,176)	-	-	-	(179,726)	(175,638)
28	US GAAP Pension & OPEB Funded Status	139,153	-	(14,471)	-	(14,471)	-	-	-	124,682	131,918

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	NGV for Transportation Application	140	-	50	(13)	38	(46)	-	-	132	136
4	Long Term Resource Plan Application	-	-	178	(45)	134	(90)	-	-	43	22
5	AES Inquiry Cost	619	-	2	(1)	2	(85)	-	-	536	577
6	Generic Cost of Capital Application	-	-	-	-	-	-	-	-	-	-
7	Amalgamation and Rate Design Application Costs	-	-	-	-	-	-	-	-	-	-
8											
9	Other Deferral Accounts										
10	2010-2011 Customer Service O&M and COS	21,613	-	-	-	-	(2,807)	-	-	18,806	20,210
11	Gas Asset Records Project	(60)	-	970	(243)	728	(567)	-	-	100	20
12	BC OneCall Project	(69)	-	961	(240)	721	(334)	-	-	318	125
13	Gains and Losses on Asset Disposition	27,090	-	5,890	-	5,890	(730)	-	-	32,250	29,670
14	Negative Salvage Provision/Cost	(5,965)	-	14,201	-	14,201	(16,933)	-	-	(8,697)	(7,331)
15	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
16											
17	Residual Deferred Accounts										
18	Depreciation Variance	(1,281)	-	636	-	636	-	-	-	(645)	(963)
19	SCP Tax Reassessment	(32)	-	-	-	-	-	-	-	(32)	(32)
20	BFI Costs and Recoveries	147	-	-	-	-	-	-	-	147	147
21	CNG and LNG Recoveries	(11)	-	(22)	6	(17)	-	-	-	(28)	(19)
22	2011 CNG and LNG Service Costs and Recoveries	(69)	-	-	-	-	34	-	-	(35)	(52)
23	Olympics Security Costs Deferral	188	-	-	-	-	(188)	-	-	-	94
24	IFRS Conversion Costs	238	-	-	-	-	(238)	-	-	-	119
25	2009 ROE & Cost of Capital Application	496	-	-	-	-	(168)	-	-	328	412
26	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
27	2012-2013 Revenue Requirement Application	614	-	-	-	-	(409)	-	-	205	409
28	CCE CPCN Application	150	-	-	-	-	(56)	-	-	94	122
29	Deferred Removal Costs	2,223	-	-	-	-	(2,354)	-	-	(131)	1,046
30	US GAAP Conversion Costs	(62)	-	-	-	-	(791)	-	-	(853)	(458)
31	US GAAP Transitional Costs	477	-	-	-	-	948	-	-	1,425	951
32	Earnings Sharing Mechanism	84	-	-	-	-	-	-	-	84	84
33	OH&M Recoveries from NGT	-	-	-	-	-	-	-	-	-	-
34	Tilbury Property Purchase (Subdividable Land)	-	-	-	-	-	-	-	-	-	-
35	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	-
36											
37	Total Deferred Charges for Rate Base	$ (20,287)	$ -	$ 42,765	$ (7,833)	$ 34,931	$ (25,569)	$ 20,709	$ (5,177)	$ 4,606	$ (7,840)
38											
39	Cross Reference						- Section E-FORMULA, Sch 21			- Section E-FORMULA, Sch 29	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries		Balance 12/31/2014	Mid-Year Average 2014
								Rider	Tax on Rider		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ 12,201	$ -	$ (16,268)	$ 4,067	$ (12,201)	$ -	$ -	$ -	$ -	$ 6,100
3	Midstream Cost Reconciliation Account (MCRA)	(6,965)	-	-	-	-	-	4,643	(1,161)	(3,482)	(5,223)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(20,919)	-	-	-	-	-	13,946	(3,487)	(10,460)	(15,690)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,900)	-	1,571	(393)	1,178	388	210	(53)	(3,178)	(4,039)
6	Revelstoke Propane Cost Deferral Account	(146)	-	195	(49)	146	-	-	-	-	(73)
7	SCP Mitigation Revenues Variance Account	(1,228)	-	-	-	-	791	-	-	(437)	(833)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	29,559	7,115	13,350	(3,338)	10,013	(3,801)	-	-	42,885	39,779
11	NGV Conversion Grants	21	-	15	(4)	11	(13)	-	-	19	20
12	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
13	Biomethane Program Costs	302	-	-	-	-	(302)	-	-	(0)	151
14	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
15	NGT Incentives	-	27,117	10,974	(2,744)	8,231	(3,535)	-	-	31,812	29,465
16	Fuelling Stations Variance Account	-	288	238	(60)	179	(96)	-	-	370	329
17											
18	Non-Controllable Items Deferral Accounts										
19	Property Tax Deferral	(4,637)	-	-	-	-	1,941	-	-	(2,695)	(3,666)
20	Insurance Variance	115	-	-	-	-	(115)	-	-	-	57
21	Pension & OPEB Variance	25,209	-	-	-	-	(5,039)	-	-	20,170	22,690
22	BCUC Levies Variance	1,141	-	-	-	-	(1,141)	-	-	-	571
23	Interest Variance	(3,197)	-	-	-	-	2,680	-	-	(516)	(1,857)
24	Interest Variance - Funding benefits via Customer Deposits	570	-	-	-	-	(278)	-	-	293	431
25	Tax Variance Account	1,738	-	-	-	-	(579)	-	-	1,159	1,448
26	Customer Service Variance Account	(13,262)	-	-	-	-	2,652	-	-	(10,609)	(11,936)
27	Pension & OPEB Funding	(179,726)	-	9,636	-	9,636	-	-	-	(170,090)	(174,908)
28	US GAAP Pension & OPEB Funded Status	124,682	-	(9,300)	-	(9,300)	-	-	-	115,382	120,032

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries		Balance 12/31/2014	Mid-Year Average 2014
								Rider	Tax on Rider		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ 675	$ 100	$ (25)	$ 75	$ (150)	$ -	$ -	$ 600	$ 638
3	NGV for Transportation Application	132	-	-	-	-	(132)	-	-	-	66
4	Long Term Resource Plan Application	43	-	36	(9)	27	(57)	-	-	13	28
5	AES Inquiry Cost	536	-	-	-	-	(135)	-	-	400	468
6	Generic Cost of Capital Application	-	1,354	-	-	-	(677)	-	-	677	1,016
7	Amalgamation and Rate Design Application Costs	-	1,535	-	-	-	(512)	-	-	1,023	1,279
8											
9	Other Deferral Accounts										
10	2010-2011 Customer Service O&M and COS	18,806	-	-	-	-	(2,877)	-	-	15,930	17,368
11	Gas Asset Records Project	100	-	1,113	(278)	834	(187)	-	-	748	424
12	BC OneCall Project	318	-	579	(145)	434	(164)	-	-	588	453
13	Gains and Losses on Asset Disposition	32,250	-	5,981	-	5,981	(1,682)	-	-	36,549	34,399
14	Negative Salvage Provision/Cost	(8,697)	-	12,486	-	12,486	(17,262)	-	-	(13,472)	(11,084)
15	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
16											
17	Residual Deferred Accounts										
18	Depreciation Variance	(645)	-	-	-	-	645	-	-	-	(322)
19	SCP Tax Reassessment	(32)	-	-	-	-	32	-	-	-	(16)
20	BFI Costs and Recoveries	147	(147)	-	-	-	-	-	-	-	-
21	CNG and LNG Recoveries	(28)	-	-	-	-	28	-	-	-	(14)
22	2011 CNG and LNG Service Costs and Recoveries	(35)	-	-	-	-	35	-	-	-	(17)
23	Olympics Security Costs Deferral	-	-	-	-	-	-	-	-	-	-
24	IFRS Conversion Costs	-	-	-	-	-	-	-	-	-	-
25	2009 ROE & Cost of Capital Application	328	-	-	-	-	(328)	-	-	-	164
26	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
27	2012-2013 Revenue Requirement Application	205	-	-	-	-	(205)	-	-	0	102
28	CCE CPCN Application	94	-	-	-	-	(94)	-	-	-	47
29	Deferred Removal Costs	(131)	-	-	-	-	131	-	-	-	(66)
30	US GAAP Conversion Costs	(853)	-	-	-	-	853	-	-	-	(427)
31	US GAAP Transitional Costs	1,425	-	-	-	-	(1,425)	-	-	-	713
32	Earnings Sharing Mechanism	84	(84)	-	-	-	-	-	-	-	-
33	OH&M Recoveries from NGT	-	(189)	-	-	-	189	-	-	-	(95)
34	Tilbury Property Purchase (Subdividable Land)	-	(164)	-	-	-	164	-	-	-	(82)
35	Residual Delivery Rate Riders	-	(38)	-	-	-	38	-	-	-	(19)
36											
37	Total Deferred Charges for Rate Base	$ 4,606	$ 37,461	$ 30,705	$ (2,976)	$ 27,729	$ (30,216)	$ 18,799	$ (4,700)	$ 53,678	$ 47,872
38											
39	Cross Reference						- Section E-FORMULA, Sch 22			- Section E-FORMULA, Sch 30	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 31/12/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ 18	$ 36
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	26,075	0.37%	99	-	-	-	94	193
5	TOTAL MANUFACTURED	47,534		183	-	-	-	178	361
5									
6	**TRANSMISSION PLANT**								
7	462-00 Compressor Structures	16,299	0.18%	27	-	-	-	27	54
8	463-00 Measuring Structures	5,501	0.18%	10	-	-	-	2	12
9	464-00 Other Structures & Improvements	6,042	0.14%	8	-	-	-	8	16
10	465-00 Mains	813,541	0.14%	1,175	-	(1,960)	-	968	183
11	466-00 Compressor Equipment	112,851	0.28%	333	-	-	-	314	647
12	467-00 Measuring & Regulating Equipment	30,184	0.18%	51	-	-	-	18	69
13	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	3	6
14	TOTAL TRANSMISSION	984,763		1,607	-	(1,960)	-	1,340	987
15									
16	**DISTRIBUTION PLANT**								
17	472-00 Structures & Improvements	18,209	0.16%	27	-	-	-	27	54
18	473-00 Services	772,302	1.24%	8,982	-	(8,754)	-	(2,044)	(1,816)
19	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
20	474-00 House Regulators & Meter Installations	174,801	0.75%	1,188	-	(2,659)	-	4,040	2,569
21	477-00 Meters/Regulators Installations	29,288	0.75%	173	-	-	-	57	230
22	475-00 Mains	961,863	0.33%	3,107	-	(828)	-	1,798	4,077
23	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
24	476-00 Compressor Equipment	827	11.43%	165	-	-	-	165	330
25	477-00 Measuring & Regulating Equipment	92,345	0.52%	468	-	-	-	389	857
26	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
27	478-10 Meters	210,465	0.50%	1,031	-	-	-	14	1,045
28	TOTAL DISTRIBUTION	2,260,261		15,141	-	(12,241)	-	4,446	7,346
29									
30	**BIO GAS**								
31	475-20 Bio Gas Mains – Private Land	188	0.33%	1	-	-	-	-	1
32	478-30 Bio Gas Meters	227	0.50%	-	-	-	-	-	-
33	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
34	TOTAL BIO-GAS	437		2	-	-	-	1	3
35									
36	TOTALS	$ 3,292,994		$ 16,933	$ -	$ (14,201)	$ -	$ 5,965	$ 8,697
37									
38	Cross Reference	-FORMULA, Sch 35							- Section E-FORMULA, Sch 48

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Salvage Rate %	2014 DEPRECIATION Provision (Cr.)	Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2013	Ending 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ 36	$ 54
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	132	198
4	449-00 Local Storage Equipment (Tilbury)	27,136	0.37%	100	-	-	-	193	293
5	TOTAL MANUFACTURED	48,595		184	-	-	-	361	545
5									
6	**TRANSMISSION PLANT**								
7	462-00 Compressor Structures	16,299	0.18%	29	-	-	-	54	83
8	463-00 Measuring Structures	5,490	0.18%	10	-	-	-	12	22
9	464-00 Other Structures & Improvements	6,061	0.14%	8	-	-	-	16	24
10	465-00 Mains	827,570	0.14%	1,159	-	-	-	183	1,342
11	466-00 Compressor Equipment	113,890	0.28%	319	-	-	-	647	966
12	467-00 Measuring & Regulating Equipment	30,118	0.18%	54	-	-	-	69	123
13	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	6	9
14	TOTAL TRANSMISSION	999,774		1,582	-	-	-	987	2,569
15									
16	**DISTRIBUTION PLANT**								
17	472-00 Structures & Improvements	18,198	0.16%	29	-	-	-	54	83
18	473-00 Services	786,258	1.24%	9,252	-	(8,928)	-	(1,816)	(1,492)
19	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
20	474-00 House Regulators & Meter Installations	174,659	0.75%	1,189	-	(2,713)	-	2,569	1,045
21	477-00 Meters/Regulators Installations	39,704	0.75%	298	-	-	-	230	528
22	475-00 Mains	976,452	0.33%	3,110	-	(845)	-	4,077	6,342
23	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
24	476-00 Compressor Equipment	827	11.43%	95	-	-	-	330	425
25	477-00 Measuring & Regulating Equipment	96,095	0.52%	500	-	-	-	857	1,357
26	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
27	478-10 Meters	213,913	0.50%	1,019	-	-	-	1,045	2,064
28	TOTAL DISTRIBUTION	2,306,269		15,492	-	(12,486)	-	7,346	10,352
29									
30	**BIO GAS**								
31	475-20 Bio Gas Mains – Private Land	335	0.33%	1	-	-	-	1	2
32	478-30 Bio Gas Meters	447	0.50%	2	-	-	-	-	2
33	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
34	TOTAL BIO-GAS	804		3	-	-	-	3	6
35									
36	TOTALS	$ 3,355,442		$ 17,261	$ -	$ (12,486)	$ -	$ 8,697	$ 13,472
37									
38	Cross Reference	-FORMULA, Sch 38							- Section E-FORMULA, Sch 50

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	2013 PROJECTED Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 9,202	$ 7,458	$ 8,528	$ 8,528	$ 1,070	- Section E-FORMULA, Sch 55
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(6,282)	(4,588)	(5,760)	(5,760)	(1,172)	
9							
10	Withholdings From Employees	(4,819)	(5,163)	(4,359)	(4,359)	804	
11							
12	Subtotal	(1,899)	(2,293)	(1,591)	(1,591)	702	- Section E-FORMULA, Sch 29
13							
14	**Other Working Capital Items**						
15	Construction Advances	(439)	(620)	-	-	620	
16	Transmission Line Pack Gas	3,924	3,566	2,846	2,846	(720)	
17	Gas in Storage	97,294	97,242	78,766	78,766	(18,476)	
18	Inventory - Materials & Supplies	637	1,434	1,509	1,509	75	
19							
20	Subtotal	101,416	101,622	83,121	83,121	(18,501)	- Section E-FORMULA, Sch 29
21							
22	Total	$ 99,517	$ 99,329	$ 81,530	$ 81,530	$ (17,799)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Existing 2013 Rates	2014 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 8,528	$ 9,700	$ 9,672	$ 1,144	- Section E-FORMULA, Sch 55
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(5,760)	(5,459)	(5,459)	301	
9						
10	Withholdings From Employees	(4,359)	(4,489)	(4,489)	(130)	
11						
12	Subtotal	(1,591)	(248)	(276)	1,315	- Section E-FORMULA, Sch 30
13						
14	**Other Working Capital Items**					
15	Construction Advances	-	-	-	-	
16	Transmission Line Pack Gas	2,846	2,662	2,662	(184)	
17	Gas in Storage	78,766	74,841	74,841	(3,925)	
18	Inventory - Materials & Supplies	1,509	1,536	1,536	27	
19						
20	Subtotal	83,121	79,039	79,039	(4,082)	- Section E-FORMULA, Sch 30
21						
22	Total	$ 81,530	$ 78,791	$ 78,763	$ (2,767)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Days	2013 Expenses	2013 Cash Working Capital	2014 Days	2014 Expenses	2014 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CASH WORKING CAPITAL**							
2								
3	Revenue Lag Days	39.0			39.0			- Section E-FORMULA, Sch 56
4	Expense Lead Days	35.8			35.4			- Section E-FORMULA, Sch 57
5								
6	Net Lead/(Lag) Days	3.2	$ 972,689	$ 8,528	3.6	$ 983,496	$ 9,700	- Section E-FORMULA, Sch 53
7								- Section E-FORMULA, Sch 54
8								
9								
10	**CASH WORKING CAPITAL, REVISED RATES**							
11								
12	Revenue Lag Days	39.0			39.0			- Section E-FORMULA, Sch 56
13	Expense Lead Days	35.8			35.4			- Section E-FORMULA, Sch 57
14								
15	Net Lead/(Lag) Days	3.2	$ 972,689	$ 8,528	3.6	$ 980,644	$ 9,672	- Section E-FORMULA, Sch 53
16								- Section E-FORMULA, Sch 54
17								
18								
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ (28)	
20								
21								
22								
23	Cash working capital = Col. 2 x Col. 3 / 365 days							

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Revenue At 2013 Rates	2013 Lag Days Service to Collection	2013 Dollar Days	2014 Revenue At 2013 Rates	2014 Lag Days Service to Collection	2014 Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**REVENUE**							
2								
3	Gas Sales and Transportation Service Revenue							
4	Residential and Commercial	$ 1,013,232	38.3	$ 38,850,744	$ 1,003,452	38.3	$ 38,476,516	- Section E-FORMULA, Sch 10
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	76,551	45.1	3,451,304	78,560	45.1	3,542,123	
6	NGV Fuel - Stations	467	41.7	19,454	467	41.7	19,454	
7								
8	Rate 16, Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	56,374	42.9	2,416,294	62,894	42.6	2,679,862	
9								
10	Total Gas Sales	1,146,623	39.0	44,737,796	1,145,372	39.0	44,717,955	
11	Other Revenues							
12	Late Payment Charges	2,134	38.3	81,736	2,114	38.3	80,962	- Section E-FORMULA, Sch 12-13
13	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Section E-FORMULA, Sch 12-13
14	Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Section E-FORMULA, Sch 12-13
15	Other Utility Income	132	35.4	4,670	649	43.2	28,048	- Section E-FORMULA, Sch 12-13
16								
17								
18	Total Revenue	$ 1,151,590	39.0	$ 44,927,654	$ 1,150,850	39.0	$ 44,930,976	
19								
20								
21	**REVENUE, REVISED RATES**							
22								
23	Gas Sales and Transportation Service Revenue							
24	Residential and Commercial	$ 1,013,232	38.3	$ 38,850,744	$ 994,508	38.3	$ 38,133,525	- Section E-FORMULA, Sch 10
25	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	76,551	45.1	3,451,304	77,387	45.1	3,489,157	
26	NGV Fuel - Stations	467	41.7	19,454	463	41.7	19,288	
27								
28	Rate 16, Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	56,374	42.9	2,416,294	62,403	42.6	2,658,001	
29								
30	Total Gas Sales	1,146,623	39.0	44,737,796	1,134,760	39.0	44,299,971	
31	Other Revenues							
32	Late Payment Charges	2,134	38.3	81,736	2,114	38.3	80,962	- Section E-FORMULA, Sch 12-13
33	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Section E-FORMULA, Sch 12-13
34	Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Section E-FORMULA, Sch 12-13
35	Other Utility Income	132	35.4	4,670	649	43.2	28,048	- Section E-FORMULA, Sch 12-13
36								
37								
38	Total Revenue	$ 1,151,590	39.0	$ 44,927,654	$ 1,140,238	39.0	$ 44,512,992	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars		2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	2014 Amount	2014 Lead Days Expense to Payment	2014 Dollar Days	Cross Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**EXPENSES**								
2									
3	Operating And Maintenance								- Section E-FORMULA, Sch 3
4	Expenses		$ 198,578	25.5	$ 5,063,739	$ 202,307	25.5	$ 5,158,829	- Section E-FORMULA, Sch 4
5	Transportation Costs		-	0.0	-	-	0.0	-	
6	Gas Purchases (excl Royalty Credits)		505,695	40.2	20,328,939	499,685	40.2	20,087,337	
7									
8	Taxes Other Than Income								- Section E-FORMULA, Sch 19
9	Property Taxes		48,089	2.0	96,178	48,797	2.0	97,594	- Section E-FORMULA, Sch 20
10	Franchise Fees		8,143	420.3	3,422,503	8,021	420.3	3,371,226	
11	Carbon Tax		169,756	29.1	4,939,904	171,305	29.1	4,984,978	
12	HST - Net	*	6,640	38.8	257,623			-	
13	PST Component of HST (REC)	*	(2,353)	33.8	(79,530)			-	
14	GST - Net	**	7,349	38.8	285,145	9,789	38.8	379,829	
15	PST - Net	**	3,284	37.1	121,854	4,110	37.1	152,487	
16	Income Tax		27,508	15.2	418,122	39,481	15.2	600,111	- Section E-FORMULA, Sch 23
17									- Section E-FORMULA, Sch 24
18	Total Expenses		$ 972,689	35.8	$ 34,854,477	$ 983,496	35.4	$ 34,832,391	
19									
20									
21	**EXPENSES, REVISED RATES**								
22									
23	Operating And Maintenance								- Section E-FORMULA, Sch 3
24	Expenses		$ 198,578	25.5	$ 5,063,739	$ 202,307	25.5	$ 5,158,829	- Section E-FORMULA, Sch 4
25	Transportation Costs		-	0.0	-	-	0.0	-	
26	Gas Purchases (excl Royalty Credits)		505,695	40.2	20,328,939	499,685	40.2	20,087,337	
27									
28	Taxes Other Than Income								- Section E-FORMULA, Sch 19
29	Property Taxes		48,089	2.0	96,178	48,797	2.0	97,594	- Section E-FORMULA, Sch 20
30	Franchise Fees		8,143	420.3	3,422,503	7,945	420.3	3,339,283	
31	Carbon Tax		169,756	29.1	4,939,904	171,305	29.1	4,984,978	
32	HST - Net	*	6,640	38.8	257,623			-	
33	PST Component of HST (REC)	*	(2,353)	33.8	(79,530)			-	
34	GST - Net	**	7,349	38.8	285,145	9,699	38.8	376,306	
35	PST - Net	**	3,284	37.1	121,854	4,078	37.1	151,306	
36	Income Tax		27,508	15.2	418,122	36,828	15.2	559,786	- Section E-FORMULA, Sch 23
37									- Section E-FORMULA, Sch 24
38	Total Expenses		$ 972,689	35.8	$ 34,854,477	$ 980,644	35.4	$ 34,755,419	
39									

40 * January to March 2013 is computed at 25% of 2013 Approved cash outflows.
41 ** April to December 2013 is computed at 75% of 2013 Projected cash outflows.

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Total DIT Liability- After Tax	(210,925)	(215,501)	(216,513)	(216,167)	
2						
3	Tax Gross Up	(70,308)	(71,834)	(72,171)	(72,056)	
4						
5	DIT Liability/Asset - End of Year	(281,233)	(287,335)	(288,683)	(288,222)	
6						
7	DIT Liability/Asset - Opening Balance	(282,624)	(277,382)	(281,233)	(288,683)	
8						
9	DIT Liability/Asset - Mid Year	(281,929)	(282,359)	(284,958)	(288,453)	
10						
11	Cross Reference			- Section E-FORMULA, Sch 29		
12					- Section E-FORMULA, Sch 30	
13						
14	Note: * Excludes Land, Software CIAC, and WIP.					

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Capitalization	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 RATES							
2	Long-Term Debt		$ 1,576,786	58.37%	6.87%	4.01%	$ 108,280	- Section E-FORMULA, Sch 61
3	Unfunded Debt		44,139	1.63%	3.50%	0.06%	1,545	
4	Preference Shares			0.00%		0.00%	-	
5	Common Equity		1,080,617	40.00%	10.10%	4.04%	109,171	
6								
7			$ 2,701,542	100.00%		8.11%	$ 218,996	- Section E-FORMULA, Sch 29
8								
9								
10								
11	2013 REVISED RATES - PROJECTED							
12	Long-Term Debt		$ 1,576,786	58.37%	6.87%	4.01%	$ 108,280	- Section E-FORMULA, Sch 61
13	Unfunded Debt	$ 44,139						
14	Adjustment, Revised Rates	-	44,139	1.63%	3.50%	0.06%	1,545	
15	Preference Shares		-	0.00%	0.00%	0.00%	-	
16	Common Equity		1,080,617	40.00%	10.10%	4.04%	109,171	
17								- Section E-FORMULA, Sch 3
18			$ 2,701,542	100.00%		8.11%	$ 218,996	- Section E-FORMULA, Sch 29

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Capitalization	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2014 AT 2013 RATES							
2	Long-Term Debt		$ 1,564,198	55.89%	6.84%	3.82%	$ 106,944	- Section E-FORMULA, Sch 62
3	Unfunded Debt		156,956	5.61%	1.75%	0.10%	2,747	
4	Preference Shares			0.00%		0.00%	-	
5	Common Equity		1,077,471	38.50%	9.49%	3.65%	102,236	
6								
7			$ 2,798,625	100.00%		7.57%	$ 211,927	- Section E-FORMULA, Sch 30
8								
9								
10								
11	2014 REVISED RATES							
12	Long-Term Debt		$ 1,564,198	55.89%	6.84%	3.82%	$ 106,944	- Section E-FORMULA, Sch 62
13	Unfunded Debt	$ 156,956						
14	Adjustment, Revised Rates	(17)	156,939	5.61%	1.75%	0.10%	2,746	
15	Preference Shares		-	0.00%	0.00%	0.00%	-	
16	Common Equity		1,077,460	38.50%	8.75%	3.37%	94,278	
17								- Section E-FORMULA, Sch 4
18			$ 2,798,597	100.00%		7.29%	$ 203,968	- Section E-FORMULA, Sch 30

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
FOR THE YEAR ENDING DECEMBER 31, 2013 *** APPROVED ***
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,889	*	10.461%	158,117	16,541
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Oct-2011	1-Oct-2021	4.500%	100,000	1,000	99,000		4.626%	100,000	4,626
13											
14	LILO Obligations - Kelowna								6.445%	21,892	1,411
15	LILO Obligations - Nelson								7.872%	3,519	277
16	LILO Obligations - Vernon								9.153%	10,466	958
17	LILO Obligations - Prince George								8.067%	27,085	2,185
18	LILO Obligations - Creston								7.218%	2,577	186
19											
20	Vehicle Lease Obligation								5.685%	13,510	768
21											
22	Sub-Total									$ 1,582,121	$ 108,646
23	Less: Fort Nelson Division Portion of Long Term Debt									5,335	366
24	Total									$ 1,576,786	$ 108,280
25											
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.87%
27	**Includes adjustment of $843 for BC Hydro Premium (Series B).										
28	Cross Reference									- Section E-FORMULA, Sch 59	

FORTISBC ENERGY INC. June 10, 2013 Section E FORMULA Schedule 62

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	158,975	**	10.461%	161,203	16,863
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,234	98,766		6.645%	100,000	6,645
11	2011 Medium Term Debt Issue - Series 25	9-Dec-2011	9-Dec-2041	4.250%	100,000	1,410	98,590		4.334%	100,000	4,334
12											
13	LILO Obligations - Kelowna								6.469%	20,963	1,356
14	LILO Obligations - Nelson								7.983%	3,382	270
15	LILO Obligations - Vernon								9.276%	10,037	931
16	LILO Obligations - Prince George								8.182%	26,057	2,132
17	LILO Obligations - Creston								7.330%	2,483	182
18											
19	Vehicle Lease Obligation								2.281%	11,006	251
20											
21	Sub-Total									$ 1,580,086	$ 108,031
22	Less: Fort Nelson Division Portion of Long Term Debt									5,335	365
23	Less: NGT Class of Service Portion of Long Term Debt									10,553	722
24	Total									$ 1,564,198	$ 106,944
25											
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.84%
27	**Includes adjustment of $3,929 for BC Hydro Premium (Series B).										
28	Cross Reference									- Section E-FORMULA, Sch 60	

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2014 Volumes (TJ)	2014 Amortization ($000s)	2014 Amortization of RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)
1	**RSAM (Rider 5) Calculation**			
2				
3	Schedule 1 - Residential	69,511.7		($0.118)
4	Schedule 2 - Small Commercial	24,246.8		($0.118)
5	Schedule 3 - Large Commercial	17,253.0		($0.118)
6	Schedule 23 - Large Commercial Transportation	8,721.3		($0.118)
7				
8		119,732.8	($14,156) (1)	
9				
10				
11	Note 1: RSAM Rider Change			
12				
13	In 2013, FortisBC Energy forecasts that there will be approximately $-5 million (net-of-tax) of RSAM additions.			
14	After offsetting the 2013 RSAM Rider recovery, the RSAM account including interest is now projected to be a			
15	credit balance of $-21.2 million on a net-of-tax basis by the end of 2013. The RSAM balance is to be amortized			
16	over two years. Accordingly, the net-of-tax RSAM balance to be amortized in 2014 is a credit of			
17	$-10.6 million. On a pre-tax basis, this amounts to $14.2 million or a refund to customers of $0.118/GJ			
18	in 2014, which is a $0.019 increase from the existing charge of ($0.099)/GJ.			
19				
20				
21				
22	2014 Net-Of-Tax Amortization = 1/2 of Projected December 31, 2013 RSAM Balance			
23	= 1/2 * ($-20,919 RSAM + $-320 RSAM Interest)			
24	= 1/2 * $-21,239			
25	= $-10,620 Net-of-tax amortization			
26				
27	2014 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate)			
28	= $-10,620 / (1 - 25%)			
29	= $-14,156 Pre-tax amortization			