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July 5, 2013

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

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

Enclosed please find FBC'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 INC.

Original signed:

Dennis Swanson

Attachments

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

FORTISBC

FORTISBC INC.

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

Volume 1 - Application

July 5, 2013

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A: OVERVIEW AND INTRODUCTION

1. APPLICATION OVERVIEW

1.1 INTRODUCTION

FortisBC Inc. (FBC 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.

FBC's primary objectives for its PBR Plan are:

1. To reinforce FBC'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.

FBC's proposed PBR Plan builds on the successful components of its most recent PBR plan, which was approved for 2007 – 2008 and extended for 2009 – 2011 (the 2007 Plan), with improvements to a number of elements. The proposed PBR Plan establishes incentive for operating and maintenance (O&M) expense, similar to the 2007 Plan, and introduces a formula-based determination and incentive for capital expenditures. These are the two elements of cost of service over which the Company has the greatest control. The formula results in targeted levels of spending in these areas that are lower than FBC's combined forecast of O&M and capital costs over the five year period as set out in Section B. 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 FBC achieves greater efficiencies than represented by the formula-based targets. For those items over which FBC has limited or no control, the PBR Plan utilizes flow-through accounts and annual forecasts to ensure that customers only pay the actual costs incurred. These flow through accounts protect the customers from forecast variances on those items that are outside the Company's control. The PBR Plan provides "off-ramps" should financial results fall outside a band of reasonableness or if there is a serious, sustained and unjustified degradation of service quality.

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 to 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 reforecast annually.
Controllable Expenses – Capital	The same formula as O&M will be used. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%.
Non-Controllable Items - Flow Through Expenses and Revenues	Revenues and non-controllable costs, after being re forecast each year, are flowed through in rates 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 Plan includes an equal earnings sharing between Customers and the Shareholder for returns above or below the approved return on equity.
Efficiency Carry-Over Mechanism	An 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	9 SQIs (5 SQIs with a target benchmark and 4 informational measures) are proposed that deal with emergency response, customer service, employee safety and system reliability.
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 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 Plan.

FBC's PBR expert, Black and Veatch (B&V),[1] has studied the available PBR methodologies and provided its recommendations on FBC's proposed PBR model (Appendix D1, which contains a comparison of recent Canadian PBR plans). B&V concludes that there is no one "right" PBR model, and that the framework adopted for FBC should be in keeping with FBC'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 FBC. FBC's proposed PBR Plan incorporates a more aggressive "stretch" productivity factor than is

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

suggested by B&V's research of other North American utilities (Appendix D2, Estimating Total Factor Productivity).

Overall, FBC believes that the proposed PBR Plan is an appropriate model that will encourage FBC 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, which has 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 FBC, with the exception that it regards the "stretch" productivity factor as being more aggressive than is warranted. B&V regards the appropriate productivity factor as being approximately zero, based on the Total Factor Productivity (TFP) study it conducted and the specific elements of the proposed PBR Plan. In other words, FBC's proposal is more favourable to customers than B&V would recommend. FBC is nonetheless willing to incorporate a stretch factor and to attempt to achieve the 0.5 percent productivity factor proposed 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.

Also proposed in this application is a mechanism for mitigating rate variability over the period of the proposed PBR Plan. FBC proposes that the revenue requirements forecast in this Application for the 2014-2018 period be levelized, exclusive of changes arising from the Annual Reviews, future projects to be approved by way of applications for Certificates of Public Convenience and Necessity (CPCNs) and of the Commission decision regarding the current Stage 2 Generic Cost of Capital proceeding. This rate stabilization mechanism addresses the BCUC's direction to FBC in its 2012 decision regarding future power supply costs[2]. The mechanism not only mitigates rate variability, averaging 3.3 percent annually based on current forecasts of revenue requirements over the PBR Period, but results in an overall lower rate increase over the period, as explained in Section B7.1.

Although in this Application FBC is requesting approval only of 2014 rates, forecasts of load and sales revenue, power purchase expense, other income, O&M, and capital expenditures for the full 2014-2018 term (the PBR Period) are provided in Section C. The 2014 through 2018 O&M and capital expenditure forecasts contained in Sections C4 and C5 are included for reference purposes (O&M and capital to be included in rates are set out in Section B6), and represent a high level forecast of future trends and upcoming challenges for FBC. As FBC's proposed rates are based on the formulaic calculations, FBC's cost of service forecasts are not the focus of this proceeding. FBC has provided an historical review of O&M expenditures since 2010. This historical review demonstrates the significant cost pressures that FBC has faced in recent years. Nevertheless, FBC's focus on cost management and productivity has resulted in consistent inflation-adjusted O&M expenditures on a per customer basis. To the extent possible,

[2] Order E-15-12 dated May 25, 2012 accepting the Waneta Capacity Agreement as an Energy Supply Agreement pursuant to Section 71 of the Utilities Commission Act.

FBC has also incorporated sustainable savings into the 2013 Base O&M to which the O&M formula in the PBR Plan will be applied.

Section D of the Application 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. FBC is proposing to align certain of its accounting practices and policies and the treatment of various cost accounts, where reasonable and appropriate to the circumstances of the utilities, with those of FortisBC Energy Inc. (FEI or the gas utility). Such alignment will contribute to internal consistency and promote efficiencies, including efficiencies in the review of the companies' regulatory applications.

As set out in Appendix H, FBC seeks acceptance of a Demand Side Management (DSM) portfolio over a five year term. The DSM expenditures under FBC's DSM Plan (Attachment H1) are lower than the expenditure levels approved for 2012 and 2013. This reduction is driven by a marked decrease in the Long Run Marginal Cost (LRMC), which is used in the evaluation of DSM measures and programs pursuant to regulation. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation. FBC is also seeking approval for a change in the amortization period of existing and future DSM expenditures from 10 years to 15 years, as set out in Appendix H.

Section E provides the financial schedules filed in support of the 2014 rates proposed in this Application and Appendix G includes summary schedules for the 2015–2018 period, taking into account the rate stabilization proposal.

FBC notes that in its Decision in the 2012–2013 RRA of the FortisBC Energy Utilities (FEU),[3] the Commission made the following comments in its discussion of FEU's 2004 PBR 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…"*

[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.

FBC believes its own 1996 and 2007 plans and the negotiated settlement processes that produced them were also successful. While FBC's proposed PBR Plan is similar to its 2007 Plan, FBC's going-in rates for this PBR Plan already incorporate substantial productivity savings achieved during the 2007–2011 PBR period, and those that have been realized in the 2012-2013 period through a renewed productivity focus. As a result, it will be challenging for this PBR Plan to produce the same level of savings that were realized under the 2007 Plan. Nevertheless, FBC 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.

1.1.1 Recent and Pending BCUC Decisions

The actual and forecast amounts used to project rates for 2014-2018 in this application include FBC's recent acquisition of the electricity distribution assets of the City of Kelowna and the Commission's decision in the Stage 1 Generic Cost of Capital (GCOC) proceeding, in addition to the impacts of the Company's Advanced Metering Infrastructure Project and a new Power Purchase Agreement with BC Hydro.

1.1.1.1 City of Kelowna

Commission Order C-4-13 approved FBC's application to acquire the utility assets owned by its previous wholesale customer, the City of Kelowna. The City's approximately 14,500 customers became direct customers of FBC, effective March 31, 2013. The transaction gave rise to a customer benefit of $2.6 million and an approximate 1.5 percent cumulative rate decrease.

1.1.1.2 Stage 1 Generic Cost of Capital

In determining revenue requirements in this Application, FBC has taken into account the impact of the Commission's decision in Order G-75-13 in the Stage 1 Generic Cost of Capital (GCOC) proceeding, which set the return on equity (ROE) of the benchmark utility at 8.75 percent, resulting in a decrease in FBC's ROE from the interim 9.90 percent to 9.15 percent for 2013. The Company is requesting that the Commission approve its existing rates as permanent, effective January 1, 2013, and that the Stage 1 GCOC impact be deferred and returned to customers in 2014[4]. Any further changes to FBC's revenue requirements would be the subject of a flow-through as soon as practicable following a decision in the Stage 2 GCOC proceeding.

1.1.1.3 Advanced Metering Infrastructure

On July 26, 2012, FBC filed an application for a CPCN to develop and deploy its Advanced Metering Infrastructure (AMI) Project[5], which is a key element in improving the ability of both the utility and its customers to manage the cost of electricity. Following a written and limited oral

[4] Section D4.3.4
[5] See Sections C4.18 and C5.6.9

public hearing which concluded in May 2013, the Company anticipates approval of the AMI Project shortly.

1.1.1.4 Power Purchase Agreement

BC Hydro and FBC have recently concluded a power purchase agreement (the New PPA) to replace the existing agreement which expires on September 30, 2013. BC Hydro filed an application on May 24, 2013 for approval of the New PPA, which forms the basis of the forecast power purchase expense[6] in this application from October 1, 2013 forward, and which is expected to be approved during the regulatory review of this application.

FBC has not included in this application the revenue requirements impacts of capital projects for which it intends to file CPCN applications in future. Section C5.7 contains a summary of future CPCN projects during the PBR term, for informational purposes. The Company will bring forward additional information in regard to the timing of CPCN applications as applicable in the Annual Reviews.

Should the AMI project or the new PPA not be approved, or the terms of the AMI approval differ materially from the application so as to impact revenue requirements, FBC will file an evidentiary update to this Application. FBC would also file an update if any other events, such as the effect of the actual 2013 debt issuance on 2014 interest expense, as identified in Section D1, or the proposed corporate income tax rate is enacted, as identified in Section D2.1, occur and have a material impact on revenue requirements.

[6] Section C2

2. APPROVALS SOUGHT

In this Application, FBC 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.

2.1 *PBR PLAN AND RATE STABILIZATION*

1. Approval pursuant to sections 59 to 61 of the Utilities Commission Act (the Act) of the PBR mechanisms set out in Section B of this Application for setting rates for the years 2014-2018;
2. Approval pursuant to sections 50 to 61 of the Act for the rate stabilization mechanism set out in Section B7.1 of this Application for setting rates for the years 2014-2018;

2.2 *GENERAL RATE INCREASES*

3. Approval of the existing interim rates as permanent rates effective January 1, 2013;
4. Approval pursuant to sections 59 to 61 of the Act of permanent rates for all customers effective January 1, 2014, resulting in an increase of 3.3 percent compared to 2013 rates. The general rate increase will be applied to the Residential Conservation Rate (Rate Schedule 1) in accordance with the pricing principles[7] set out in Order G-3-12;
5. Approval to flow through during 2014 any increase or decrease arising from a decision in the Generic Cost of Capital Stage 2 proceeding, as soon as practicable following a decision of the Commission and the effective date of such a decision;

2.3 *DEFERRAL ACCOUNTS*

6. Approval pursuant to sections 59 to 61 of the Act for the rate base treatment and financing of deferral accounts, as set out in Section D3.2;
7. Approval of financing costs for 2013 at FBC's Weighted Average Cost of Capital for the six deferral accounts approved by Order G-23-13, as set out in Sections D4.438 to D4.4.13;
8. Approval pursuant to sections 59 to 61 of the Act of the discontinuance, modification, and creation of deferral accounts, as applicable, and the amortization and disposition of balances of deferral accounts, as set out in Section D4 and Appendix F4 of the Application and summarized in the following table;

[7] For the years 2012-2015:

a. The Customer Charge is exempt from general rate increases;
b. The Block 1 rate is subject to the general rate increase; and
c. The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue.

Table A2-1: Summary of Deferral Account Requests

Type of Change	Account Name	Reference
New Account – Rate Base	Rate Stabilization Deferral Mechanism (RSDM)	Section D4.3.1; amortization period of 5 years commencing January 1, 2014.
	Earnings Sharing Mechanism (ESM) Deferral	Section D4.3.2; balance at December 31 of each year to be amortized into rates in the subsequent year
	BC Hydro Application for a Power Purchase Agreement with FBC (RS 3808)	Section D4.3.3; amortization in 2014.
	Generic Cost of Capital Revenue Requirement Impact	Section D4.3.4; amortization in 2014.
	Insurance Expense Variance	Section D4.3.5; amortization in following year.
	Interest Expense Variance	Section D4.3.6, amortization period of 3 years
	Tax Variance	Section D4.3.7; amortization in following year.
	Property Tax Variance	Section D4.3.8; amortization period of 3 years.
	2014 – 2018 Annual Reviews	Section D4.3.9; amortization period of 1 year,
New Account – Non Rate Base	CPCN Projects Preliminary Engineering	Section D4.7.4; transfer to capital project upon approval.
Amortization Period – New or Modified Rate Base	Demand Side Management	Section D4.4.1:change in amortization period from 10 years to 15 years
	On-Bill Financing Pilot Program	Section D4.4.2; change in amortization period from 10 years to 15 years.
	2014 - 2018 PBR Application	Section D4.4.3; amortization over 5 years beginning January 1, 2014.
	Pension and OPEB Expense Variance	Section D4.4.4; change from 3 year amortization period to an 11 year amortization period (EARSL), commencing January 1, 2014
	City of Kelowna Acquisition Customer Benefit	Section D4.4.5; amortization in 2014.
	City of Kelowna Acquisition Legal and Regulatory Costs	Section D4.4.66; amortization in 2014.
	2014 - 2018 Capital Expenditure Plan (Pre Engineering Costs)	Section D4.4.77; amortization period of 2 years beginning in 2014
	BCUC Generic Cost of Capital Proceeding	Section D4.4.88; amortization over 2 years beginning in 2014.
	BCUC Inquiry into the MRS Program	Section D4.4.99; amortization in 2014.

Type of Change	Account Name	Reference
	Kettle Valley Expenditure Review	Section D4.4.1010; amortization in 2014.
	Transmission Customer Rate Design	Section D4.4.1111; amortization in 2014
	2012 Mandatory Reliability Standards Audit	Section D4.4.12: amortization in 2014.
	Mandatory Reliability Standards 2012 -2013 Incremental O&M Expense	Section D4.4.133; amortization in 2014.
Other Rate Base	On-Bill Financing Participant Loans	Section D4.5.2; 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
	Debt Issue Costs	Section D4.5.9; debt issue costs will be incorporated into one account.
Discontinuance	Kelowna Bulk Transformer Capacity Addition Project	Section D4.5.3; discontinuation of this account effective January 1, 2015.
	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	Section D4.5.4; discontinuation of this account effective January 1, 2015.
	Negotiation of new PPA between BC Hydro and FBC	Section D4.5.5; discontinuation of this account effective January 1, 2015.
	Right of Way Encroachment Litigation	Section D4.5.6; discontinuation of this account effective January 1, 2015
	Trail Office Lease Cost	Section D4.5.7; discontinuation of this account effective January 1, 2014.
	Trail Office Rental to School District 20	Section D4.5.8; discontinuation of this account effective January 1, 2014.
	2011 Flow-Through and ROE Sharing Mechanism Adjustments	Section D4.6; discontinuation of this account effective January 1, 2015.
	2012 Deferred Revenue	Section D4.6; discontinuation of this account effective January 1, 2014.
	Harmonized Sales Tax Removal/ Provincial Sales Tax Implementation	Section D4.6; discontinuation of this account effective January 1, 2015.
	Cost of Service and Rate Design Application	Section D4.6; discontinuation of this account effective January 1, 2015.
	2012 - 2013 Revenue Requirements Application and 2012 Integrated System Plan	Section D4.6; discontinuation of this account effective January 1, 2015.
	2011 Revenue Requirement Application Costs	Section D4.6; discontinuation of this account effective January 1, 2014.

Type of Change	Account Name	Reference
	BC Hydro Waneta Transaction Proceeding	Section D4.6; discontinuation of this account effective January 1, 2014
	Residential Inclining Block Rate	Section D4.6; discontinuation of this account effective January 1, 2015.
	Implementation of New Rate Structures	Section D4.6; discontinuation of this account effective January 1, 2015.
	Irrigation Rate Payer Group Consultation and Load Research	Section D4.6; discontinuation of this account effective January 1, 2015.
	Princeton Light and Power Deferred Pension Credit	Section D4.6; discontinuation of this account effective January 1, 2015.
	Princeton Light and Power Computer Software	Section D4.6; discontinuation of this account effective January 1, 2014.
	US GAAP Conversion Costs	Section D4.6; discontinuation of this account effective January 1, 2015.
	Joint Pole Use Audit, 2008	Section D4.6; discontinuation of this account effective January 1, 2014.
	Joint Pole Use Audit, 2013	Section D4.6; discontinuation of this account effective January 1, 2015.
	Mandatory Reliability Standards Implementation	Section D4.6; discontinuation of this account effective January 1, 2015.
	Revenue Protection	Section D4.6; discontinuation of this account effective January 1, 2015.

2.4 ACCOUNTING POLICIES

9. 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 FBC effective January 1, 2014;

(a) 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;

(b) Approval to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense, as explained in Section D3.1 of this Application;

(c) Approval to allocate Executive costs between FEI and FBC effective January 1, 2014 by way of applying the Massachusetts formula described in Section C4.17;.

(d) Continued approval of FBC's capitalized overhead rate of 20 percent as set out in Section D3.7;

(e) Continued approval of FBC's direct overhead charging methodology as set out in Section D3.8;

2.5 DEMAND SIDE MANAGEMENT (DSM) AS SET OUT IN APPENDIX H OF THE APPLICATION

In this Application, FBC is also seeking approvals to continue its DSM programs for the next five years. The approvals sought by FBC are as follows:

10. Acceptance pursuant to section 44.2(3) of the Act of the following DSM expenditure schedules as described in Appendix H2 of the Application: up to $3.0 million for 2014, $3.2 million for 2015, $3.2 million for 2016, $3.2 million for 2017, and $3.3 million for 2018;
11. Approval to change the amortization period of existing and future DSM expenditures from 10 years to 15 years, effective January 1, 2014; and
12. Approval to discontinue semi-annual reporting on its DSM Program and to submit annual reports as of December 31 in each year, effective January 1, 2014.

FBC's proposed regulatory process for this Application is set out in Section A6 below. FBC has provided a Table of Concordance with past directives in Appendix C1 and a Draft form of Order sought in Appendix I.

In the following three sections, FBC discusses its productivity and customer focus as well as its organizational performance and monitoring.

3. PRODUCTIVITY FOCUS

3.1 PRODUCTIVITY FOCUS

A priority for FBC and its employees is to improve productivity and realize efficiencies to more effectively manage rates for 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 and providing an appropriate level and quality of service.

During 2012 and 2013, employees were asked to consider embedded practices and rethink work while maintaining appropriate service levels. As a result, efficiencies were realized from streamlining processes, leveraging technology and optimizing opportunities for integration with FEI.

Streamlining and enhancement of processes contributed to increased productivity and provided increased service to customers. For example, FBC has eliminated the requirement for customers to provide a statutory right-of-way for simple underground secondary services that meet a certain set of criteria, improving service to customers while ensuring the efficient use of Company resources. FBC has continued to promote increased use of eBilling for customers who would prefer to receive their bill electronically, helping to reduce costs while improving customer service.

Productivity gains from leveraging technology include the increased use of desktop virtualization which has reduced support costs due to the ease and efficiency of supporting a virtual desktop from a central location. As well, FBC has introduced an on-line self-help Home Energy Calculator 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.

Integration with the gas utility 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 electric and gas businesses and providing employee growth and development opportunities. The integration of the electric and gas utilities is described in greater detail in the following section.

For further discussion and other productivity examples, refer to the O&M departmental review in Section C4.

3.2 SHARING OF GAS AND ELECTRIC SERVICES

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

In 2012, the electric and gas 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 FBC and the FortisBC Energy Utilities (FEU). 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 (excluding overhead charges)[8].

Integration driven opportunities in 2012 included 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 electric and gas 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 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.

The O&M forecasts reflect a sharing of labour resources between the different electric and gas departments. Instead of using a Shared Services cost allocation model similar to that approved for allocating shared services costs among the FEU, a timesheet allocation approach is being used which allocates costs based on actual and/or specific estimates of time. Given the evolving nature of integration efforts between the electric and gas businesses, this timesheet allocation approach continues to be the appropriate approach to allocate the majority of shared costs between the two organizations. Consistent with the existing allocation of Board of Directors' costs, FBC is seeking approval to allocate Executive costs on the basis of the Massachusetts Formula, which is explained further in Section D3.5.

FBC will evaluate the feasibility of introducing a Shared Services cost allocation approach during the PBR Period similar to that used among the FEU. 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

[8] 2012 – 2013 RRA Decision, Order G-110-12, page 48.

a representative approach to allocate costs and efficiencies between electric and gas, while minimizing the administrative efforts associated with the timesheet allocation approach.

3.3 PRODUCTIVITY FOCUS – 2013 AND ONWARD

FBC will continue to engage in efficiency review activities and to pursue productivity gains as it has during its two previous PBR plans and during 2012 and 2013, with the emphasis on managing costs.

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 electric and gas 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 somewhat slower given the highlighted challenges, and may require investments in IT systems or other initiatives.

In providing value for FBC's 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 any 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 an incentive to find efficiencies in its operations, 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. FBC 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 FBC's customer focus and initiatives throughout the PBR period to meet customers' expectations.

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 and concerns, while controlling costs and maintaining system reliability and safety. Recently, despite the fact that customer service has been maintained at a high level, FBC's customer satisfaction survey has reflected the effect of customers' perceptions of and reactions to the recently implemented two-tiered Residential Conservation Rate (RCR) and the proposed AMI Project.

As directed by the Commission, FBC applied for and the BCUC approved, by Order G-3-12, an inclining block rate – the RCR – as the default rate structure for the Company's residential customers, effective July 1, 2012.

The implementation of the RCR has occurred much as anticipated in the application and has been largely without issue from an implementation and administration perspective. It has however been met with customer concern and dissatisfaction from certain customer segments which has resulted in a number of complaints to both the Commission and Company. As a requirement of the RCR approval, FBC must file an evaluation report on the effectiveness of the rate, in particular with respect to its impact on conservation.

The Company believes that given the increased level of interest in the RCR, and the need for a better understanding of the impacts on customers and conservation, the report should be filed as soon as possible. FBC is committed to working with the Commission to generate such a report prior to the end of 2013. Among the items to be reviewed are the structure of the rate itself, including the consumption block threshold and the relative charges of the components of the RCR.

FBC is continuing its efforts to provide information about its AMI project to customers. The benefits of that project include not only lower customer rates, but non-financial benefits as well. More detailed electricity use information will be made available to customers through the FBC website as well as through optional, customer-owned, in-home displays helping customers to better understand their bills and manage their consumption. FBC will have more immediate notification of power outages to more effectively respond to unplanned outages and help ensure that all customers have their power restored in a timely manner. The need to access customer premises will be reduced, as will greenhouse gas emissions. It is the Company's belief that, post-deployment, the level of customer dissatisfaction with advanced meters will be mitigated.

In this application FBC also addresses customer rate increases. Consistently, customer surveys indicate that price ranks highly among customer concerns with regard to utility service. The Company's PBR proposal, which includes formulas for the determination of O&M and capital expenditures over the next five years, and the proposed rate stabilization mechanism, all serve to mitigate rate increases and to decrease rate uncertainty over the PBR term.

4.3 *CUSTOMER SERVICE INITIATIVES*

FBC provides virtually all customer service functions using internal staff located in the service territory. The Trail Contact Centre responds to a wide variety of customer queries by email, conventional mail and telephone in addition to managing collections activities. The billing function is located in Trail, and supports the current manual meter reading activities throughout the FBC service territory. The operations team handles customer requests for new service drops and extensions with staff located throughout the service territory.

The FBC customer service functions are mature, effective and meet the needs of customers. Nevertheless, FBC sees potential to improve customer value in the future by focusing on delivering improved service while controlling costs.

FBC will deliver on this goal in part by continuing to provide new lower-cost optional services to customers. One example is eBilling, which has been voluntarily adopted by nearly 19 percent of customers. These customers find this billing option better suits their needs than paper billing, while at the same time it is less costly for FBC and therefore all customers.

During the PBR Period, FBC intends to introduce new self-service options, which will similarly reduce costs if adopted by customers. FBC intends to provide customers with the ability to access their billing data and consumption information through web browsers and mobile devices. Following the deployment of AMI, consumption information will be available on an hourly basis, allowing customers to analyse their consumption more effectively than ever before; customers will be able to get the more detailed consumption information less than 24 hours after the energy has been used. This type of information will allow customers to respond more effectively to conservation rates such as the current Residential Conservation Rate (RCR).

Customers will also be able to customize their interactions with the Company with the availability of new notification services. These optional notification services are expected to include outage information, billing date reminders and energy efficiency updates. If the customer wishes, these notification preferences will be configured in a web browser or mobile device.

As always, FBC will continue to ensure that its employees are well trained to deliver on the expectations of customers by providing prompt, low-effort interactions through the medium they choose.

5. ORGANIZATIONAL PERFORMANCE AND MONITORING

5.1 *BALANCED SCORECARD*

FBC uses 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.

FBC's current Scorecard is comprised of four categories of measures, which are standardized between the electric and gas businesses. In total, six measures describe and guide the Company' overall performance in meeting the targets, which are set annually. The scorecard serves as a valuable communication tool used to describe in clear and objective terms success measures. The four categories of measures include Financial, Safety, Customer and Regulatory and are described below.

5.2 *FINANCIAL*

Net earnings for FBC 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 measured through the All Injury Frequency Rate (AIFR) which is the number of medical treatment injuries 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 and reinforce FBC's conviction 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 system reliability. Customer satisfaction as measured through an index score is designed to reflect feedback from residential and business customers on the reliability of power, billing and call centre services, field services, energy conservation, community involvement and public safety. The System Average Interruption Duration Index measures the cumulative time that a customer's power is interrupted, on average, during the year, reflecting overall the overall reliability of FBC's power system.

5.5 REGULATORY

Regulatory performance highlights the importance of achieving success on regulatory issues and agreements. 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.

5.6 SUMMARY OF BALANCED SCORECARD

FBC believes the Scorecard is an effective tool for improving organizational alignment and helping to focus the Company's' activities on key measures. The Scorecard, which is reviewed and updated annually by the Company, remains an essential tool to measure the Company's' performance on key success measures important to customers, employees, the regulator, and the shareholder.

6. PROPOSED REGULATORY PROCESS

FBC proposes that this Application can be addressed efficiently and effectively through a Negotiated Settlement Process (NSP). FBC has discussed the proposed process with its customary intervener groups, and understands that they are not opposed to an NSP. FBC's proposed regulatory timetable presented below seeks to acknowledge the workload required by the Commission and all parties and which will promote an efficient regulatory process. The Company will, if necessary, bring forward any material changes to the Application in an Evidentiary Update.

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[9]. FBC 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 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 Earnings Sharing Mechanism (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.

FBC 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.

[9] Appendix D7-1: J. Doucet and S. Littlechild "Negotiated Settlements and the National Energy Board in Canada" (2009) Energy Policy 37(11): 4633-4644.

The Commission, in its Decision in the FEI (then BC Gas Utility Ltd.) 2003 Revenue Requirements Application[10], endorsed the NSP process as being appropriate in the context of PBR, stating that the Commission: "has come to the view that multi-year PBR through negotiated settlement processes and periodic oral public hearings complement one another and provide the optimum overall regulation of the Utility."

On June 19, 2013, FBC and FEI held a joint workshop to review the PBR proposal, the elements of which are common to both utilities. The workshop materials are included in this Application as Appendix B9.

FBC's proposes the following regulatory timetable, which includes a further workshop on July 25, 2013 in Kelowna and procedural conference following one round of Information Requests (IRs). The procedural conference would determine the need for a second round of IRs and the remainder of the regulatory timetable

ACTION	DATE (2013)
PBR Workshop	June 19
Application Filed	July 5
Workshop	July 25
Commission Information Request No. 1 to FBC	August 7
Intervener Information Request No. 1 to FBC	August 14
FBC Response to Information Requests No. 1	September 13
Procedural Conference	September 25

FBC 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. FBC 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.

[10] Order G-7-03

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 FBC, a comparison to PBR in other jurisdictions, and a summary of all of the key PBR Plan elements. Section B also includes the Company's proposal for rate stabilization over the PBR Period;
- Section C sets out the Company's forecasts for the PBR Period as follows:
    - Section C1: Load forecast and resulting revenues at existing rates;
    - Section C2: Forecast power purchase expense;
    - Section C3: Forecast of other income;
    - Section C4: Historical and forecast O&M with supporting departmental summaries and drivers; and
    - Section C5: 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;
    - Section D4: Deferral Accounts; and
- Section E provides the financial schedules filed in support of the 2014 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 FBC's proposal for a Performance-Based Ratemaking plan for a five year period commencing in 2014 and provides other background information with respect to PBR. The material in this section, along with information contained in Appendices D1 through D9, provides FBC'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 applications and provide a review and comparison of PBR regimes in effect in other jurisdictions with the proposed PBR plan.

FBC has had two PBR plans in the past (1996-2004 and 2007-2011) and both were successful, further aligning the interests of customers and the Company. FEI, in addition, has also set rates according to PBR plans between 1998-2001 and 2004-2009. In FEI's 2012-2013 RRA the Commission examined the results of FEI's 2004-2009 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."*[11]

The proposed 2014 PBR Plan builds on FBC's successful 2007 PBR Plan. The 2014 Plan focuses the performance incentives on the two main areas of controllable costs, operating and maintenance (O&M) expenses and capital expenditures, the latter being an enhancement to the 2007 PBR Plan. The formulas to be applied to O&M and capital expenditures over the PBR term have the same structure as the O&M formula in the 2007 PBR Plan, employing the same cost drivers, an inflation factor and a productivity improvement factor (PIF); however, some refinements to the formula parameters are proposed.

The success of FBC's 2007 PBR Plan provides a strong basis for going forward with a similar model for the proposed PBR. The model approved for use by FBC between 2007 and 2011

[11] Commission Order G-44-12, Reasons for Decision, page 22

provided a flexible framework of incentives that allowed FBC 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 2007 to 2011, the Commission should have confidence that the incentive framework in the proposed PBR Plan will lead to a similar response from FBC during this plan.

FBC's PBR experts, B&V, has studied the available PBR methodologies and provided their its recommendations on FBC's proposed PBR Plan model in Appendix D1 *Comparison of Recent Performance Based Regulation for Distribution Utilities in Canada* (the PBR Report). B&V concludes that there is no one "right" PBR model, and that the framework adopted for FBC should be in keeping with FBC'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 FBC. FBC's proposed PBR incorporates a more aggressive "stretch" productivity factor than is suggested by B&V's research on Total Factor Productivity (TFP) for other North American utilities, which is included as Appendix D2 *Estimating Total Factor Productivity - Theory and Practice for Electric Utilities* (referred to as the TFP Report or TFP Study) FBC's model produces similar rate increases over the five year period to those calculated using an indicative cost of service approach[12].

FBC believes that the proposed PBR Plan is an appropriate model that will encourage FBC 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, which has provided input in the preparation of both the PBR Plan and this chapter of the Application,[13] endorses the overall proposed PBR Plan as being reasonable in the circumstances of FBC, with the exception that it regards the "stretch" productivity factor as being more aggressive than is warranted. B&V regards the appropriate productivity factor as being approximately zero, based on the TFP study it conducted and the specific elements of the proposed PBR Plan. In other words, FBC's proposal is more favourable to customers than B&V would recommend. FBC is nonetheless willing to stretch and attempt to achieve the productivity factor as proposed as part of an overall package.

The section is organized as follows:

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

[12] FBC's reference to an "indicative" cost of service approach means the revenue requirement that would result not from using the O&M and capital inputs derived from the PBR formula method, but using the O&M and capital expenditures identified in Sections C4 and C5, which reflect the future cost pressures that FBC is currently aware of, and which would be the starting point for "bottom up" O&M budgets in a cost of service application, and the capital expenditures that would form the basis for its capital expenditure plan in the absence of a PBR proposal.

[13] 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. FBC 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 – FBC Experience with PBR – an historical review of FBC's prior PBR plans;
- Section B5 – Jurisdictional Comparison – a review of the most recent PBR plans employed in Canada;
- Section B6 – FBC 2014 Proposed PBR – a full description of the proposed PBR for 2014-2018;
- Section B7 –2014-2018 Rate Forecasts – a comparison of customer rates under the proposed PBR with rates under an indicative cost of service regulatory approach; and
- Section B8 – Conclusion.

2. THE OBJECTIVES OF PBR

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[14] 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. 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, FBC'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

[14] 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 FBC's proposed PBR Plan that appropriately address these challenges.

B&V observes 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 address this issue, for instance, in its TFP Report (refer to Appendix D2, page 8), 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 observes that, for this reason, PBR plans typically include provisions relating to service quality. FBC's 1996 and 2007 PBR Plans, for instance, included a variety of non-financial performance indicators on which FBC was required to report in the Annual Reviews. Service Quality Indicators (SQIs) are proposed in the current FBC proposal as well.

B&V identifies 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 observes 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. These are sometimes referred to as "capital trackers", a concept akin to excluding CPCN projects from the operation of the PBR formula.

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.

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:

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

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:

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

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. FBC'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 FBC's more challenging and aggressive proposal of 0.5 percent.

4. FBC EXPERIENCE WITH PBR

The Commission letter dated April 18, 2013, titled "Productivity Improvements in a Performance Based Rate Setting Environment", requested that FBC's examination of PBR methodologies include discussion of the most recent PBR plans employed by FBC. FBC has had two PBR plans in the past (1996-2004 and 2007-2011), both of which were successful. FBC's proposed 2014 PBR Plan builds on that success, incorporating a number of similar elements, with adjustments where appropriate. This section outlines FBC's past PBR plans. Further discussion regarding FBC's most recent PBR Plan is included in B&V's PBR Report.

4.1 *FBC PRE-2007 PBR EXPERIENCE*

In 1996, FortisBC (then West Kootenay Power), as part of its 1996 Revenue Requirements Application, received Commission approval to enter into a PBR plan to replace cost of service regulation. The plan consisted of 'targeted' cost categories with cost drivers, base costs, escalators, productivity improvement factors (PIFs) and a sharing mechanism. In addition to cost categories, performance standards including customer satisfaction and system reliability were included as part of the PBR plan, and were subject to periodic review to confirm that service quality was being maintained throughout the term.

The PBR plan was originally approved for 1996-1998, but was subsequently 'rolled-over' and extended to 2003. In 2004, FBC requested that the 2003 agreement be maintained in light of the change in ownership of the Company, which was agreed to by the BCUC. Subsequent agreements modified some of the incentive mechanisms included as part of the original PBR plan. The modifications included the introduction of a power purchase variance mechanism and market incentive mechanism, as well as the exclusion of capitalized overhead from the sharing mechanism.

4.2 *FBC 2007 PBR EXPERIENCE*

FBC's subsequent PBR plan commenced in 2007 pursuant to an approved Negotiated Settlement Agreement and remained in effect (after an approved three-year extension) until 2011. The 2007 Plan was based on the previous PBR plan in key aspects, and included the continued use of cost and growth escalators and PIFs. A key difference in the 2007 PBR plan was the exclusion of the determination of capital expenditures as part of the PBR plan. Instead, capital expenditures were to be approved as part of a separate annual filing or by way of filing CPCN applications for major projects. As well, an earnings sharing mechanism replaced the previously-existing line-by-line review used to determine the level of any incentive sharing between the Company and its customers. The use of an ROE sharing mechanism provided the Company a greater incentive and flexibility to pursue efficiencies and savings on a Company-wide basis as opposed to a line-by-line basis. Additional modifications included changes to the performance indicators to improve the measurement of customers' satisfaction with both the quality and reliability of service as well as the convenience of customers' routine interactions with FBC. The efficiency of annual rate-setting processes under PBR was greater, and the costs were significantly lower than would have been the case under cost-of-service rate setting.

4.2.1 Term

FBC proposed a three year term for the 2007 PBR term, from 2007-2009. The proposed three-year term from 2007-2009 was rejected, but the Commission-approved negotiated settlement agreement established a two-year term from 2007–2008 with an option to extend for a third year 2009. In 2008, the term was extended for three years, ending in 2011.

4.2.2 O&M Expenses

The 2006 O&M, excluding Pension, Post Retirement Benefits, and the Trail Office lease costs, was determined on an incremental basis from the 2005 O&M which had been reviewed by way of an oral hearing. This 2006 O&M was used as the base year cost, and then escalated by inflation and a customer growth factor and decreased by a productivity improvement factor to determine the gross O&M expense for a given year. Customer growth was expressed as the change in the average number of customers from one year to the next. Capitalized Overhead was set at 20 percent of gross O&M for the term of the PBR.

4.2.3 Capital Expenditures

As discussed previously, capital expenditures were not included in the 2007 PBR plan, and were instead to be approved as part of a separate annual filing or by way of applications for CPCNs for major projects.

4.2.4 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;
- Royal Bank Financial Group (2007 – 2009)[15]; and
- Toronto-Dominion Bank.

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

4.2.5 Productivity Factor

The 2006 Negotiated Settlement Agreement (NSA) established PIFs of 2 percent for 2007, 2 percent for 2008, and 3 percent for 2009 (if the term of the PBR was extended). For the period 2009 – 2011, the Parties to the 2009 NSA agreed that some linking of the productivity factor to BC CPI would be beneficial. As such, the 2009 NSA established PIFs of 1.5 percent for 2010

[15] The Royal Bank discontinued forecasts of BC CPI after 2009

and 2011 when BC CPI is less than 3 percent, with the PIF increased to offset any increase in BC CPI above 3 percent.

4.2.6 Customer Growth

As part of the Annual Reviews during the term of the PBR plan, 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.

4.2.7 Earnings Sharing Mechanism

The variance between the allowed and actual earnings (after being adjusted for certain revenue and cost variances), up to a 200 basis point collar around the approved ROE, were to be shared equally between customers and shareholders. The 200 basis point collar was not exceeded during the term of the PBR. Over the 2007 - 2011 term of the PBR, customers and shareholders each received a benefit of $7.6 million, indicating that the PBR successfully reduced costs and resulted in material savings, including an avoided rate increase of approximately 2.7 percent.

4.2.8 Performance Standards

FBC established a number of non-financial performance standards to provide an overall assessment of the Company's performance for the purpose of determining its eligibility for any incentive earned under the PBR sharing mechanism. The performance standards and associated targets agreed to as part of the 2006 and 2009 NSAs were intended to ensure 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. The test for inadequate performance and, hence, consideration for disqualifying the Company from receiving a financial incentive was:

> *If the Company earned a financial incentive, did it do so as a direct result of allowing or causing its performance to deteriorate in a material way.*[16]

As part of the Annual Review process, the performance metrics were reviewed in detail with regard to actual results achieved and the circumstances under which the results were achieved with reasons provided for variances from the target. Under this framework, failure to meet one (or more) performance standard(s) did not necessarily constitute unacceptable performance.

4.2.9 Annual Review

At its Annual Reviews, FBC presented its actual results from the previous year, projections for the current year and updated forecasts for the coming year. The Annual Reviews provided parties with information as to the Company's past performance and kept them apprised to any potential challenges facing the Company in the future. The Company's performance metrics were also reviewed as part of the Annual Review process.

[16] Order G-58-06, Appendix 1

4.2.10 Results

The PBR plan allowed significant savings and benefits to be achieved for both customers and the Company. These benefits were achieved through the productivity improvement factor and through the achieved O&M savings.

Productivity Improvement Factor

In total the Company achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors over the 2007-2011 period, which represents a material benefit to customers (over $5 million of annual savings were imbedded into O&M by 2011) even before any incremental earnings above the approved ROE could be achieved and shared. The lasting benefit to customers from these efficiencies was that FBC had a lower O&M as the base level for the cost of service period that followed with the 2012-2013 RRA.

In addition, the productivity improvements achieved during the 2007-2011 PBR period were accomplished without degradation in the quality of service provided to customers. As well, performance metrics were generally maintained or improved.

O&M Savings

During the PBR period, FBC found efficiencies to not only meet the10.4 percent productivity improvement, but also found approximately $4 million in additional O&M savings which were effectively shared equally with customers through the ROE sharing mechanism. After factoring out the transfer of certain expenditures from capital to O&M expense as directed by Order G-195-10 concerning the Company's 2011 Capital Expenditure Plan, as well as exclusion of those items considered under the PBR mechanism as extraordinary O&M expense or Z-factors, the O&M expense per customer, on a real basis, declined over the 2007-2011 PBR period. O&M savings achieved during the PBR Period benefit customers in two ways:

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

Clearly, PBR was beneficial to customers, with FBC successfully managing its O&M expenditures during the PBR term to minimize the impact to customer rates while still ensuring acceptable levels of service quality were maintained.

5. JURISDICTIONAL COMPARISON

The Commission letter dated April 18, 2013 requested that FBC's evaluation include the most recent PBR plans employed by FortisBC Inc. and the FEU, and PBR methodologies approved in other jurisdictions in Canada. B&V was retained to assist FBC 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, FBC summarizes the elements of PBR plans employed in other Canadian jurisdictions. B&V's report, which is included in Appendix D1, contains further analysis. FBC'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. FBC 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 that 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)[17]	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[18]	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

17 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. The OEB expert TFP report recommends modifications to the current TFP study and to the stretch factors.

18 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)[17]	Gaz Metro (2007-2012)
					percent of rate base 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				

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 and FBC's 2009 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.

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. FBC 2014 PROPOSED PBR

6.1 *PBR PRINCIPLES*

In developing the PBR Plan, FBC 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 FBC 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 electrical 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, FBC outlines the key elements of the proposed PBR Plan. FBC's proposal builds on the 2007 PBR Plan, with some adjustments, including a formula-driven level of capital expenditures, to enhance a customer focus and further promote FBC's productivity improvement culture. The proposed PBR shares common elements with plans in other jurisdictions, but FBC has preferred continuity with the past experience in circumstances where there are no obvious benefits, and possible 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 provide its expert assessment of individual elements of FBC'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 FBC, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regards 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, FBC's proposal is more favourable to customers than B&V would recommend. FBC is nonetheless willing to incorporate such a stretch factor and to attempt to achieve the productivity factor proposed as part of an overall package..

Table B6-1 summarizes the items of FBC'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 to 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 reforecast annually.
Controllable Expenses - Capital	The same formula as O&M will be used. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%.
Flow Through Expenses and Revenues	Revenues and non-controllable costs, after being re forecast each year, are flowed through in rates 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 Plan includes an equal earnings sharing between Customers and the Shareholder for returns above or below the approved return on equity.
Efficiency Carry-Over Mechanism	An 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	9 SQIs (5 SQIs with a target benchmark and 4 informational measures) are proposed that deal with emergency response, customer service, employee safety and system reliability.
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 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 Plan.

6.2.1 Term

FBC 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 the same as FBC's 2007 Plan, in which an approved three-year extension was added to the initial two-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, a five-year period provides an adequate amount of time for FBC 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. In addition, the proposed Efficiency Carry-over Mechanism (discussed below) will provide incentive for FBC 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, FBC 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 five years is a reasonable plan term for FBC's PBR Plan, having regard to the other elements of FBC'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 FBC is proposing a change from the 2007 PBR Plan. FBC'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. FBC proposes to use instead a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to BC Average Weekly Earnings (BC-AWE) and non-labour indexed to BC-CPI[19]. FBC 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. With regard to the 2014 PBR proposal of FEI, which mirrors that of FBC in most respects, 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, FBC 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

[19] The sources used to forecast BC-CPI for the PBR Period are shown in Table B6-2.

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[20]. FBC 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, FBC believes the weighting should reflect the Company's proportion of labour and non-labour costs.

FBC forecasts that over the PBR term an average of 55 percent of costs are labour-related while 45 percent of costs are non-labour related. For that reason, FBC 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 FBC's previous PBRs, FBC has calculated an average BC-CPI forecast from an average of several sources. The forecast BC-CPI is determined as shown in the following table[21]:

Table B6-2: BC-CPI Forecasts for the PBR Period[22]

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%**

[20] Appendix D8 AUC Decision 2012-237 Rate Regulation Incentive Distribution Performance Based Regulation
[21] Backup for the referenced sources of BC-CPI and BC AWE is found in Appendix E1. Not all referenced sources for BC-CPI 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.
[22] Refer to Appendix E1 for source information.

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:

Table B6-3: BC AWE Forecasts for the PBR Period[23]

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 forecast to be 1.83 percent and 2.70 percent respectively. As such, FBC 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, FBC 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. FBC 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. FBC proposes a fixed X-Factor of 0.5 percent (inclusive of any stretch factor) for its 2014 PBR Plan.

B&V was commissioned to perform a detailed analysis of industry-wide TFP growth and provide a survey of measured TFPs among electric utilities in other North American jurisdictions. FBC has also considered the business conditions that it expects to face during the PBR term as well as the potential for higher than forecast inflation impacts on its capital expenditure requirements, and the O&M inputs discussed in Section C4 to derive a reasonable and fair X-Factor. FBC has already embedded a great deal of efficiency into its operations – 10.4 percent cumulatively over the term of its last PBR Plan in 2007 - 2011. 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 FBC's proposed 0.5 percent X-Factor,

[23] Refer to Appendix E1 for source information.

and were prepared with the assistance of B&V, reflecting B&V's views except where attributed to FBC.

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 electric utilities are mainly caused by a combination of customers, density, the age of assets and peak load 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 an electric utility 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)[24] 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[25] (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

[24] Appendix D7-2, Crew 1996 Incentive Regulation in the UK
[25] Appendix D7-3, Beesley, M.E. and Littlechild, S.C., The Regulation of Privatized Monopolies in the United Kingdom, Rand Journal of Economics, Autumn 1989.

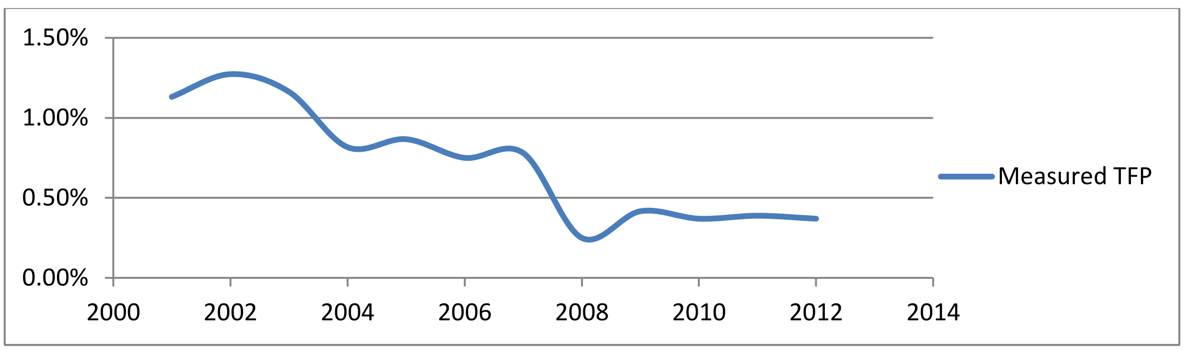
affect the costs, revenues and risks of the regulated company". These parameters include items such as the PBR term, cost items subject to flow-through in customers' rates, the implementation of other sharing models such as earnings sharing mechanisms, the use of historical or expected performance as 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, the services of B&V were retained 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 percent, 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 percent. 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 FBC'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 four different output measures and the TFP results range between -4.0 to -6.2 percent. 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 72 US-based electric utilities. U.S. data has been used in other Canadian jurisdictions as well, and is appropriate because of common systems, technologies, and operating methods. For instance, the North American Electric Reliability Corporation includes electric 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 four different output measures based on the critical variables of customers served and system capacity, and two density-weighted composite factors using 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 production 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 electric 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

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

B&V and FBC are in agreement that B&V's TFP Report produces a more negative TFP number than would be applicable to FBC 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 production 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 FBC'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 FBC'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 FBC'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 forecast rate changes under the indicative cost of service model. As FBC explains in Section B8 of this Application, the rates arising from PBR formulas (the combination of proposed 0.5 percent X-Factor and the proposed composite inflator) will lead to rates that are virtually the same as the rates under the indicative cost of service model. This indicates that the proposed X-Factor is a reasonable estimate of expected productivity, which will ensure stability of O&M expense over the PBR period and challenge the Company to meet future cost pressures within the amounts allowed under the PBR Plan. FBC 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, FBC'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, FBC considers that a 0.5 percent X-Factor is an appropriate and reasoned value in the context of FBC 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 FBC 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 FBC'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 FBC Rates

The 2014 PBR Plan will determine customers' rates over the 2014 – 2018 period reflecting the costs incurred to build, maintain, finance and operate the infrastructure necessary to deliver electricity and provide service to customers.

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, rates for the following year will be determined. Section B6.8 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 FBC 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) to determine the amount of expenditures from 2014 to 2018 that will be included in rates. FBC 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 B6.4.

6.2.4 O&M under PBR

O&M expenses are essential to operate the system in a safe and efficient manner. In 2013, O&M expenditures are forecast to be $0.45 million lower than approved, savings that FBC has incorporated into its base level of O&M for the term of the proposed PBR Plan.
For the PBR Period, detailed O&M forecasts will not be used to set 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.

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 through an oral public hearing, FBC has used the 2013 Approved O&M[26] as the starting point for the O&M formula. A number of adjustments are then made to this figure to arrive at the "2013 Base". These adjustments are of three types:

- An adjustment of $0.45 million to recognize the sustainable savings that were realized in 2013 that will be carried forward to future years;
- Adjustments to include actual incurred 2013 "non-controllable" O&M that is held in deferral accounts in 2013; and
- Other O&M expenses and reductions necessary to provide cost-effective service to customers.

[26] Order G-110-12 regarding FBC's 2012 and 2013 Revenue Requirements, plus the O&M impact of the acquisition of the City of Kelowna utility assets, approved by Order C-4-13.

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. This follows the approach of FBC's 2006 Revenue Requirements, which established an O&M Base for the PBR mechanism, using incremental O&M adjustments to the previous year's approved O&M which had been determined by way of a full Cost of Service rate application and oral hearing.

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

Table B6-4: 2013 Base O&M

		($ thousands)	
1	**2013 Decision**		**57,621**
2			
3	Net Sustainable Savings		(452)
4			
5	2013 Adjustments		
6	Mandatory Reliability Standards	900	
7	Provincial Sales Tax	180	
8	Pension/OPEB (O&M Portion)	2,158	3,238
9			
10	Incremental O&M		
11	Trail Office Lease	(909)	
12	Generation Maintenance	350	(559)
13			
14	**2013 Base O&M**		**59,848**

Net Sustainable Savings:

The total savings against the approved O&M that are being embedded in the 2013 Base O&M for the future benefit of customers is $0.45 million[27]. This represents a 0.8 percent embedded savings from the 2013 approved level of O&M. O&M is further discussed in Section C4.

2013 Adjustments:

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

[27] Calculated against O&M approved by Orders G-110-*12 and C-4-13.

1. A $900 thousand increase in O&M expense related to the BC Mandatory Reliability Standards[28]
2. $135 thousand in the deferral account related to the reinstatement of PST for 9 months of 2013 (equivalent to $180 thousand for the full year)[29]; and
3. A total of $2.2 million to the Pension and OPEB (Other Post Employment Benefits) Variance deferral account.

Incremental O&M:

4. A reduction of $909 thousand in lease payments for the Trail Office, which will be purchased by FBC in 2013 as approved by way of Order G-110-12; and
5. An increase of $350 thousand for the recurring maintenance of FBC's generating units, as explained in Section C4.4.

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 the O&M related to implementation of the AMI Project. The pensions and OPEBs were excluded from the formula in the 2007 PBR and considered "flow through" items due to their recognized uncontrollable nature. FBC is also requesting flow-through treatment and exclusion from the PBR formula for insurance expense[30], which is also uncontrollable in nature, and consistent with the treatment previously accorded to FEI and proposed in the current FEI application. AMI-related expenses and reductions are excluded from the formula as the expenditure/savings profile is highly variable during the implementation period.

As in the 2007 Plan, the PBR formula FBC proposes to apply to the O&M is tied to the average number of customers. FBC 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:

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

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 forecast number of average customers, including its year to year percent change;

[28] Order G-23-13.
[29] See Section 2.3.1.
[30] See Section D4.3.6.

3. The composite I-Factor values; and
4. The Productivity X-Factor.

B&V considers 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 capacity component 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 as 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 plans revenue adjustment.

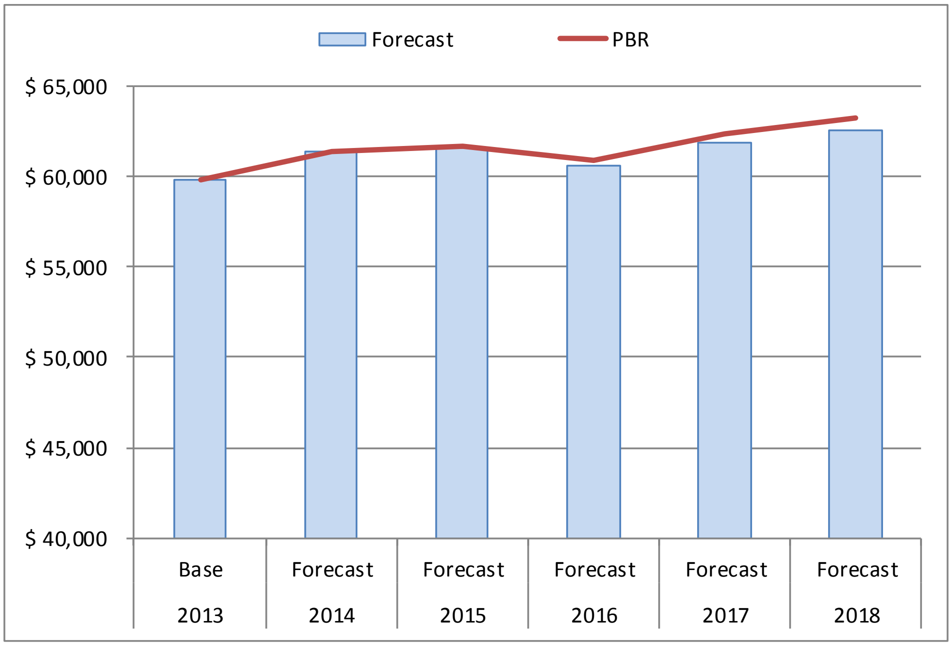
The O&M allowed under the PBR Plan is included in Table B6-5. As indicated above, the O&M allowed under PBR will be recalculated yearly in the PBR Annual Review, based on updated forecasts of customers composite inflation rates, and those items tracked outside of the formula, for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

Table B6-5: Forecast O&M Formula Results

Line No.	Particulars	2013 Base	2014 Formula	2015 Formula	2016 Formula	2017 Formula	2018 Formula
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**2013 Base O&M ($000)**	$ 59,848					
2	Less O&M Tracked Outside of Formula						
3	Pension/OPEB (O&M portion)	(6,222)					
4	Insurance	(1,588)					
5	Advanced Metering Infrastructure Project	-					
6		52,037	-				
7							
8	Average Number of Customers	128,796	129,770	130,922	132,142	133,385	134,687
9	% Change in Customers		0.76%	0.89%	0.93%	0.94%	0.98%
10							
11	Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
12							
13	Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
14							
15	I-X Mechanism (1+I-X) (Line 11 - Line 12)		101.81%	101.92%	101.84%	101.86%	101.80%
16							
17	Net Inflation Factor ((1 + Line 9) * Line 15)		102.58%	102.82%	102.79%	102.82%	102.79%
18							
19	**Formulaic O&M (Line 17 * Prior Year)**		53,380	54,888	56,419	58,009	59,629
20	Add: O&M Tracked Outside of Formula						
21	Pension/OPEB (O&M portion)	6,222	5,904	5,494	5,084	4,738	4,455
22	Insurance	1,588	1,734	1,801	1,868	2,000	2,012
23	Advanced Metering Infrastructure Project	-	368	(439)	(2,411)	(2,369)	(2,794)
24							
25	**Total O&M Under PBR**	59,848	**61,386**	**61,744**	**60,960**	**62,378**	**63,302**

Based on the inputs from Table B6-5 above and O&M forecasts provided in Section C4, Figure B6-2 below illustrates the comparison between the five year O&M forecasts, and the O&M calculated under the PBR Plan.

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



Forecast	$ 59,848	$ 61,375	$ 61,612	$ 60,608	$ 61,889	$ 62,634
PBR	$ 59,848	$ 61,386	$ 61,744	$ 60,960	$ 62,378	$ 63,302

As figure B-6-2 indicates, the O&M expense allowed under the PBR formula closely aligns with the forecast O&M throughout the PBR term, particularly in the early years of the PBR period. Considering the material efficiencies of 10.4 percent embedded in FBC's O&M expense by way of productivity improvement factors during its last PBR period from 2007 to 2011, and in particular the extent to which the proposed X factor exceeds the measured industry productivity levels, FBC believes this level of O&M expenditure allowed under PBR provides a strong incentive to continue to find efficiencies for O&M spending.

6.2.5 Capital Expenditures Under PBR

The formula–based capital expenditure[31] portion of the PBR Plan pertains to the main component of rate base over which the Company and its employees have the greatest degree of 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, leaving non-controllable rate base components for the annual forecasting process.

[31] In this Application FBC presents its capital expenditures before capitalized overheads, direct overheads, and AFUDC. From a project management perspective, "unloaded" capital expenditures are those over which the Company has most direct control, and are therefore most appropriate to be determined by formula. The capitalized overheads, direct overheads, and AFUDC are included in Additions to Plant in Service (see Section E, Table 1-A-1).

Capital expenditures include both regular capital expenditures and major projects (generally those approved by way of CPCN applications). Departing from its previous practice in filing revenue requirements applications, FBC has not included expenditures associated with future CPCN applications in this filing. This practice ensures that only approved capital expenditures will be reflected in customer rates. The only exception in this application is the inclusion of the revenue requirements impact of FBC's Advanced Metering Infrastructure Project, for which Commission approval is expected shortly. FBC will address any material revenue requirements impacts of a Commission decision, if necessary, by way of an evidentiary update.

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 existing criteria for determining the need for a CPCN application, which are referenced in Section C5.7. Major capital project 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."* (p.39)

FBC has included in its PBR formula the following three categories of regular capital expenditures – growth, sustainment and other capital. A description of the types of capital included in each of these categories is included in Section C5.

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 the formula-based capital expenditures will be recalculated yearly in the PBR Annual Review, based on updated forecasts of customers, composite inflation rates, and those items tracked outside of the formula, for the upcoming year.

6.2.5.1 2013 Base Capital

FBC 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. Adjustment for non-recurring major projects, as detailed in Table C5-2; and
2. Adjustments to include 2013 actual "non-controllable" items equivalent to those included in the Base O&M calculation

These adjustments determine the starting point or base for capital expenditures in the upcoming PBR period.

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

Table B6-6: 2013 Base Capital

	Approved	less Major Projects	Applicable to Formula	PST	Pension	2013 Base
1 Sustainment Capital	28,215	(9,021)	19,194	151	702	20,047
2 Growth Capital	22,625	(2,865)	19,760	155	723	20,638
3 Other Capital	51,130	(42,996)	8,134	64	298	8,495
4 Total Capital Expenditures	**101,970**	**(54,882)**	**47,088**	**369**	**1,723**	**49,180**

FBC has not included an adjustment in the 2013 Base calculation for the former City of Kelowna utility assets acquired in 2013, as it intends to absorb the future capital expenditures related to those assets within the capital funding under the formula.

Consistent with the calculation of O&M set out in the previous section, the portion of Pension and OPEB applicable to labour inputs to capital expenditures is also tracked outside of the formula.

6.2.5.2 2014 -2018 Capital

The PBR formula that FBC proposes to apply to capital expenditures is tied to the average number of customers. B&V note that in actual fact, growth, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no straightforward 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 extensions of the system to serve customers adds new capacity to the system.
The following formula illustrates the formula applied to capital expenditures:

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

Where: *C=Capital Expenditures subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The inputs used for calculating capital expenditures under the PBR Plan include:

1. The total 2013 Base Capital;
2. The 2013 base and forecast number of average customers, including its year to year percent change;
3. The composite I-Factor values; and
4. The Productivity X-Factor.

The capital expenditures allowed under the PBR Plan is included below in Table B6-7. As for O&M Expense, the capital expenditures allowed under PBR will be recalculated yearly in the PBR Annual Review, based on updated forecasts of customers composite inflation rates, and those items tracked outside of the formula, for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

The non-recurring capital projects during the PBR period are:

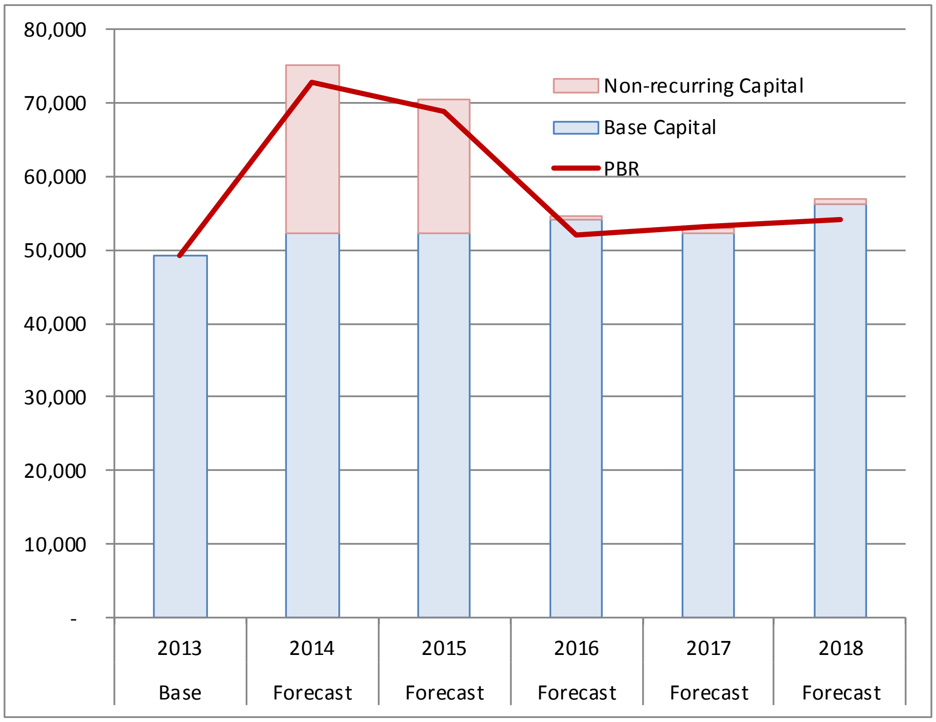
1. The substation portion of the PCB Environmental Compliance program, which will be completed during 2014, described in Section C5.4.3.1; and
2. The Advanced Metering Infrastructure project and the associated Information Systems expenditures, described in Section C5.6.9.

Table B6-7: PBR Capital Formula Inputs and 5-Year Forecasts

Line No.	Particulars	2013 Base	2014 Formula	2015 Formula	2016 Formula	2017 Formula	2018 Formula
		(1)	(2)	(3)	(4)	(5)	(6)
1	**2013 Base Capital ($000)**	$ 49,180					
2	Less Capital Tracked Outside of Formula						
3	Pension/OPEB (Capital portion)	(6,741)					
4		42,439					
5							
6	Average Number of Customers	128,796	129,770	130,922	132,142	133,385	134,687
7	% Change in Customers		0.76%	0.89%	0.93%	0.94%	0.98%
8							
9	Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
10							
11	Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
12							
13	I-X Mechanism (1+I-X)		101.81%	101.92%	101.84%	101.86%	101.80%
14							
15	Net Inflation Factor ((1 + Line 7) * Line 13)		102.58%	102.82%	102.79%	102.82%	102.79%
16							
15	**Formulaic Capital (Line 15 * Prior Year)**		43,534	44,764	46,012	47,309	48,630
16	Add: Capital Tracked Outside of Formula						
17	Pension/OPEB (Capital portion)	6,741	6,396	5,952	5,508	5,133	4,826
18	PCB Compliance - Substations		6,062				
19	Advanced Metering Infrastructure Project		16,765	18,233	583	741	604
20							
21	**Total Capital Under PBR**		**72,758**	**68,950**	**52,103**	**53,183**	**54,060**

Based on the inputs from Table B6-7 above, Figure B6-3 below illustrates the comparison between the five year capital forecasts as described in Section C5 and the Capital Expenditures allowed as calculated under PBR.

Figure B6-3: Comparison of PBR Capital vs. Capital Forecast



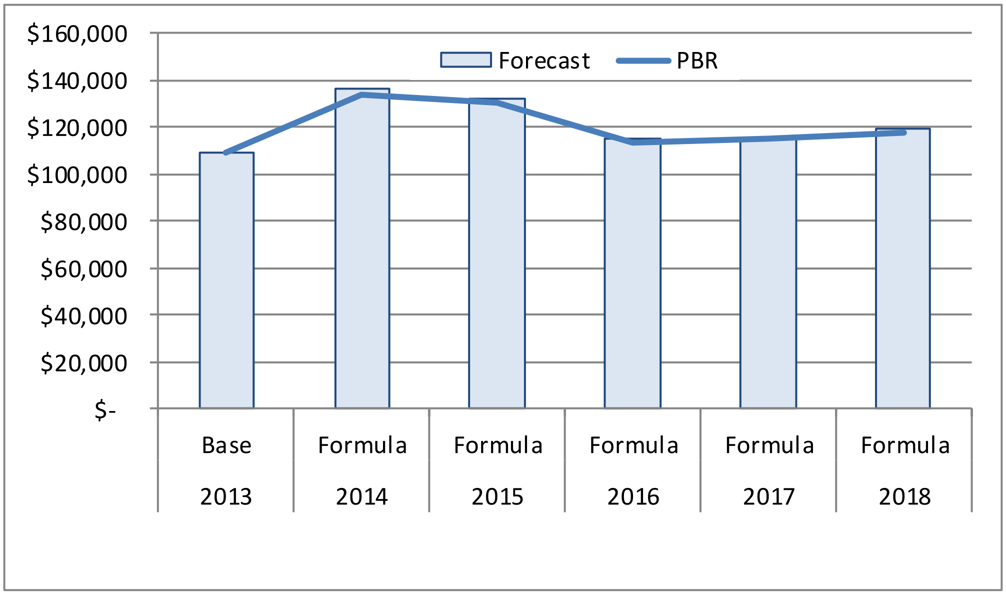
	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Forecast	$ 49,180	$ 75,176	$ 70,435	$ 54,681	$ 53,028	$ 56,960
PBR	$ 49,180	$ 72,758	$ 68,950	$ 52,103	$ 53,183	$ 54,060

Total allowed expenditures under PBR for the period 2014 – 2018 ($301.1 million) are lower than the five year capital forecast ($310.3 million), by 3.1 percent. FBC believes that the proposed PBR Plan provides a strong incentive for FBC to find efficiencies for all expenditure throughout the PBR term, particularly as capital expenditures for the City of Kelowna's utility assets will be absorbed in the PBR formula calculation.

6.2.5.3 Total O&M and Capital Under PBR

When the O&M and capital allowed under the PBR formula are examined together, the total is lower than what has been forecast by FBC in every year of the PBR term, with the exception of 2017. In other words, customers will benefit under the proposed PBR Plan since the resulting costs for customers under PBR are less than what FBC is forecasting they would likely be if rates were set under an indicative Cost of Service model using the O&M and capital forecast in Sections C4 and C5 (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 O&M and capital 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



Forecast	$109,028	$136,551	$132,047	$115,289	$114,917	$ 119,594
PBR	$109,028	$134,144	$130,694	$113,063	$115,561	$ 117,361

As Figure B6-4 indicates, total allowed expenditures under the PBR formula fall below the forecast over the PBR term. FBC believes that the proposed PBR Plan provides a strong incentive for FBC 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, FBC 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.

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. FBC 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 FBC 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 proposed 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. A deferral account will record variances in long-term and short-term interest costs in accordance with the method approved by the Commission for FEI. 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. FBC will flow through any Commission-approved changes to the ROE and capital structure in the Annual Review process each year. As noted in Section A.2, FBC will flow through the impact of any changes to its capital structure arising from a decision in the Stage 2 GCOC proceeding during 2014.

Taxes

FBC proposes that variances in property tax expenses, income tax rates, and other tax items be 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 FBC's insurance provider. Projected year-end deferral account balances will also be provided at the Annual Reviews.

Power Purchase Expense

Variances in Power Purchase Expense from amounts included in rates arise from factors outside of FBC's control, including load variances due to variances in customer growth, usage, or weather; unit price variances from forecast, including market prices compared to forecast and regulated price changes (BC Hydro rates and other contracts whose prices are tied to BC Hydro rates) not known at the time of application; and factors related to the operation of the Canal Plant Agreement governing FBC's generation plants, which affect the Company's usage or timing of entitlements. FBC also flows through the benefits of its ability to displace BC Hydro purchases with lower-cost market purchases. All such variances are deferred and returned or recovered in future rates as approved by Order G-110-12.
Power Purchase Expense will be forecast each year at the Annual Review and included in the determination of the revenue requirement and rates for the forecast year.

Revenues

Revenues include amounts received from customers for the sale electricity, and various other sources of revenue which are detailed in Sections C1 and C3. The majority of variances in sales revenue are attributable to weather-related load variances, customer usage rate variances and customer count load variances which are not under the control of FBC. FBC's Revenue Variance Deferral Account was approved by Order G-110-12.

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.

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. 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). Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include plant additions consistent with the formula-based capital expenditures. 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 Plant in Service (from Capital Expenditures)

Section B6.2.5 explains that the use of formula-based calculations will be limited to the regular capital expenditures. Larger projects which will be the subject of CPCN applications in addition to any other large projects that the Company may ask for approval as part of the Annual Review 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, including deferral account balances, cannot be reliably reduced to a formula, therefore FBC 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 exogenous factors or Z-Factors. Consistent with the 2007 PBR Plan, FBC 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 FBC 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, page 7).

6.4 *EARNINGS SHARING MECHANISM*

FBC is proposing to include an ESM as a component of the PBR Plan. The rationale for ESMs generally, and FBC's proposal to adopt an ESM design based on the 2007 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 militate 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 FBC'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

FBC is proposing to adopt an ESM based on the 2007 PBR Plan.

[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 D7-4 Lyon, Thomas P, 1996. "A Model of Sliding-Scale Regulation," Journal of Regulatory Economics, Springer, vol. 9(3), pages 227-247, May.

FBC's 2007 PBR Plan included an earnings sharing mechanism on an equal basis between customers and the Company for earnings above and below the allowed ROE as established each year by the Commission, with a provision for deferral and review of any amounts greater than 200 basis points. FBC believes that an earnings sharing mechanism continues to be beneficial and proposes an ESM similar to the 2007 PBR Plan with an equal sharing between customers and the Company for earnings above and below the allowed ROE established for each year by the Commission. The Company is not proposing a deadband as part of this PBR Plan. Instead, the Company is proposing an off-ramp provision with both financial and non-financial triggers.

Also, as in the 2007 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 in the subsequent year. 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 for the following year.

B&V supports FBC's decision to incorporate a similar ESM design to that employed in the 2007 PBR Plan. B&V's PBR Report states regard to FEI's 2004-2009 PBR Plan:

> *"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*

FBC is proposing a new efficiency carry-over mechanism (ECM) that incorporates some improvements from the ECM employed as part of FEI's 2004 - 2009 PBR Plan. The rationale for ECMs generally, and FBC'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 FEI 2004-2009 ECM

FBC is proposing to include an ECM based on FEI's 2004 – 2009 PBR Plan, but with significant enhancements.

The FEI 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. FBC, 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, FEI's 2004 PBR ECM did not recognize the permanent efficiency gains that were achieved in O&M expenditures.

The effectiveness of FEI's 2004 PBR Plan ECM can be enhanced in two ways:

7. by using a rolling carry-over approach; and
8. 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 (five years in the case of FBC'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 FEI's 2004 PBR Plan, this percentage is identified as the "rate base benefit factor" in FBC'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, FBC proposes to balance the PBR incentives and improve the effectiveness of FEI's 2004 PBR Plan ECM, by implementing a five year rolling-forward of the incremental O&M and capital savings calculated as the sum of:

9. 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

10. 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 12 percent.

The rate base benefit factor is representative of the avoided revenue requirements from reduced capital expenditures, which on average equal approximately 12 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 12 percent rate base benefit factor as well as an illustrative example of the proposed rolling ECM are provided in Appendix D5.

The effect of the 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 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 page 11 of its PBR Report (Appendix D1). SQIs were a key component of the 1996 and 2007 PBR plans and FBC proposes to continue with this feature, with appropriate updates to the SQIs themselves.

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 B6-8: Proposed 2014 PBR SQIs

Performance measure	Indicator	Benchmark
Emergency response time	Percent of calls responded to within two hours	85%
Telephone service factor	Percent of 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	97%
System Average Interruption Duration Index	Informational indicator- 3 year rolling average of SAIDI (average cumulative customer outage time)	---
System Average Interruption Frequency Index	Informational indicator- 3 year rolling average of SAIFI (average customer outages)	---
All injury frequency rate	Informational indicator - 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	---
Customer satisfaction index	Informational indicator	---

FBC will report to the Commission and stakeholders at the Annual Review to allow a review of the Company's performance for each of the SQIs. A full discussion of the improved SQIs is included in Appendix D6 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). FBC 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. The terms of reference of the Mid-term Assessment Review will be:

11. 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.
12. 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 Assessment 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. FBC 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 earnings of the utility differs significantly from its approved ROE, is the most common form of off-ramp provisions. FBC is proposing that the PBR Plan be reviewed if the post-sharing earnings of the Company

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

exceeds or drops below the allowed ROE by 200 basis points in any single year of the PBR term.

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. FBC 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, FBC 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 FBC. Triggering of the off-ramp provision would be warranted only if there is sustained serious degradation of the SQIs.

6.8 *ANNUAL REVIEW*

The 2007 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 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, FBC 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:

13. Customer and load growth and revenues;
14. Year-end and average customers, and other cost driver information including inflation;
15. Expenses (determined by the PBR formula plus flow through items);

[35] The 2007 PBR Plan had a trigger mechanism of 200 basis points above or below the allowed ROE that was not an "off-ramp". If this earnings threshold was exceeded the earnings variance (positive or negative) would be placed in a deferral account for review and disposition at the next Annual Review.

16. Capital expenditures (as determined by the PBR formula plus flow through items);
17. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
18. Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year ; and
19. Service Quality Indicator results.

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

Table B6-9 below provides a summary comparison of FBC's current PBR Plan proposal and the 2007 Plan.

1 **Table B6-9: FBC PBR Plans Comparison**

Item	2007 PBR Plan	2014 PBR Application
Term	Three year term proposed. A two year term from 2007-2008 was approved after NSP, three year extension to 2011 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 and Average Weekly Earnings will be used to determine inflation forecasts.
Productivity Improvement Factor (X-Factor)	Approved adjustment factors (i.e. X-Factors): 2% for 2007-2008, 3% for 2009, 1.5% for 2010-2011. Inflation in excess of 3% added to PIF to effectively cap CPI at 3% in 2009-2011.	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M was approved. 2005 approved O&M used as a base, adjusted for 2006 incremental costs and 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	Capital expenditures forecast annually.	Same formula as O&M. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%.
Other Cost Accounts	All other Cost Accounts reforecast annually.	All other Cost Accounts to be reforecast annually.
Exogenous Factors	These factors included directives of the BCUC or other competent regulatory agencies; acts of legislation or regulation of government, changes to GAAP, changes to actuarial evaluations, force majeur events, and other extraordinary events as agreed to by the parties in the Negotiated Settlement Process.	Similar factors, as set out in Section 6.3.3
Deferral and Flow Through Expenses & Revenues	Revenues and non-controllable expenses (such as power purchases, , interest expense, return on equity, pension/OPEB costs, 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 2007 PBR, with the addition of tax, property tax and insurance premiums.
Earnings Sharing Mechanism	A 50/50 earnings sharing mechanism was applied during this PBR. The difference between the allowed and actual ROE (within 2 percent of allowed) was shared equally between customers and shareholders.	Earnings sharing will be the same as in 2007 PBR - equal earnings sharing above and below the approved ROE.
End of Term Efficiency (Efficiency Carry-Over Mechanism)	None.	An ECM is proposed that considers capital and O&M benefits on a rolling five year basis.

Item	2007 PBR Plan	2014 PBR Application
Service Quality Indicators	A set of 13 SQIs and 1 informational indicator.	An improved set of 9 SQIs is proposed dealing with emergency response, customer service, employee safety and system reliability. 4 of the 9 SQIs are considered to be informational indicators.
Mid-term Review and Off Ramps	A provision for review of the PBR Plan after two years resulted in an extension of the Plan for a further three years.	A Mid-term 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 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. 2014 – 2018 RATE FORECASTS

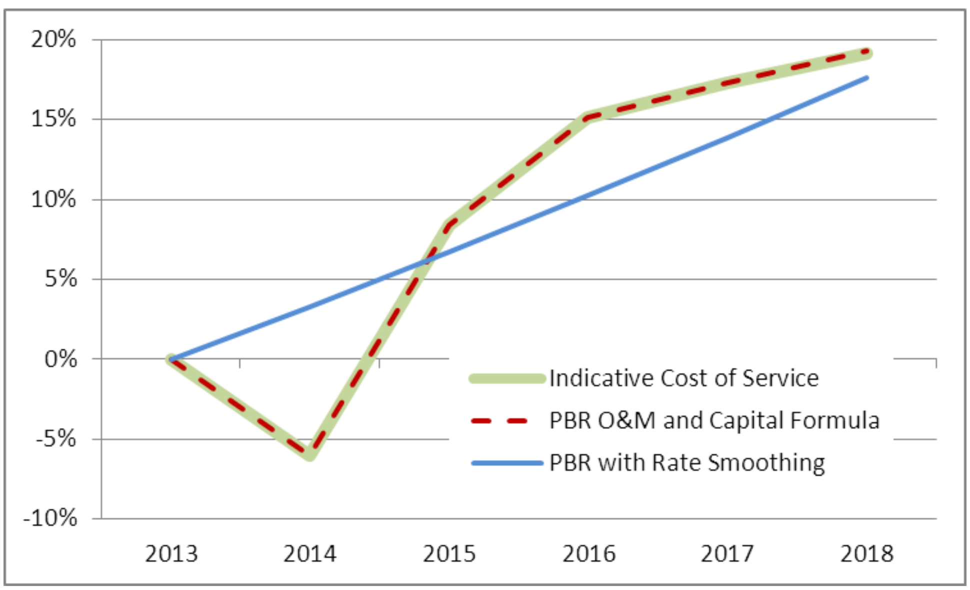
7.1 RATE STABILIZATION DEFERRAL MECHANISM

In this application FBC has proposed a Rate Stabilization Deferral Mechanism (RSDM) to mitigate variability in revenue requirements during the PBR period. The RSDM, which is described in Section D4.3.1, will be recognized as a deferred credit in rate base to be amortized over the PBR Period. The RSDM not only levelizes rate increases over the five year period, but results in a cumulative increase that is more than 1.5 percent lower than would result in the absence of rate smoothing, a result of the lower rate base in the earlier years.

7.2 2014 – 2018 RATE FORECASTS

The PBR mechanism proposed in this application results in rate increases that are nearly identical to those that would be likely required under cost of service regulation, before rate smoothing. The following graph compares annual rate increases under an indicative cost of service model to those under the proposed PBR Plan, and to rates using the proposed RSDM.

Figure B7-1 Comparison of Rate Increase Scenarios



FBC's proposed PBR Plan offers both regulatory efficiencies and the opportunity for lower rates for customers through the ESM as compared to the indicative Cost of Service approach. The RSDM not only reduces rate variability but lowers the overall rate impact over the 2014-2018 period.

8. CONCLUSION

B&V and FBC regard FBC'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*

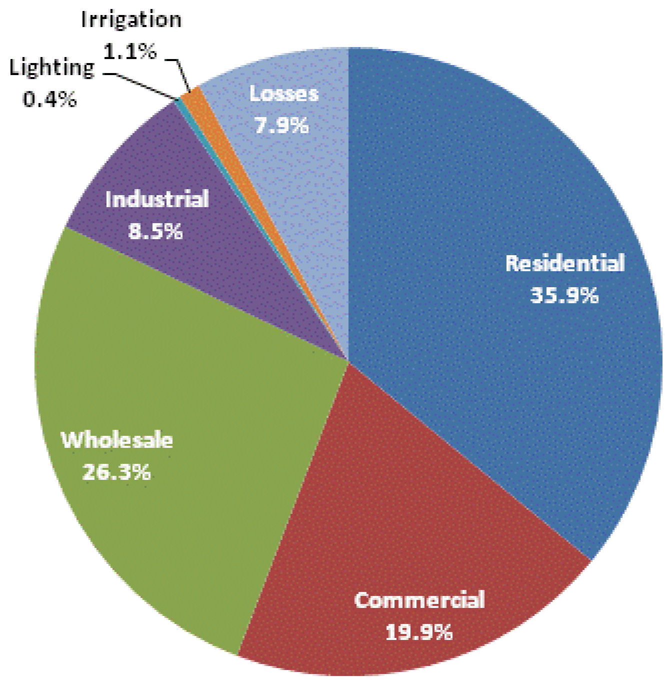
This section sets out the Company's forecasts for the PBR Period as follows:

- Section C1 provides FBC's load forecast and resulting forecast revenues at existing rates.
- Section C2 provides FBC's forecast power purchase and wheeling expense.
- Section C3 provide FBC's forecast of other revenue.
- Section C4 provides FBC's historical and forecast O&M with supporting departmental summaries and drivers.
- Section C5 provides FBC's historical and forecast capital expenditures by major capital category.

1. 2014 – 2018 LOAD FORECAST

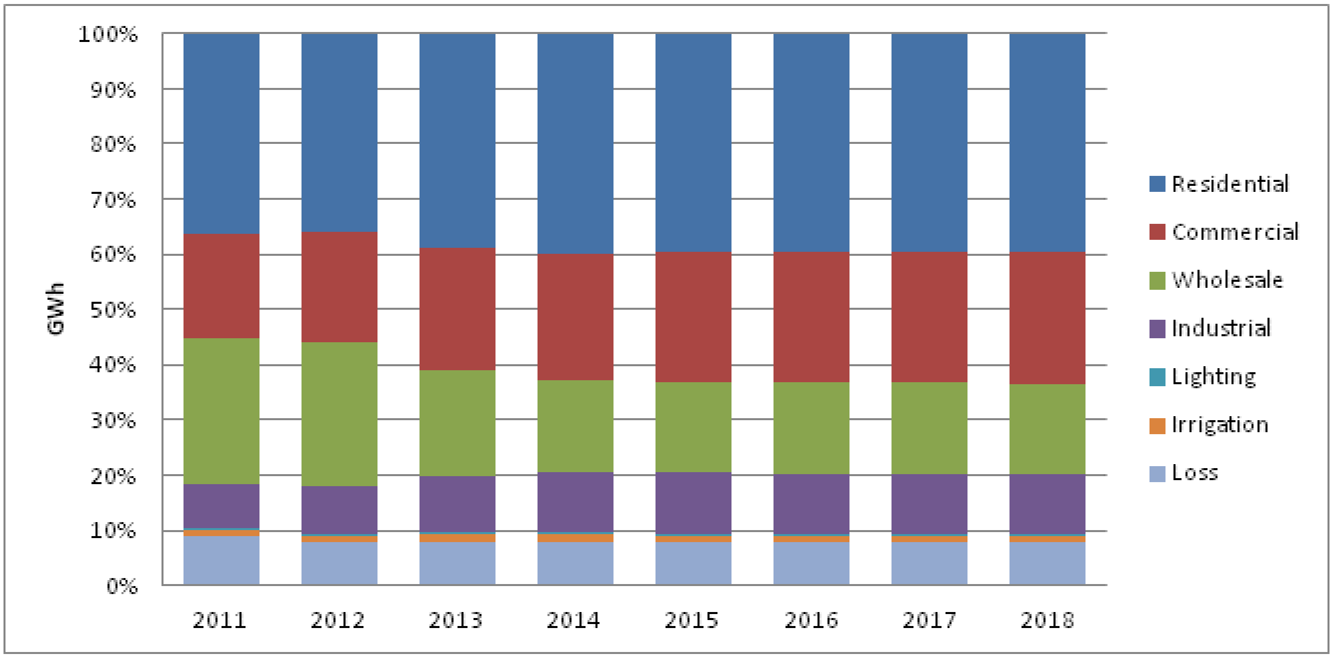
Gross system energy load is a mix of residential, commercial, wholesale, industrial, street lighting and irrigation loads and system losses. In 2012 the residential, commercial and wholesale loads represented the largest portion of the forecast at about 82 percent. The industrial load was around 9 percent, while the lighting and irrigation loads accounted for the about 1 percent of the total gross load. The remaining 8 percent of the gross load in 2012 was due to system losses.

Figure C1-1: 2012 Normalized Gross Load Energy Composition (%)



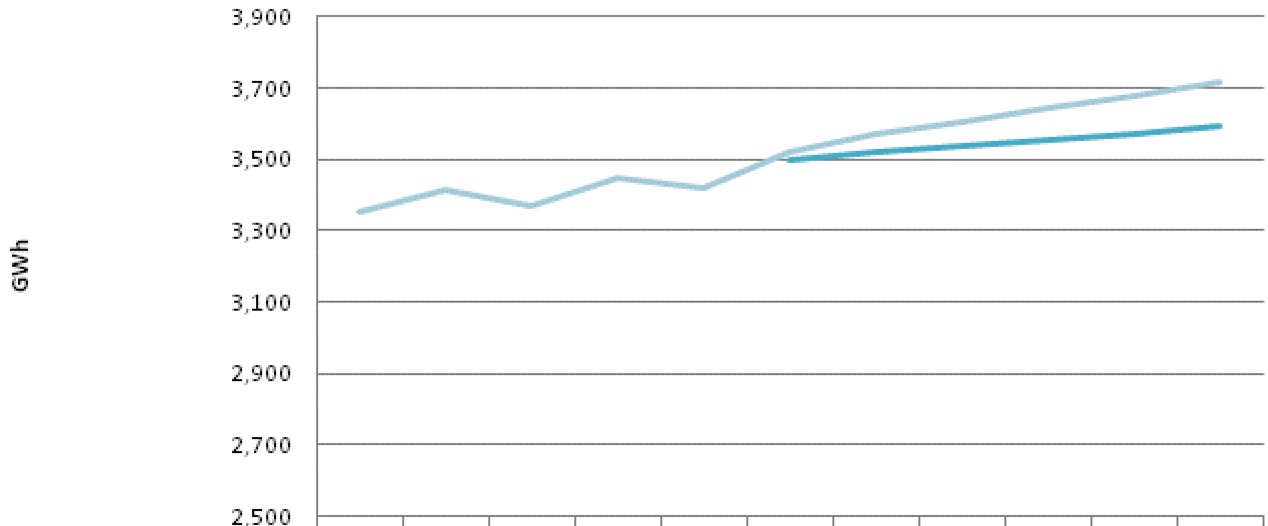
FBC's allocation of weather-normalized gross energy load for the years 2011, 2012 and the 2013 to 2018 after-savings forecast is shown in Figure C1-2. The after-savings forecast includes not only DSM savings but also other savings which consist of the Residential Conservation Rate (RCR), the future Consumer Information Portal program (CIP), the Advanced Metering Infrastructure (AMI) program and rate-driven impacts. These other savings are further explained in Section 3 - Demand Side Management and Other Savings.

Figure C1-2: Normalized and After-Savings Forecast Gross Load Energy Composition (%).



From 2014 to 2018 there are slight increases in the gross load forecast, which are mainly related to increases in the commercial sectors. The normalized and after-savings forecast gross energy consumption from the years 2008 to 2018 are shown below.

Figure C1-3: Normalized and Forecast Gross Load Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	3,351	3,416	3,369	3,447	3,422	3,520	3,570	3,607	3,642	3,675	3,715
After-Savings						3,496	3,519	3,537	3,554	3,572	3,596
After-Savings Growth	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%

1.1 *WEATHER NORMALIZATION*

In order to forecast loads, it is necessary to eliminate the contribution of weather effects (mainly due to temperature) on load growth prior to performing any statistical analysis. FBC accomplishes this through weather normalization, which adjusts historical temperature sensitive loads relative to normal weather. The Residential and Wholesale classes are the only ones to exhibit significant correlation between usage and temperature.

For the 2014 to 2018 energy forecast, monthly 10-year average Heating Degree Days and Cooling Degree Days (HDD and CDD) provided by Environment Canada are used to define the normal weather. A normalization model calculates sensitivity factors that relate sales to the HDD and CDD and then uses the results to normalize the actual loads. A more detailed account of the weather normalization methodology used by FBC can be found in Appendix E2, Section 2.

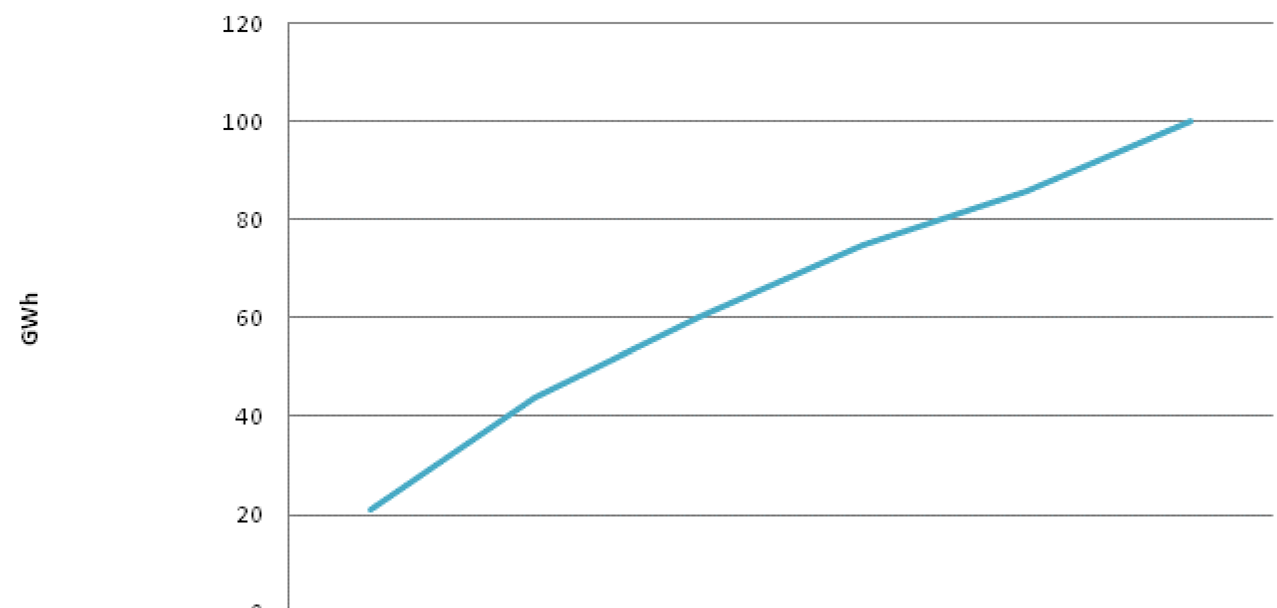
1.2 *DEMAND SIDE MANAGEMENT AND OTHER SAVINGS*

A forecast of incremental Demand Side Management (DSM) savings (excluding DSM already embedded in historical loads) by customer class is provided by the PowerSense department of FBC. This forecast is then deducted from the before-savings forecast developed by the Resource Planning department. The residential energy sales are further reduced by other savings from the RCR and CIP, but increased by recovered sales from the AMI-based revenue protection programs. The forecast for these programs are supplied by the Customer Service group.

Rate-driven savings due to price elasticity are also taken into account and deducted from the before-saving loads. This is independent of the RCR mentioned above and applied to all rate classes. In the absence of specific information with regards to price elasticity, FBC has applied the assumption of -0.05 elasticity made by BC Hydro[36], which is considered to be reasonable given its geographic proximity and similarities in terms of customer mix and behaviours.

Reductions in energy consumption due to incremental Demand Side Management (DSM) and other saving programs are forecast to increase from 21 GWh in 2013 to 100 GWh in 2018. All forecast values in this report are shown after being reduced by DSM and other savings unless explicitly stated otherwise.

Figure C1-4: Incremental DSM and Other Savings Forecast (GWh)



	2013	2014	2015	2016	2017	2018
DSM and Other Savings	21	44	60	75	86	100

1.3 *CITY OF KELOWNA*

FBC's acquisition of the distribution assets owned by the City of Kelowna (CoK) on March 31, 2013 added approximately 14,500 customers to the FBC system; approximately 1,500 commercial and 9 industrial customers, and the remainder residential, to the FBC system. The

[36] BCH 2012 IRP, App.2A, p. 14, http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix36.pdf, accessed as of April 12, 2013.

current load mix for CoK is approximately 45.4%, 32.6%, and 22.0% for the residential, commercial, and industrial loads respectively.

Due to the unavailability of sufficient historical load information prior to the transaction, it is not possible to ensure that the same forecast methods applied to the existing FBC load classes would also be reasonable to apply to the CoK load classes. Therefore the CoK load is forecast as a whole, and then allocated to the three load classes according in the proportions identified above. CoK before-savings load is forecast at the growth rate of 0.5%. This, together with the savings, gave a growth rate consistent with that which was provided during the application for the acquisition of the CoK utility assets. All forecast values in this report have taken the CoK integration into account unless explicitly stated otherwise.

1.4 *METHODOLOGY OVERVIEW*

The 2014 to 2018 forecast is based on household projections for the FBC direct service area from BC Stats, provincial Gross Domestic Product (GDP) projections by the Conference Board of Canada (CBOC), as well as load growth and survey information. FBC uses the following main inputs for determining customer and sales forecast:

- Relationship of residential customer count to population;
- Relationship of commercial sales to GDP;
- Industrial load surveys and forecast GDP growth rates for industrial sectors; and
- Survey information for the wholesale class;

More detailed information pertaining to the methodologies used by FBC can be found in the Load Forecast Appendix E2.

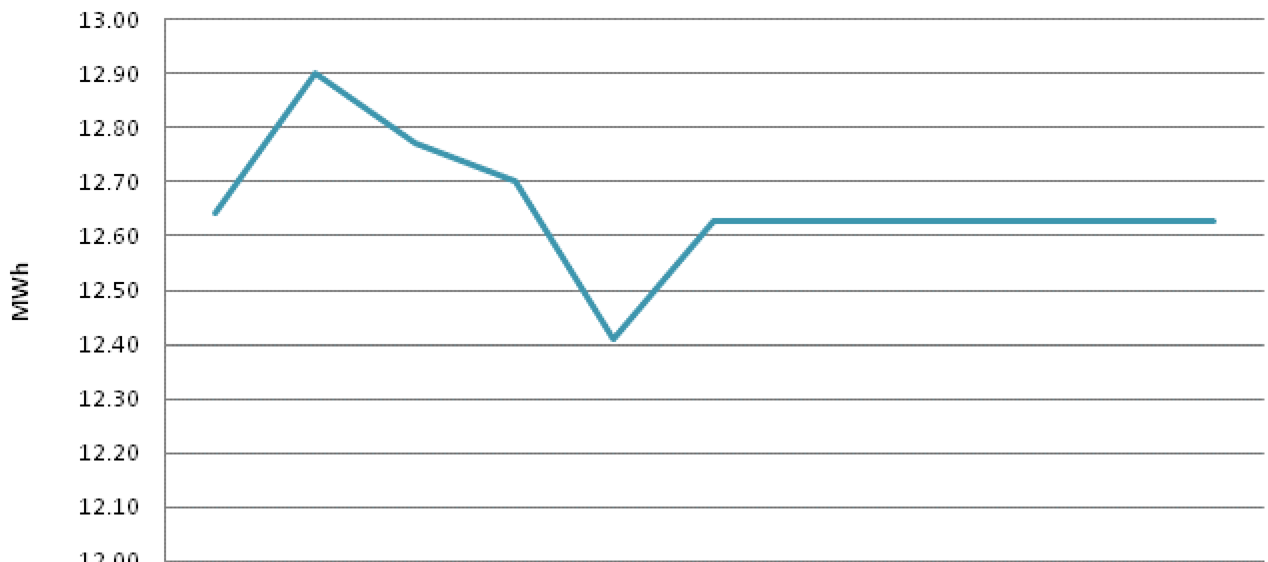
1.4.1 Residential

Residential demand is influenced by many factors including but not limited to home characteristics, household consumption patterns, type of housing and weather. Total before-savings energy demand for the Residential class (excluding CoK) is the product of the annual residential customer count and the residential use per customer (UPC). As mentioned in Section 4, the residential customer counts from the aquistion of the CoK are forecast seperatly.

Forecast residential customer counts are determined from a regression of the year-end customer accounts on population in the FBC direct service area. The population forecast for the FBC service area is provided by BC Statistics.

The residential UPC is calculated by taking the average of the normalized UPC from the years 2010 to 2012. This UPC is then assumed to remain constant from 2013 onward at 12.63 MWh, since there is no statistically valid evidence of either an upward or downward trend.

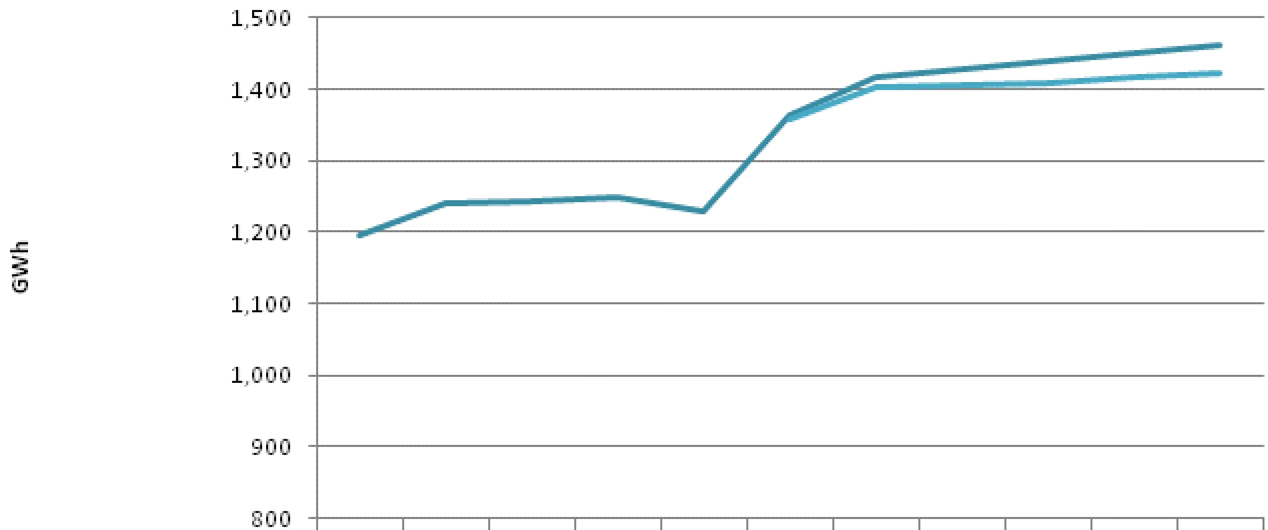
Figure C1-5: Normalized and Forecast Residential Before-Saving UPC (MWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPC	12.64	12.90	12.77	12.70	12.41	12.63	12.63	12.63	12.63	12.63	12.63
UPC Growth	-0.8%	2.1%	-1.0%	-0.5%	-2.3%	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%

Once the customer count, UPC and CoK energy usage have been calculated, the final residential customer usage can be calculated as the sum of the residential load excluding CoK and the residential CoK load. Below is the normalized and forecast residential customer usage from 2008 to 2014.

Figure C1-6: Normalized and Forecast Residential Energy Consumption (GWh)

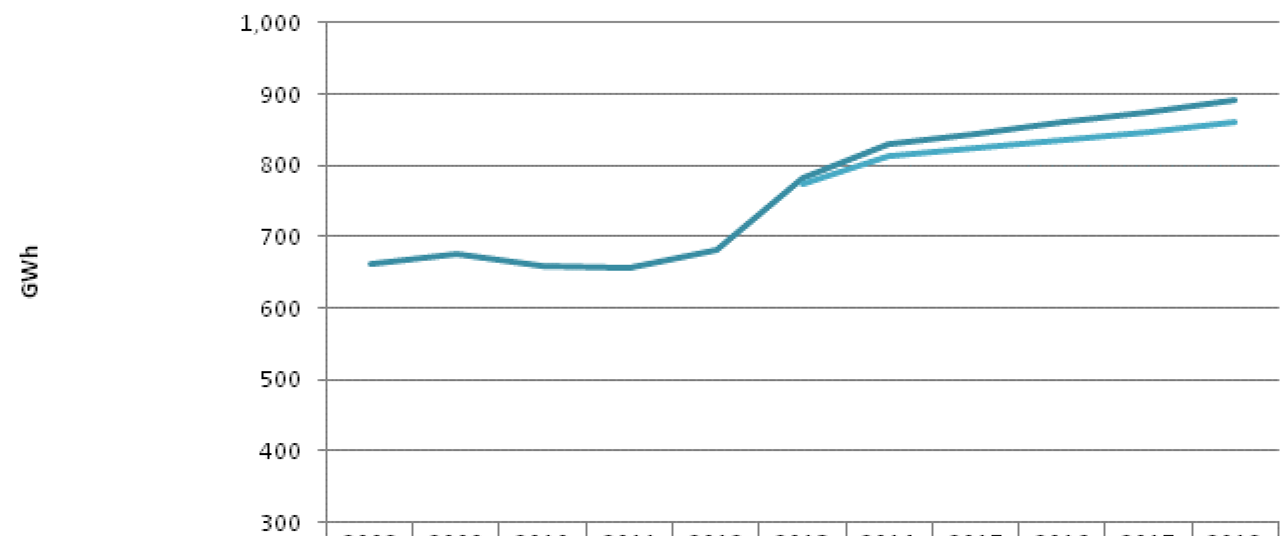


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	1,196	1,239	1,242	1,249	1,229	1,364	1,416	1,427	1,438	1,450	1,462
After-Savings						1,359	1,402	1,405	1,409	1,417	1,422
After-Savings Growth	2.6%	3.6%	0.2%	0.6%	-1.6%	10.6%	3.2%	0.2%	0.3%	0.6%	0.4%

1.4.2 Commercial

The commercial class is forecast based on a regression of load on the provincial GDP supplied by the CBOC. Provincial GDP was used to forecast since GDP data for the FBC direct service area were not available. Below is the actual and forecast commercial consumption for the years 2008 – 2018.

Figure C1-7: Actual and Forecast Commercial Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	661	675	660	657	681	781	829	845	861	874	893
After-Savings						773	813	825	837	845	860
After-Savings Growth	1.7%	2.2%	-2.3%	-0.4%	3.6%	13.6%	5.1%	1.5%	1.4%	1.1%	1.8%

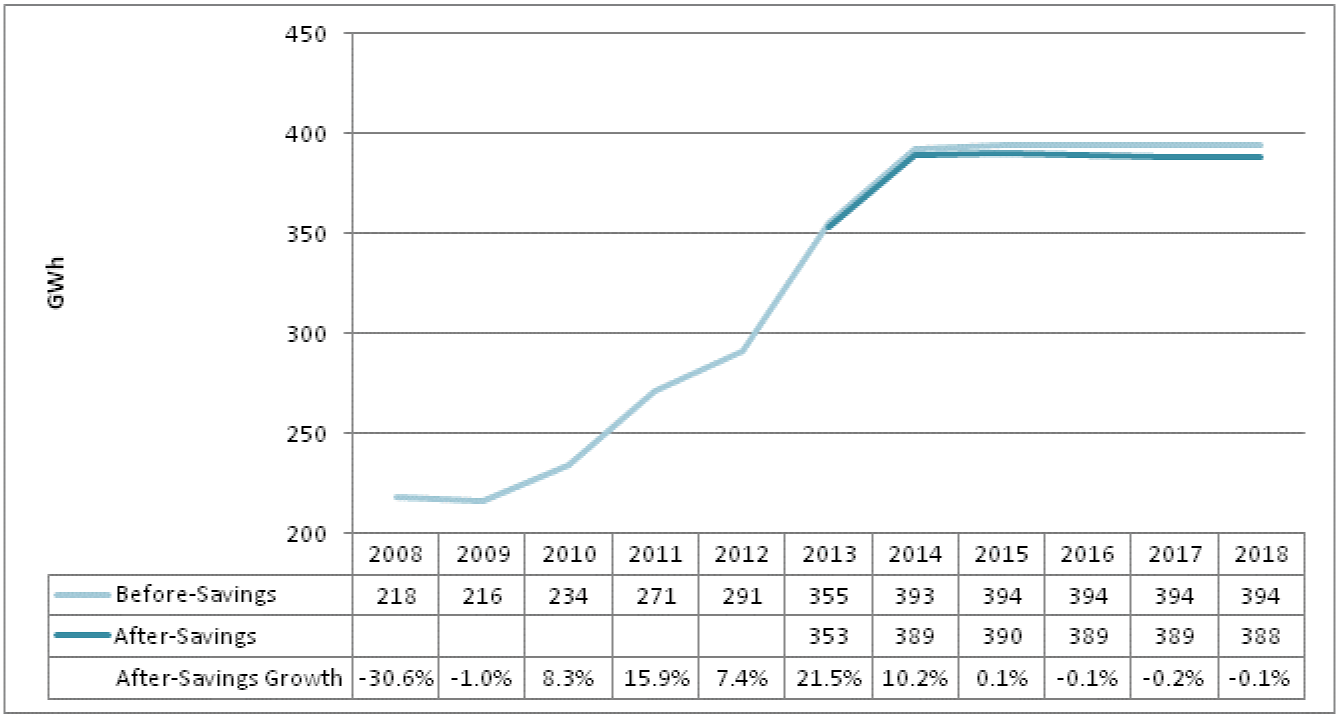
1.4.3 Industrial

The Industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of 2012 loads by the corresponding provincial GDP growth rates for individual industries.

Load surveys are sent to all industrial customers and request their anticipated use for the next 5 years. Surveys are sent out because FBC believes that individual industrial customers have the best understanding of what their future energy usage will be. This year we received 72% (28 of 39) of the surveys sent out, which represents 79% percent of the total industrial load.

Beginning in April 2013, the loads of the nine CoK industrial customers will be included as direct customers of FBC. The projected industrial loads are listed below for 2014- 2018 and the actual and forecast industrial consumption for the year 2008 – 2018.

Figure C1-8: Actual and Forecast Industrial Energy Consumption (GWh)



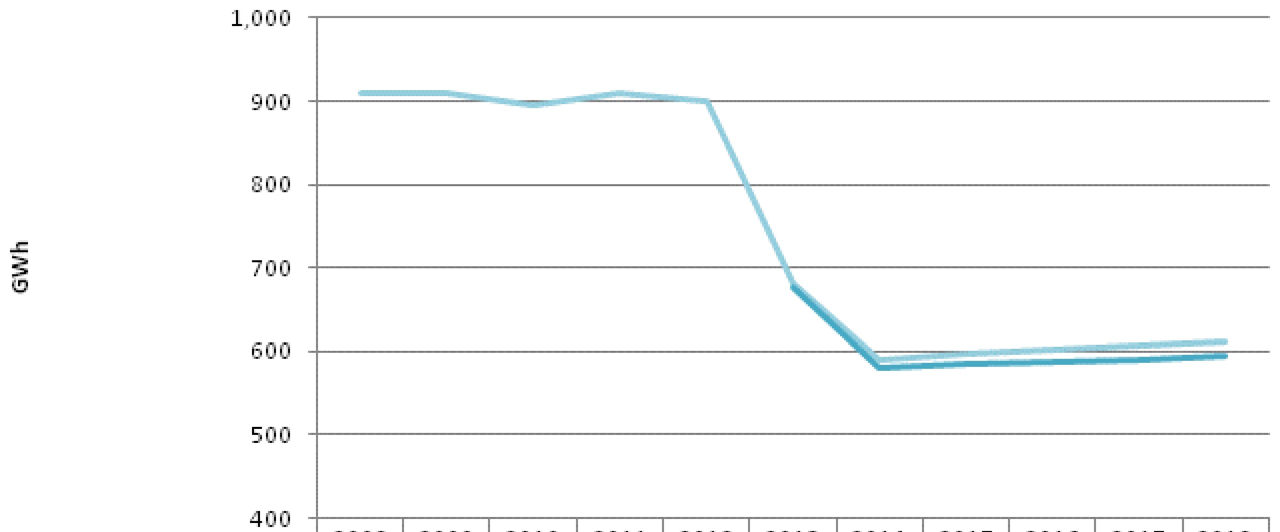
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	218	216	234	271	291	355	393	394	394	394	394
After-Savings						353	389	390	389	389	388
After-Savings Growth	-30.6%	-1.0%	8.3%	15.9%	7.4%	21.5%	10.2%	0.1%	-0.1%	-0.2%	-0.1%

1.4.4 Wholesale

FBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems. These wholesale customers have a load composition that is a mix of residential, commercial, industrial and street light customers, in which the residential and commercial sectors play the main roles.

The wholesale class is forecast from survey information from each of the individual wholesale customer's. FBC believes that the individual wholesalers have a better understanding of their customers and the potential for increases and decreases in load in their areas than it does. The wholesale customers responded with their forecast growth projections. The projected wholesale loads from 2014- 2018 are listed below along with the wholesale normalized and forecast loads for the year 2008 – 2018. The decline in growth in 2013 is due to the CoK being absorbed into the FBC direct system. This impact is fully observed in 2014.

Figure C1-9: Normalized and Forecast Wholesale Energy Consumption (GWh)

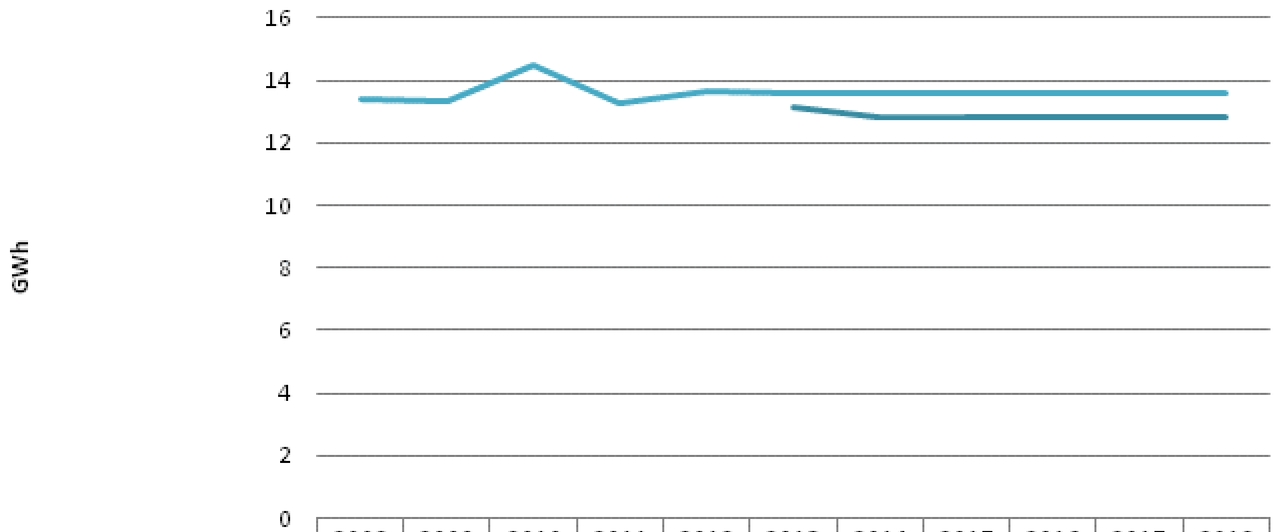


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	908	908	895	910	899	682	591	596	602	607	613
After-Savings						677	581	584	587	590	594
After-Savings Growth	3.4%	0.0%	-1.4%	1.6%	-1.2%	-24.7%	-14.1%	0.5%	0.5%	0.5%	0.5%

1.4.5 Lighting

The lighting load consists of street lights and varies little from year to year. The 5 year trend analysis from the years 2008 to 2012 is used to forecast this class. The before-savings lighting load is projected to be 13.6 GWh for the forecast period. The actual and forecast energy consumption from 2008 – 2018 are listed below.

Figure C1-10: Actual and Forecast Lighting Energy Consumption (GWh)

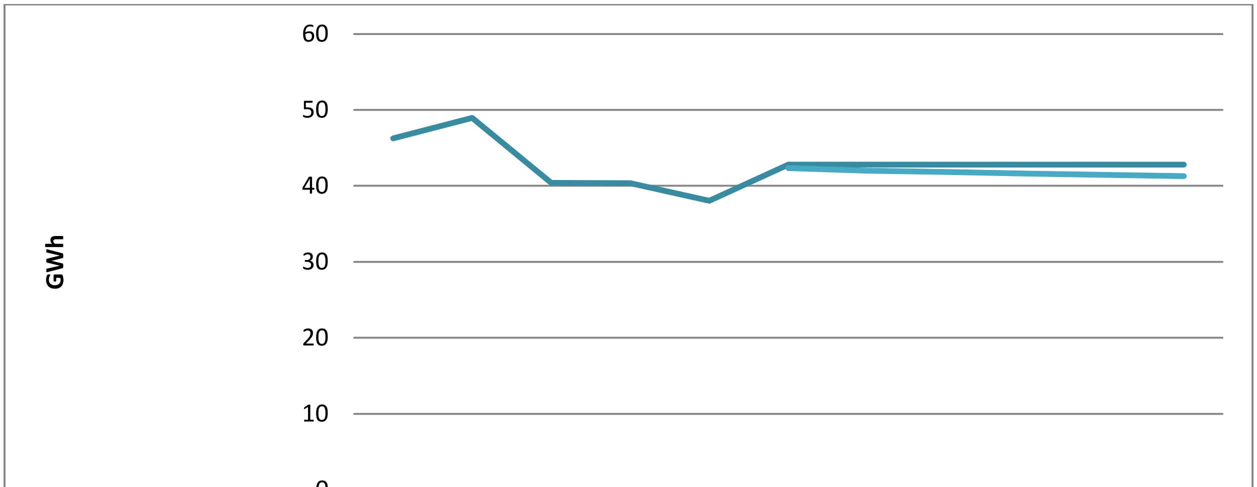


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	13	13	14	13	14	14	14	14	14	14	14
After-Savings						13	13	13	13	13	13
After-Savings Growth	4.5%	-0.8%	8.9%	-8.6%	3.0%	-3.5%	-2.8%	0.0%	0.0%	0.0%	0.0%

1.4.6 Irrigation

Due to differences in acreage, crop types and energy use patterns and the complexity of economic and environmental issues affecting irrigation customers, growth patterns for energy sales in this class are variable. Because of this variability, the before-savings forecast is assumed a five year average from 2008 to 2012. Below is the actual and forecast irrigation energy consumption from 2008 to 2018.

Figure C1-11: Actual and Forecast Irrigation Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	46	49	40	40	38	43	43	43	43	43	43
After-Savings						42	42	42	42	41	41
After-Savings Growth	-4.4%	5.9%	-17.5%	-0.1%	-5.8%	11.4%	-0.8%	-0.4%	-0.4%	-0.4%	-0.4%

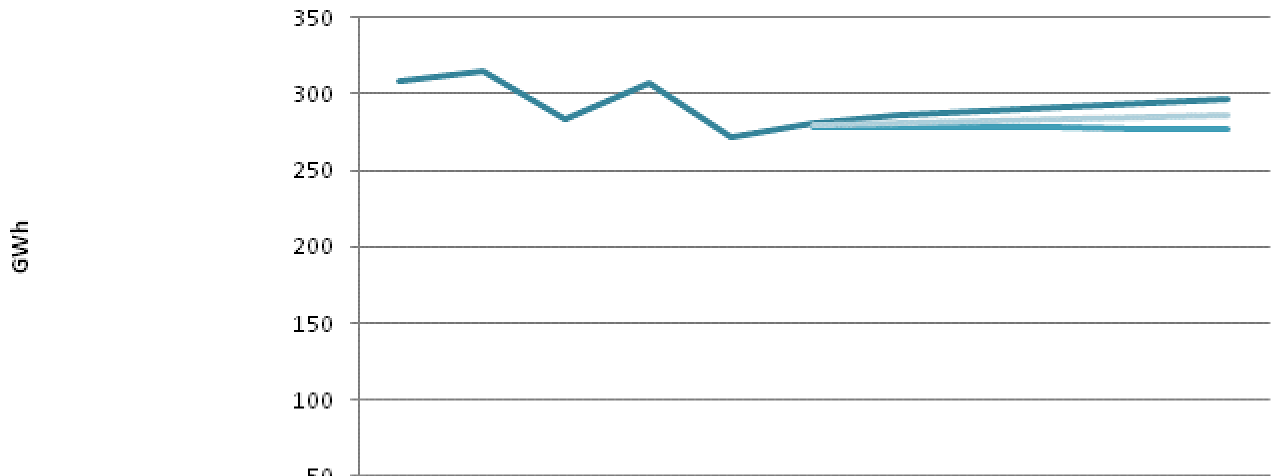
1.4.7 Losses

System losses consist of:

20. Losses in the transmission and distribution system;
21. Company use;
22. Losses due to wheeling through the BC Hydro system; and
23. Unaccounted-for energy (meter inaccuracies and theft)

Without an operational AMI and further study, the losses can only be estimated at this time. Detailed analysis of billing reports of individual accounts for 2011 and 2012 established 8% as the gross loss rate for use over the forecasting period. AMI loss reduction due to a reduction in illegal grow-op sites is expected to further reduce the losses in future. Note that there is no need to further adjust for impacts of the Okanagan Transmission Reinforcement project as in the 2012-2013 RRA because with completion of the project, its impacts are now embedded in the historical load data.

Figure C1-12: Normalized and Forecast Energy Losses (GWh)



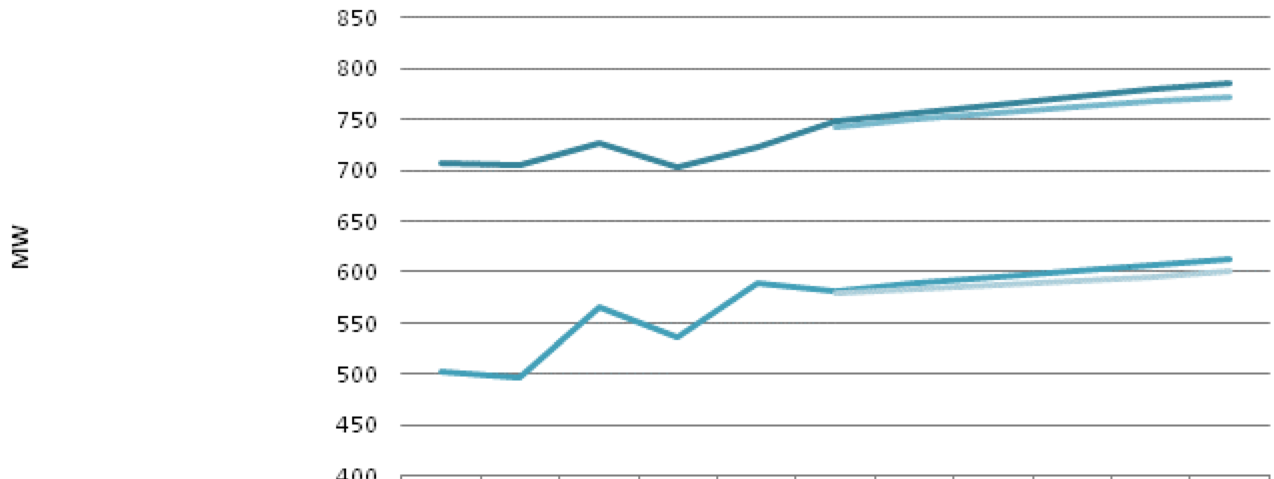
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	309	315	284	307	271	282	286	289	291	294	297
After-Savings						278	278	278	278	277	277
After-Savings Growth	-10.8%	2.1%	-10.1%	8.4%	-11.8%	2.6%	0.1%	-0.1%	-0.1%	-0.2%	0.0%
After-saving without AMI						280	281	282	284	285	286

1.4.8 Peak Demand

Peak demand is affected by economic activity, the number of customers, use per customer and temperature. The peak demand forecast is calculated by escalating ten years of historical peak load data by the actual historical energy load growth rates and then averaging the outputs for each month as well as for seasonal peaks.

Normalized winter peak and summer peaks for the years 2008 – 2012 and forecast peaks for 2013-2018 are listed below.

Figure C1-13: Normalized and Forecast Winter and Summer Peaks (MW)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings Winter Peak	707	704	726	702	723	748	757	764	771	779	786
After-Savings Winter Peak						743	750	756	761	767	772
Before-Savings Summer Peak	502	496	566	537	589	581	590	595	601	606	613
After-Savings Summer Peak						579	584	588	592	595	600

1.4.9 Summary Tables

Table C1-1: Normalized Energy Sales and After-Savings Forecast

Energy Sales (GWh)	Actual and Normalized 2008	2009	2010	2011	2012	Forecast 2013	2014	2015	2016	2017	2018
Residential	1,196	1,239	1,242	1,249	1,229	1,359	1,402	1,405	1,409	1,417	1,422
Commercial	661	675	660	657	681	773	813	825	837	845	860
Wholesale	908	908	895	910	899	677	581	584	587	590	594
Industrial	218	216	234	271	291	353	389	390	389	389	388
Lighting	13	13	14	13	13	13	13	13	13	13	13
Irrigation	46	49	40	40	38	42	42	42	42	41	41
Net	3,042	3,100	3,085	3,140	3,151	3,218	3,240	3,258	3,276	3,295	3,318
Losses	309	315	284	307	271	278	278	278	278	277	277
Gross	3,351	3,416	3,369	3,447	3,422	3,496	3,519	3,537	3,554	3,572	3,596
System Peak											
Winter Peak (MW)	707	704	726	702	723	743	750	756	761	767	772
Summer Peak (MW)	502	496	566	537	589	579	584	588	592	595	600

Table C1-2: Annual Change by Customer Class (%)

	Actual and Normalized					Forecast					
Energy Sales (GWh)	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	2.6%	3.6%	0.2%	0.6%	-1.6%	10.6%	3.2%	0.2%	0.3%	0.6%	0.4%
Commercial	1.7%	2.2%	-2.3%	-0.4%	3.6%	13.6%	5.1%	1.5%	1.4%	1.1%	1.8%
Wholesale	3.4%	0.0%	-1.4%	1.6%	-1.2%	-24.7%	-14.1%	0.5%	0.5%	0.5%	0.5%
Industrial	-30.6%	-1.0%	8.3%	15.9%	7.4%	21.5%	10.2%	0.1%	-0.1%	-0.2%	-0.1%
Lighting	4.5%	-0.8%	8.9%	-8.6%	1.9%	-2.4%	-2.8%	0.0%	0.0%	0.0%	0.0%
Irrigation	-4.4%	5.9%	-17.5%	-0.1%	-5.8%	11.4%	-0.8%	-0.4%	-0.4%	-0.4%	-0.4%
Net	-0.8%	1.9%	-0.5%	1.8%	0.3%	2.1%	0.7%	0.6%	0.5%	0.6%	0.7%
Losses	-10.8%	2.1%	-10.1%	8.4%	-11.8%	2.6%	0.1%	-0.1%	-0.1%	-0.2%	0.0%
Gross	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%
System Peak											
Winter Peak (MW)	0.5%	-0.4%	3.1%	-3.3%	2.9%	2.8%	1.0%	0.8%	0.7%	0.8%	0.6%
Summer Peak (MW)	-3.4%	-1.3%	14.1%	-5.2%	9.8%	-1.8%	0.9%	0.7%	0.7%	0.6%	0.8%

Table C1-3: Actual and Forecast Year-End Customer Count

Energy Sales (GWh)	Actual 2008	2009	2010	2011	2012	Forecast 2013	2014	2015	2016	2017	2018
Residential	95,502	96,565	97,883	98,795	99,228	112,740	113,589	114,521	115,508	116,544	117,600
Commercial	11,216	11,308	11,419	11,525	11,811	13,589	13,847	14,114	14,368	14,576	14,879
Wholesale	7	7	7	7	7	6	6	6	6	6	6
Industrial	36	33	35	36	39	48	48	48	48	48	48
Lighting	1,910	1,874	1,830	1,803	1,739	1,742	1,742	1,742	1,742	1,742	1,742
Irrigation	1,048	1,066	1,075	1,092	1,091	1,091	1,091	1,091	1,091	1,091	1,091
Total Direct	109,719	110,853	112,249	113,258	113,915	129,216	130,323	131,521	132,763	134,007	135,366
Annual Change By Customer Class (%)											
Residential	2.0%	1.1%	1.4%	0.9%	0.4%	13.6%	0.8%	0.8%	0.9%	0.9%	0.9%
Commercial	1.9%	0.8%	1.0%	0.9%	2.5%	15.1%	1.9%	1.9%	1.8%	1.5%	2.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	-14.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	-5.3%	-8.3%	6.1%	2.9%	8.3%	23.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Lighting	-4.1%	-1.9%	-2.3%	-1.5%	-3.5%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Irrigation	1.7%	1.7%	0.8%	1.6%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Direct	1.9%	1.0%	1.3%	0.9%	0.6%	13.4%	0.9%	0.9%	0.9%	0.9%	1.0%

1.5 *REVENUE FORECAST*

Revenues are a function of load and the rate applicable at the time the energy is consumed. FBC has developed a reasonable forecast of revenues by applying the total load forecast to the currently approved rates (as at January 1, 2013) for each customer class.

Table C1-4 below summarizes the revenues projected for 2013 and forecast for 2014 through 2018, at 2013 rates.

Table C1-4: Forecast Sales Revenue at Existing Rates ($ millions)

	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential	160.2	165.4	165.9	166.4	167.5	168.3
Commercial	69.2	75.7	76.7	77.7	78.4	79.6
Industrial	25.0	29.9	29.9	29.8	29.6	29.6
Wholesale	50.5	41.9	42.2	42.4	42.7	42.9
Total	**304.9**	**312.9**	**314.6**	**316.3**	**318.2**	**320.4**

Note: Commercial includes Lighting and Irrigation classes.

2. POWER PURCHASE EXPENSE

This section includes a review of the power purchase expense (PPE) realized in 2012, the 2013 Projection, taking into account FBC's actual results to April 30, 2013, and the forecast for 2014. Also included in this section are forecasts of wheeling and expense and water fees.

As shown in Table C2-1 below, power purchase expense, net of market mitigation, is forecast at $84.3 million for 2013 and $87.8 million for 2014 as compared to the actual cost of $76.0 million for 2012. As will be discussed in the following sections, the expected increase from 2012 to 2013 is primarily due to an increase in forecast load, annual increases to the Brilliant and BC Hydro rates, and higher market prices. The increase from 2013 to 2014 is mainly due to an increase in forecast load.

Table C2-1: Total Power Purchase Expense ($ thousands)

		2012 Actual	2013 Projection	2014 Forecast
	Power Purchase Expense	**($000s)**		
1	Approved	87,149	91,942	
2	Actual / Forecast	75,999	84,266	87,814
	Gross Load	**(GWh)**		
3	Approved	3,490	3,534	
4	Actual / Forecast	3,413	3,461	3,519

2.1 *SUMMARY OF POWER SUPPLY RESOURCES*

FBC uses a combination of Company-owned generation entitlements, firm contracted supply and market purchases to meet its load requirements. The Company's firm resources consist of:

a) Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned and operated by FBC. The costs associated with FBC owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year to year timing difference;

b) The Brilliant Power Purchase Agreement (BPPA) (a 125 MW contract terminating in 2056), and an amendment to the BPPA which reflects the purchase of the Brilliant Upgrade power (20 MW) and the Brilliant Tailrace Capacity agreement (5 MW);

c) A power purchase agreement with BC Hydro (200 MW) under BC Hydro Rate Schedule 3808 (BC Hydro PPA). The current 20 year contract (the 1993 PPA) expires on September 30, 2013, however BC Hydro and FBC have recently entered into a replacement PPA (the New PPA) and associated agreements that, subject to BCUC approval, commences on October 1, 2013.;

d) A number of small Independent Power Producer (IPP) contracts, and;

e) A number of market purchase arrangements.

FBC has also entered into a 40-year capacity purchase agreement with the Waneta Expansion Limited Partnership (WAX CAPA). The Waneta Expansion (WAX) facility is expected to come into service in 2015 and therefore is not included in the power purchase expense actual and forecast figures for the 2012 to 2014 period. The advance purchase of winter capacity blocks from Powerex will meet the majority of the peak loads until the WAX CAPA capacity is available.

A primary objective of FBC's power supply portfolio planning is to ensure that the Company has sufficient firm resources to meet expected load requirements to ensure the availability of cost effective reliable power for FBC's customers and to prudently manage exposure to the cost and availability of market power supplies. The Company currently has long-term, firm resources from which it can supply over 99 percent of the annual energy requirements. The small shortfall is due to system capacity constraints during peak load days.

The nature of FBC's contracted resources, in particular the BC Hydro PPA, does provide the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. The forecast of Power Purchase Expense, as a result, has typically been developed based on relying on first using FBC's owned and long term firm contracted resources before relying on the market purchases and then making an adjustment for the potential for market savings through displacement of BC Hydro PPA purchases. As will be discussed in the following sections, this approach was the basis for the 2012 and 2013 approved power purchase expense amounts while the approach to develop the 2014 power purchase expense forecast has been modified to allow a forecast of BC Hydro PPA and market purchases that more accurately reflects the expected contribution of these resources to meeting FBC's requirements.

2.2 REVIEW OF 2012 POWER PURCHASE EXPENSE

The winter of 2011/2012 experienced above-average snow packs and run-off, resulting in above average water supply in the Pacific Northwest. High water supply combined with ongoing moderate natural gas prices and a growing base of variable and unpredictable wind generation in the Pacific Northwest provided significant opportunities to obtain market energy at rates below those of the BC Hydro PPA. These impacts are reflected in Table C2-2 below which shows actual BC Hydro purchases were much lower than forecast while market purchases were much higher. Overall purchases were also lower than forecast because of reduced loads compared to forecast.

FBC gross load in 2012 was 77 GWh below the approved 2012 forecast. As shown in Table C2-2, 2012 power purchase expense was $11.2 million below the approved forecast principally due to a combination of the lower loads than forecast, and favourable market conditions allowing FBC to displace forecast purchases under the BC Hydro PPA with market purchases.

Table C2-2: Total Power Purchase Expense ($ thousands)

		2012 Approved	2012 Actual	Difference
1	Brilliant	35,601	35,591	(10)
2	BC Hydro	51,426	26,037	(25,389)
3	Independent Power Producers	155	180	25
4	Market and Contracted Purchases	2,645	14,366	11,721
5	Surplus Revenues	(427)	-	427
6	Special and Accounting Adjustments	(1)	(162)	(161)
7	Balancing Pool	-	(13)	(13)
8	TOTAL (before adjustments)	89,399	75,999	(13,400)
9	PPE Adjustment	(2,250)	0	2,250
10	TOTAL	87,149	75,999	(11,150)
11	Gross Load (GWh)	3,490	3,413	(77)

Note: Minor differences due to rounding.

Note that the Power Purchase Expense Adjustment (PPE Adjustment) shown in the table is a combination of the $750 thousand adjustment proposed by the Company in its 2012-2013 Revenue Requirements Application and the further $1.5 million adjustment ordered by the Commission in the 2012-2013 RRA Decision to account for potential market savings in both 2012 and 2013. Actual savings are imbedded in the difference between the reduced BC Hydro purchases and the increased market purchases and therefore it does not appear as a line item in the actual results. Overall savings are captured in the Power Purchase Expense Variance deferral account and will flow back to customers.

2.3 *REVIEW OF 2013 POWER PURCHASE EXPENSE*

The winter of 2012/2013 saw average snow pack and upward pressure on the natural gas prices in the region. As a result, market prices in January through March of 2013 have been more volatile and generally higher than over the same period last year. Even with increased market prices compared to 2012, there have been opportunities to obtain market energy at rates below those of the BC Hydro PPA, however the overall savings are lower. It is anticipated that these conditions will continue throughout 2013

.

As shown in Table C2-3 below FBC gross load is forecast to be 73 GWh below the approved 2013 forecast by year end, while power purchase expense is forecast to be $7.7 million below the approved 2013 forecast, primarily as a result of reduced BC Hydro purchases due to reduced load and displacement with market purchases. This is illustrated by the lower than forecast BC Hydro PPA costs and the higher than forecast costs of market purchases. Any savings overall at year-end will flow back to customers through the Power Purchase Expense Variance deferral account.

Table C2-3: Total Power Purchase Expense ($ thousands)

		2013 Approved	2013 Projection	Difference
1	Brilliant	36,785	36,781	(4)
2	BC Hydro	54,482	31,021	(23,461)
3	Independent Power Producers	158	229	71
4	Market and Contracted Purchases	3,216	16,094	12,880
5	Surplus Revenues	(447)	(308)	139
6	Special and Accounting Adjustments	-	14	14
7	Balancing Pool	-	435	435
8	TOTAL (before adjustments)	94,192	84,266	(9,926)
9	PPE Adjustment	(2,250)	-	2,250
10	TOTAL	91,942	84,266	(7,676)
11	Gross Load (GWh)	3,534	3,461	(73)

Note: Minor differences due to rounding.

2.4 *2014 POWER PURCHASE EXPENSE FORECAST*

The forecast for 2014 compared to the 2013 forecast approved as part of the 2012-2013 Revenue Requirement is shown below in Table C2-4. The 2014 forecast is $6.4 million less than the approved 2013 forecast before taking into account the 2013 PPE Adjustment of $2.25 million, and $4.1 million less than the final approved 2013 forecast.

As discussed earlier, the approach used to develop the power purchase expense forecast for 2014 differs from the approach used to develop the 2012 and 2013 forecast used in FBC's 2012-2013 Revenue Requirement Application. The 2012 and 2013 forecasts were based on first fully utilising existing firm resources, including the BC Hydro PPA, before recognising the potential for savings that could be achieved by using market purchases to displace those that would otherwise be made under the BC Hydro PPA. The PPE adjustment was then applied as a proxy for any market savings. In contrast, the 2014 forecast is based on a more detailed assessment of expected purchases from BC Hydro under the New PPA that takes into account FBC's expected load profile, the ability to lock in market savings in advance through contracted term purchases, and a forecast of any additional market savings that may be achieved in real time throughout the year through active management of the power supply portfolio.

As shown in Table C2-4, year over year the approach results in a much lower forecast of purchases under the BC Hydro PPA and a much higher forecast of contracted term or real time market purchases. As such, under this approach the 2014 forecast amounts already recognise the potential for market savings against FBC's firm resources and therefore there is no additional PPE adjustment to the forecast. Other factors that impact the 2014 forecast are the 15 GWh reduction in expected gross load and an adjustment to the rates under FBC's long term Brilliant contract. Overall, this has resulted in a 2014 forecast of $87.8 million that is $6.4 million lower than the 2013 approved (excluding the PPE adjustment), and $4.4 million below the approved 2013 power purchase expense.

Table C2-4: 2014 Forecast vs. Approved 2013 Power Purchase Expense ($ thousands)

		2013 Approved	2014 Forecast	Difference
1	Brilliant	36,785	35,764	(1,021)
2	BC Hydro[1]	54,482	37,201	(17,281)
3	Independent Power Producers	158	162	4
4	Market and Contracted Purchases	3,216	15,281	12,065
5	Surplus Revenues	(447)	(594)	(147)
6	Special and Accounting Adjustments	-	-	-
7	Balancing Pool	-	-	-
8	TOTAL (before adjustments)	94,192	87,814	(6,378)
9	PPE Adjustment	(2,250)	-	2,250
10	TOTAL	91,942	87,814	(4,128)
11	GWh	3,534	3,519	(15)

[1] BC Hydro 2014 forecast is based on BC Hydro's approved rates effective April 1, 2013

Note: Minor differences due to rounding.

The 2014 Forecast is further compared to the 2013 year end forecast in Table C2-5. The 2013 year end forecast is based on actual results to April 30, 2013 and an updated forecast to the end of 2013. This comparison shows the 2014 forecast is approximately $3.5 million greater than the 2013 year end forecast. This is largely driven by higher forecast loads in 2014, higher market prices and greater use of BC Hydro purchases.

Table C2-5: 2014 Forecast vs. 2013 Year End Forecast ($ thousands)

		2013 Projection	2014 forecast	Difference
1	Brilliant	36,781	35,764	(1,017)
2	BC Hydro	31,021	37,201	6,180
3	Independent Power Producers	229	162	(67)
4	Market Purchases	16,094	15,281	(813)
5	Surplus Revenues	(308)	(594)	(286)
6	Special and Accounting Adjustments	14	-	(14)
7	Balancing Pool	435	-	(435)
8	TOTAL	84,266	87,814	3,548
11	Gross Load (GWh)	3,461	3,519	58

Note that the 2014 forecast of BC Hydro PPA costs is based on BC Hydro's most recent approved rate increase effective April 1, 2013 but does not take into account future rate increases. The next BC Hydro rate increase is expected to be effective April 1, 2014 and would directly impact these costs. For example a 5 percent increase in BC Hydro rates on April 1, 2014 could increase the annual PPE expense by up to $1.8 million. Likewise a 5 percent change in average market prices could impact market purchases by up to $760 thousand. Any variances between actual and forecast power purchase expense will continue to be captured in the Power Purchase Variance Account.

2.5 *NEW PPA WITH BC HYDRO AND ACCESS TO MARKET SAVINGS*

On May 24, 2013, BC Hydro filed an application for approval of the New PPA between BC Hydro and FBC that will replace the existing power purchase arrangement that expires September 30, 2013. The New PPA forms the basis of the forecast power purchase expense in this application from October 1, 2013 forward.

The power purchase arrangement with BC Hydro PPA continues to provide FBC with a firm and very reliable capacity and energy resource and is a valuable component of FBC's power supply portfolio. Under the 1993 PPA, the Company could take up to 200 MW in each hour at BC Hydro's embedded cost rates and there were no take or pay restrictions. On a planning basis, therefore, FBC was able to forecast its annual power purchase requirements based on meeting its energy and capacity requirements with its firm resources, including the supply available from BC Hydro under the 1993 PPA, prior to taking into account any market based mitigation activities. As there were no take or pay restrictions, FBC could subsequently capture market savings by replacing BC Hydro PPA supply with market purchases when and if favourable conditions arose. In the past few years, as the result of changes in the regional market environment that have created favourable pricing opportunities, this has resulted in a large difference between planned and actual purchases under the BC Hydro PPA.

Under the New PPA, FBC continues to have access to 200 MW of capacity in any hour, plus all the associated energy. However, the access to energy based on BC Hydro's embedded cost is limited to 1,041 GWh per annum. Above 1,041 GWh, the cost for the energy increases to BC Hydro's proxy for long run marginal cost. In addition, under the New PPA, FBC is required to submit an Annual Energy Nomination by June 30th of each year, for energy deliveries in the following October to September Contract Year and is required to take and pay for 75 percent of the Annual Energy Nomination. Any energy taken above the Annual Energy Nomination is priced at 150 percent of the base rate. In addition, year over year FBC cannot change its Annual Energy Nomination by more than 20 percent.

As a result of these changes, in order to optimize its power supply portfolio and to ensure firm resources are place to meet expected demand, the Company will need to undertake increased planning and forecasting of its energy requirement and future market prices in order to support the Annual Energy Nomination. When market conditions allow, this may include entering into term firm market supply contracts to lock in savings and to allow a lower Annual Energy Nomination and reduce the take or pay commitment under the New PPA. Any such contracts will need to be completed prior to the June 30th deadline for the upcoming contract year beginning October 1. These contracts will be then be accounted for in the power purchase expense forecast along with the corresponding changes in BC Hydro PPA purchases.

For the first year of the New PPA, October 1, 2013 to September 30, 2014, FBC forecasts an energy requirement of 973 GWh after using FBC's other firm resources. This will need to be supplied from the PPA with BC Hydro, from the spot market or contracted term market purchases. Current market conditions does allow FBC to enter into term contracts at prices lower than taking the full requirement under the BC Hydro PPA. In order to mitigate power purchase expenses during the first year of the PPA while ensuring a reliable source of supply, FBC expects to make an Annual Energy Nomination of 670 GWh and plans to enter into additional term market based energy supply contracts for 303 GWh of energy in order to meet the forecast energy requirement of 973 GWh. The Company has included this assumption in its 2014 power purchase expense forecast associated with BC Hydro PPA purchases and Market Purchases.

With an Annual Energy Nomination of 670 GWh, FBC will have a take or pay requirement of 503 GWh (i.e. 75 percent of 670 GWh) under the New PPA. The remaining 25 percent flexibility (168 GWh) will be used to meet variability in annual load requirements and to potentially further displace PPA energy in real time when market conditions are favourable. For the purposes of the 2014 Power Purchase Expense Forecast, FBC has estimated a further $2 Million reduction to BC Hydro expense based on current market forecasts. Depending on actual market prices as well as actual Company load, these further savings may or may not be realized.

For the second year of the PPA, October 1, 2014 to September 30, 2015, the maximum PPA nomination that the Company can make is 120 percent of the Year 1 nomination, equal to 804 GWh. The Company forecasts an energy requirement in Year 2 of 1,009 GWh, after using FBC's firm resources, excluding the PPA and market and contracted purchases. Therefore, the Company also plans to enter into a firm supply contract for 204 GWh for the winter of 2014/2015 in order to enable the 2013/2014 nomination. Prior to making the nomination for year 2, and for subsequent years, the Company will revaluate the cost of PPA energy compared to the cost of market energy, and will make a decision at that time. For this Application, the Company has assumed a BC Hydro PPA nomination of 700 GWh in Year 2, and has forecast market purchases of 309 GWh. The Company believes that this strategy minimizes the risk to the rate payer, by ensuring firm, fixed price resources over the planning horizon, while allowing the Company access to the market in order to mitigate power purchase expense.

2.6 *MARKET PRICE FORECAST METHODOLOGY*

The forecast market prices are based on a combination of published and non-published sources, including a May 13, 2013 Argus Media Publication titled "Argus US Electricity" and consultations with market participants. These sources are used to derive a monthly forecast market price for the heavy load hours (HLH). The hourly HLH forecast is used to estimate the cost of any peak demand shortfall. In order to get the energy from the MID-C to the FBC service territory, the Company applies a cost of $4 USD/MWh to the forecast Mid-C price as a transmission charge. The Company escalates this forecast based on quarterly and annual forecasts from the sources above, in order to extrapolate a 5 year market price forecast.

For market purchases required for capacity it is assumed that the Company will only be in the market for the peak hours of the month. FBC's peak hours for any month are usually the same peak hours as the rest of the Northwest Power Pool, which usually causes increased prices during these peak hours and peak days. Because of this, the Company anticipates that the block price for all heavy load hours will not accurately reflect the cost that the Company expects to pay for capacity to meet its peak demand. The Company adds a 20 percent premium to the block forecast of heavy load energy to account for the peak hour premium. Additionally, these forecasts are converted to Canadian dollars, based on the Company's forecast exchange rates.

2.7 *SURPLUS SALES*

The Company can have small amounts of surplus available in the months of May, June and July when its firm resources, including the entitlements under the CPA, exceed the load requirements in that period.

As a result of the one third sale of the Waneta Dam to BC Hydro, the Company entered into a five year deal with Powerex to sell its summer surplus energy. The Company expects to exercise this deal in July 2013 and July 2014, and currently forecasts 11 GWh in surplus sales for 2013, 22 GWh of surplus sales in 2014, compared to the 2012 actual amount of 0 GWh. In 2012 there were no surplus sales due to low market prices that remained throughout the summer.

Table **C2-6: Summer Surplus Sales ($ thousands)**

		2012 Actual	2013 Projection	2014 Forecast
1	Volume (GWh)	-	(11)	(22)

Overall the revenue from summer surplus sales is expected to increase to approximately $0.3 million and $0.6 million in 2013 and 2014 respectively.

2.8 *WHEELING EXPENSE*

This section provides a review of the Wheeling Expense including actuals from 2012, a year end projection for 2013 based on actual results to April 30, 2013, and a full year forecast for 2014. The expense includes wheeling service provided by BC Hydro Transmission under the General Wheeling Agreement (GWA) and Open Access Transmission Tariff (OATT), as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck for the use of its 71 Line. Rates under the GWA are specified in BC Hydro's Rate Schedule 21.

In 2013 and 2014, GWA costs are forecast to account for all of the wheeling expense, except for $0.05 million of OATT and Teck wheeling in both years.

Wheeling Expense is forecast to increase from $4.8 million in 2012 to $5.2 million in 2013 and 2014. The increase in 2013 is due to higher wheeling nominations in the Okanagan, increasing from 225 MW to 230 MW on October 1, 2013 to account for increased load growth in the region as well as a forecast rate increase on October 1, 2013 based on forecast CPI. The 2014 Wheeling Expense forecast remains constant from 2013 at $5.2 million as a result of a reduced Okanagan Wheeling nomination from 230 MW to 200 MW on October 1, 2014. This decrease is a result of the GWA nominations being made five years in advance, and the reduction in the Companies load forecast in 2009 compared to 2008, following the global economic downturn. The reduced cost for the Okanagan is offset by an increased Creston nomination from 35 MW to 36 MW beginning October 1, 2014 and continued annual rate increases based on CPI.

The calculation of Wheeling Expense for 2012, 2013, and 2014 is shown in the table below:

Table C2-7: Wheeling Expense

		2012 Actual	2013 Projection	2014 Forecast
1	**Wheeling Nomination**		**(MW)**	
2	Okanagan	2,475	2,715	2,670
3	Creston	420	420	423
4	Expense		**($000s)**	
5	Okanagan	4,211	4,680	4,691
6	Creston	466	472	485
7	Other	137	59	48
8	Total Wheeling Expense	4,813	5,210	5,224

2.9 *WATER FEES*

Water fees are assessed by the Province based on FBC's entitlement usage in the previous year and the rate increases are indexed to the CPI. Water fees are forecast to be down slightly in 2013 due to reduced plant entitlement use in 2012 caused by spill during the freshet because of low market power prices. Water fees increase in 2014 due to increasing plant entitlement use forecast for 2013, as well as the increase in water fee rates from 2013 levels based on the forecast CPI.

The calculation of Water Fees for 2012, 2013, and 2014 is shown in the table below:

Table C2-8: Water Fees ($ thousands)

		2012 Actual	2013 Projection	2014 Forecast
1	Plant Entitlement Use (GWH) in previous year	1,527	1,531	1,602
2	Water Fees ($000s)	9,253	9,387	10,057

The Company proposes to continue using a deferral account to collect the difference between actual and approved 2014 Water Fees as explained in Section D4.

2.10 *SUMMARY OF 2015 TO 2018*

The forecast of power purchase expense for 2015 through 2018 is shown in the table below:

Table C2-9: 2015 to 2018 Power Purchase Expense Forecast ($ thousands)

		2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Brilliant	38,336	39,151	39,983	40,835
2	BC Hydro	40,660	48,315	51,287	55,712
3	Waneta Expansion	25,864	41,960	42,594	43,597
4	Independent Power Producers	165	169	172	176
5	Market and Contracted Purchases	11,822	5,060	3,125	414
6	Surplus Sales Revenues	(467)	(451)	(446)	(411)
7	Special and Accounting Adjustments	-	-	-	-
8	Balancing Pool	-	-	-	-
9	TOTAL	116,380	134,204	136,716	140,322
10	Gross Load (GWh)	3,537	3,554	3,572	3,596

The forecast increase from $87.8 million in 2014 to $140.3 million in 2018 is a result of increased load and a greater reliance on BC Hydro energy and capacity, increases to the Brilliant rates, as well as the Waneta Expansion project forecast to come online on May 15, 2015. From 2015 to 2018, forward market prices are forecast to increase, resulting in fewer opportunities for market and contracted purchases. Furthermore, the 5 year contract with Columbia Power Corporation expires December 31, 2017, and the Company has not included a forecast renewal in these estimates. In addition, the BC Hydro costs are based on BC Hydro's approved rates as of April 1, 2013 throughout the period and do not include an estimate of future BC Hydro rate increases. The next BC Hydro rate increase is expected April 1, 2014.

With the Waneta Expansion project forecast to come online in 2015, the Company will not have a capacity deficit, and will have surplus capacity compared to its forecast peak load requirements which it will sell in order to mitigate power purchase expense. The estimate of this mitigation is included in line 3 in Table C2-9 above.

Due to the expiry of the 5 year contract with Columbia Power Corporation on December 31, 2017, the Company anticipates an energy shortfall of 9 GWh in 2018, as the energy purchased under the BC Hydro PPA, limited to 200 MW in each hour, cannot be increased any further over the winter. The Company currently forecasts meeting this energy shortfall with spot market purchases which has been included in the estimates above.

The forecast of Wheeling Expense and Water Fees for 2015 through 2018 is shown in Table C2-10 below.

Table C2-10: 2015 to 2018 Wheeling and Water Fees ($ thousands)

		2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Wheeling Fees	10,532	10,479	10,688	10,902
2	Water Fees	4,856	4,952	5,050	5,208

3. OTHER INCOME

3.1 *INTRODUCTION*

Other Income is revenue other than from the sale of electricity and is derived from the following sources:

Table C3-1: Other Income ($ thousands)

		Actual 2012	Approved 2013	Projected 2013	Forecast 2014
1	Apparatus and Facilities Rental	5,018	3,478	4,184	4,156
2	Contract Revenue	1,943	1,315	1,709	1,385
3	Miscellaneous Revenue	728	1,203	717	738
4	Transmission Access Revenue	1,454	1,071	1,247	1,224
5	Investment Income	104	98	90	78
6	**Total**	**9,247**	**7,165**	**7,947**	**7,582**

3.2 *APPARATUS AND FACILITIES RENTAL*

Apparatus Rental is primarily pole contact revenue from other utilities and businesses that attach their facilities to the FBC system in order to deliver services to their customers. Examples include telephone and cable television providers. Customers are charged a unit rate per pole contact multiplied by the number of poles that they have contacted. Periodic audits are conducted to verify the number of contacts on each pole and an audit is being conducted in 2013.

Annual billing is completed mid-year and estimates the number of pole contacts for each customer at year-end as well as FBC costs that are included in the rate per pole contact. The rate per pole contact is updated annually to reflect actual FBC costs. Any billing true-up that is required as a result changes to the rate or number of pole contacts at the end of the year is captured in the following year's billing. The forecast pole contact revenue for 2013 and 2014 includes the addition of City of Kelowna assets beginning in April 2013.

An increase in revenue following the annual true-up resulted in higher 2012 billings compared to 2013 Projected and 2014 Forecast.

A small percentage of revenue has been realized from subletting space in the Trail office building. FBC has exercised the Option to Purchase of the Lease Agreement for the Trail facility, which was approved by Order G-110-12. This action triggers a requirement from the Sublease Agreement for FBC to provide a Strata Lot to the School District sublease tenant which will result in them owning their space and will eliminate the rent payment.

3.3 *CONTRACT REVENUE*

The Company operates and maintains a number of facilities for third party entities. Transactions between FBC and its affiliated Non-Regulated Business (NRBs) are conducted in accordance with FBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP)[37]. A more comprehensive discussion on the applicability of COC and TPP is included in Section D3 Accounting Policy.

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third party work and the associated revenue fluctuate based on customer requirements, as can be seen in Table C3-1 above. For these contracts the anticipated work will peak in 2012 and decline in 2013 and 2014.

FortisBC Pacific Holdings Inc. (FPHI) revenue is the transfer price profit on third party contract work conducted by FBC on behalf of FPHI. The volume of work, and therefore the transfer price profit, fluctuates based on customer requirements. Revenue from FPHI decreased in 2013 as a result of FBC's acquisition of the utility assets of the City of Kelowna, and the expiration of the City's contract with FPHI.

FBC also performs services for FPHI in regard to the Waneta Expansion (WAX) plant. Transfer price profit revenue derived from FPHI for project planning and oversight of WAX has been included in projected 2013 and forecast 2014 contract revenue. Beginning in 2015 the transfer price profit revenue from FPHI will include ongoing operating and maintenance for the WAX plant once in service.

3.4 *MISCELLANEOUS REVENUE*

Miscellaneous Revenue is made up of Connection Fees, Non-sufficient funds (NSF) charges and Sundry Revenue. Lower than forecast customer growth in 2013 resulted in a decrease to Connection Fees, compared to Approved. The majority of the sundry revenue is a recovery of costs for service such as street light maintenance charged to municipalities.

3.5 *TRANSMISSION ACCESS REVENUE*

Transmission Access Revenue represents charges to customers who utilize FBC's transmission system to transmit power over the FBC system. Two customers are forecast to be using the transmission system in 2014, and are expected to generate an estimated combined revenue of $1.2 million in 2014. The revenue projected for 2013 has increased from the 2012-2013 RRA forecast as a result of an increase to interim wheeling rate charged to one customer when the final rate was calculated.

[37] As approved by Order G-5-10A.

3.6 *INVESTMENT INCOME*

Investment income is primarily DSM loan interest income and foreign exchange gains or losses. The Company is experiencing a decline in the number of DSM loans. Hence, as loans mature a corresponding drop in interest income is expected.

3.7 *SUMMARY OF 2015 TO 2018*

FBC is forecasting only modest growth in Other Income over the PBR Period. Other Income will be reforecast each year at the Annual Review for rate setting purposes.

Table C3-2: 2015 to 2018 Other Income ($ thousands)

	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1 Other Income	7,360	7,781	7,755	7,819

3.8 *SUMMARY*

Other Income is forecast to be 365,000 lower in 2014, compared to 2013 Projected, due to reduced Contract Revenues. This reduction results primarily from the expiration of FBC's subcontract with FPHI for the City of Kelowna and from lower Brilliant management fees, which fluctuates from year to year. Other Income will be reforecast annually and updated as part of FBC's RRA filings and Annual Reviews during the PBR period.

4. OPERATIONS AND MAINTENANCE (O&M) EXPENSE

4.1 *INTRODUCTION AND OVERVIEW*

This section provides both historical and forecast O&M for FBC 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. FBC has also adjusted the 2013 O&M Projection to the 2013 O&M Base for PBR purposes, which is forward looking.

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 FBC. 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.

4.1.1 Department Overview

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

- Section C4.4: Generation
- Section C4.5: Operations (Transmission and Distribution Network Services)
- Section C4.6: Customer Service
- Section C4.7: Communications and External Relations
- Section C4.8: Energy Supply
- Section C4.9: Information Systems
- Section C4.10: Engineering Services
- Section C4.11: Operations Support
- Section C4.12: Facilities
- Section C4.13: Environment, Health and Safety
- Section C4.14: Finance and Regulatory Services
- Section C4.15: Human Resources

- Section C4.16: Governance
- Section C4.17: Corporate
- Section C4.18: Advanced Metering Infrastructure Impact

4.2 HISTORICAL O&M BY DEPARTMENT

Summary O&M by department for the years 2010 through 2013 is shown below in Table C4-1.

Table C4-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Generation	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492
Operations	$ 14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	$ 5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	$ 1,639	1,469	1,244	1,431	1,440	1,469
Energy Supply	$ 827	893	986	1,069	1,124	1,124
Information Technology	$ 2,929	2,903	2,925	2,841	2,988	2,974
Engineering	$ 1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	$ 993	1,315	1,240	1,223	1,205	1,252
Facilities	$ 3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	$ 727	867	894	925	953	953
Finance & Regulatory	$ 3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	$ 1,638	1,747	1,816	1,840	1,874	1,874
Governance	$ 2,284	2,031	2,134	1,792	2,490	2,373
Corporate	$ 3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	$ -	-	-		-	-
Total O&M	**$ 46,149**	**$ 53,075**	**$ 53,544**	**$ 54,843**	**$ 57,169**	**$ 57,621**

The table above illustrates the extent of cost pressures on FBC's O&M in recent years. The more significant cost items that have increased O&M beginning in 2011 are the reclassification of certain expenditures previously recorded in capital, as ordered by the Commission by way of Order G-195-10 (an increase of $4.0 million in 2013), and the costs associated with the BC Mandatory Reliability Standards Program ($1.2 million in 2013). Nevertheless, after accounting for these items along with Pension and Trail Office lease costs, O&M per customer, on an inflation-adjusted basis, is projected to be more than four percent lower in 2013 compared to 2010, a result which is partly attributable to economies of scale realized from the addition of the approximately 14,500 customers from the City of Kelowna.

While 2012 O&M was approximately $1.3 million lower than the approved amount, resulting from certain expenditures being postponed pending an RRA decision that was issued in August of that year, 2013 O&M is projected to be within 1.0 percent of approved. The 2013 O&M savings of approximately $452 thousand is being flowed through to the 2013 O&M Base which is used to determine the amount of O&M for the 2014 – 2018 PBR Period, and results in a sustainable benefit to customers.

4.3 *2014-2018 FORECAST O&M OVERVIEW*

4.3.1 2013 Base O&M

In Section B6.2.4 of the Application, FBC has reconciled the 2013 Approved to the 2013 Base used for setting rates under FBC's PBR Plan. In that section, FBC 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 C4-2.

Table C4-2: Determination of Base O&M by Department ($ thousands)

	2013 Approved	Productivity (Sustainable Savings)	2013 Projection	2013 Deferrals			Incremental O&M	2013 Base
				PST	Pension	MRS		
Generation	2,492	64	2,556	3	137		350	3,046
Operations	20,816	122	20,938	53	769			21,760
Customer Service	7,541	(31)	7,510	15	333			7,858
Communications & External Relations	1,469	(29)	1,440	14	35			1,489
Energy Supply	1,124	-	1,124	2	52			1,178
Information Technology	2,974	14	2,988	36	124			3,148
Engineering and Project Management	2,791	31	2,822	5	141	900		3,868
Operations Support	1,252	(47)	1,205	2	51			1,258
Facilities	3,466	(77)	3,389	16	30		(909)	2,526
Environment, Health & Safety	953	-	953	1	59			1,013
Finance & Regulatory	4,271	(191)	4,080	6	201			4,287
Human Resources	1,874	-	1,874	4	80			1,958
Governance	2,373	117	2,490	10	31			2,531
Corporate	4,225	(425)	3,800	11	115			3,926
Total O&M	**57,621**	**(452)**	**57,169**	**180**	**2,158**	**900**	**(559)**	**59,848**

4.3.2 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 funding requests are driven by five broad based business drivers: (i) labour inflation and benefits, (ii) customer focus, (iii) productivity, (iv) demographics, and (v) system reliability and safety. Each driver is described below.

4.3.3 Labour Inflation and Benefits

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

- Executives;
- Management and Exempt (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 the same 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.

4.3.3.1 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 incentive to encourage and reward performance.

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

1. base pay;
2. short term incentive pay;
3. long term incentive pay; and
4. benefits.

All of these elements support the needs of the business and its customers, and contributes 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 on-going 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. FBC provides its long term incentive through participation in Fortis Inc. stock based plans[38]. The stock option is funded by the shareholder and is not included in revenue requirements.

Pursuant to Order G-110-12, FBC commissioned a study containing benchmarking information on its executive compensation. The study, contained in Appendix C2 which has been filed in confidence with the Commission, concludes that for FBC's executive, base salary and target total cash are generally positioned around market median, but a loss of competitiveness is evident at target total direct level, primarily due to weakness in the long term incentive component of compensation.

Appendix C3 Incentive Compensation in Pensions addresses directive 15 on page 59 and 151 of the 2012-2103 RRA Decision, regarding the inclusion of incentive payments in pensionable earnings with reference to a peer group of companies. FortisBC's current pension practice of including incentive pay as pensionable, mirrors the treatment of incentive earnings in pensions, practiced by the majority of companies in FortisBC's peer reference group and more specifically is the practice in the regulated utility industry.

4.3.3.2 M&E Employees

As a general policy, FBC 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. FBC 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. 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.

[38] Stock based compensation includes stock options and Performance Share Units (PSUs) with both expensed to the shareholder.

4.3.3.3 Unionized Employees

FBC 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 pension plan and COPE pension plan are jointly trusted, cost-shared defined benefit pension plans. FBC has made considerable progress in negotiating harmonized benefit plans (as are in place for its M&E employees) for active COPE employees.

4.3.3.4 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. Employee labour and benefit costs are calculated and expressed as a percentage of hours worked; thus benefit-loaded labour costs are allocated between O&M and capital, based on the chargeable hours forecast against O&M and capital activities. In 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 C5.

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

4.3.3.4.1 LABOUR INFLATION

[redacted]

4.3.3.4.2 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.

The actual 2013 Pension and OPEB expense of approximately $13 million has been allocated between 2013 Base capital and O&M. Forecast pension and OPEB expenses are based upon actuarial estimates provided by the Company's third party actuary, Towers Watson. The Pension and OPEB expense for 2013 Base and the 2014-2018 Forecast, as well as the allocation between O&M and Capital are included in Table C4-3 below.

Table C4-3: Pension and OPEB Capital and O&M Forecasts ($thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Pension & OPEB expense	12,962	12,299	11,445	10,591	9,870	9,280
Pension & OPEB expense allocated to capital	6,740	6,395	5,951	5,507	5,132	4,825
Pension & OPEB expense allocated to O&M	6,222	5,904	5,494	5,084	4,738	4,454

Pension and OPEB expense has been and will continue to be a significant challenge in managing increases in costs for FBC. For 2013, the actuarial estimate that was recently completed is approximately 70 percent higher than the actuarial estimate that was completed in 2011 to establish the 2012-2013 RRA forecasts and approved amounts. This increase is primarily due to the low interest rate environment and poorer than expected returns on pension plan assets. The difference between the actual and approved 2013 pension and OPEB expense has been accumulated in a deferral account which was approved pursuant to Order G-110-12. The recovery period for this deferral account balance has been requested for recovery from customers in future rates over a term of 11 years as described in section D4.

In this Application, FBC has forecast Pension and OPEB expenses for 2013 through 2018. The 2015 through 2018 forecast amounts demonstrate the expected trends over the PBR Period. As Pension and OPEB expenses are tracked outside of the PBR formula, they will be reforecast yearly as part of the Annual Review process.

4.3.4 Customer Focus

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, 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. FBC 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.

4.3.5 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 Gas business. Department O&M requirements over the PBR period have been developed with this productivity challenge in mind. Future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome challenges around union issues and IT platforms and differences in the nature of the electric and gas operations.

4.3.6 Demographics

Continued focus will be required to recruit, develop, transition, and manage overall changes to the composition of FBC's workforce in the coming years. An FBC five year workforce plan was submitted to the BCUC on December 1, 2012. This section is consistent with the 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.

FBC in-demand skill positions which require focus are:

- Mid-Level Managers
- Engineers
- Power Line Technicians
- Communication Protection & Control Technicians
- Power System Dispatchers
- SAP Information Technology Roles

FBC'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.

4.3.6.1 Workforce Planning

FBC 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.

The Human Resources department 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.

4.3.6.2 Targeted Recruitment

To hire difficult to fill and in-demand skill positions FBC 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. Developing awareness of high school students about careers within the utility sector through the Bright Futures program.

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

4.3.6.3 Developing Internal Talent

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

4.3.6.3.1 LEADERSHIP DEVELOPMENT

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

Delivery of Targeted Development Programs - 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 range 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.

4.3.6.3.2 TECHNICAL TRADES AND ENGINEERING

Engineering and trades development programs remain a priority.

Technical Trades: FBC provides field-based training that supplements the red seal trades for Power Line Technicians (PLT), and Communication, Protection and Control (CPC) Technologists. The Company supports apprenticeship programs for PLTs to meet the need for trained and qualified tradesmen. These programs include in-house training, external training and on-the-job experience. Apprenticeship selection is based on resource plan requirements in the business areas.

Engineering: 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 EITs work towards accreditation as professional engineers and to expedite their development in the gas utility industry.

4.3.6.4 Conclusion

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. FBC believes the actions and activities described above appropriately address the demographic realities and position the Company to continue to deliver on the commitment to customers to provide safe, reliable and cost effective service.

4.3.7 Sharing of Services with FEI

Throughout the following discussion on the Company's O&M, there are references to sharing of common resources between FBC and FEI, as well as FBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP) with Non-Regulated Business (NRBs). A more comprehensive discussion on the sharing allocation methodology and the applicability of COC and TPP is included in Section D3 Accounting Policy.

4.4 *GENERATION*

4.4.1 Description of Generation Department

The Generation department at FBC manages, operates and maintains the Company's four generating stations along the Kootenay River, forming an integral part of the power supply system. These facilities include the Lower Bonnington Dam which was originally constructed in 1897 and upgraded in 1924, the Upper Bonnington Dam constructed in 1907 and extended to incorporate an additional two units in 1940, the South Slocan Dam constructed in 1924 and the Corra Linn Dam which was constructed in 1932. In total, there are 15 units ranging in size from 5 MW to 23 MW with an entitlement[39] capacity of 221 MW and a yearly entitlement of 1,611 GWh.

In addition to the operations and maintenance of these four facilities, the department also manages under various contracts, an additional 950 MW of generation in four additional facilities owned by third parties. Where the provision of services for these contracts is performed for a non-regulated affiliate, the services are governed by the COC and TPP, which were reviewed and approved by the Commission via Order G-5-10A.

The department employs approximately 100 employees annually comprised of approximately 65 full time and 30-35 temporary employees, depending on the type of work and the timing of such work. In addition to skilled trades, the full time employees in the Generation department include management, engineering, planning, project management and safety and environment staff.

4.4.2 Business Drivers for Generation Department

With the recent completion of the Upgrade and Life Extension (ULE) program the Generation department focus shifts back to operation and maintenance of the units. To ensure continued reliable operation of the river plants, inspections, testing and maintenance activities must be performed on a frequent basis. Currently most of these activities are routine and conducted on an annual or bi-annual basis, as specified by the Original Equipment Manufacturer (OEM). The issues the department will face as it moves into 2014 and beyond are:

[39] Entitlement capacity and energy are determined according to the Canal Plant Agreement.

1. With the completion of the ULE program, the Company will return to its full maintenance program at the facilities comprised of both routine (1 to 2 year intervals) and non-routine (3, 5, 10, 15 year intervals) tasks. This program will be guided by a condition-based philosophy rather than a time-based interval philosophy. The effect would be a change in the interval between both routine and non-routine maintenance based on condition of the equipment, risk of failure, and priority to operations.

2. The last major unit overhaul completed at Generation was prior to the commencement of the ULE program in 1998. Surveys by Centre for Energy Advancement through Technological Innovation (CEATI) of utility best maintenance practices indicate that major electrical inspection is required after 10 years of continuous operation (generally taken to be 8,000 hours per year) and major mechanical inspection typically every 20-30 years. The electrical inspections consists of an in-depth inspection and include activities such as removal of the rotor, cleaning of the rotor and stator, thorough electrical inspection and mechanical and electrical component maintenance which are only possible when the rotor has been removed. Other non-routine activities include turbine cavitation welding, hoist overhauls and auxiliary component overhauls.

3. Ensuring compliance with the changing Dam Safety legislation continues to be a priority for FBC. For example, dam safety inspections are required to be conducted at each plant classified as Extreme every 7 years and 10 years for each plant classified as High/Very-High, to ensure compliance with BC Dam Safety Regulation 44/2000 including amendments up to BC Reg 163/2011, September 12, 2011 (BCDSR). As a result of the recent changes, Corra Linn plant is now classified as Extreme and inspections must be done every 7 years.

4. Within the reach of the Kootenay River, where the Company-owned hydro facilities are located, there are two species of fish which could potentially be listed under Schedule 1 of the Species at Risk Act (Umatilla Dace and Shorthead Sculpin). Presently, Umatilla Dace is listed as “Special Concern”, but the listing is under review and it may be up-listed to “Threatened”. The Shorthead Sculpin is presently listed as “Threatened”, but this listing is under review and is recommended for down-listing to “Special Concern”. Species listed on Schedule 1 of SARA are subject to the prohibitions of the Act which states that a person shall not kill, harm, harass, capture or take an individual of a wildlife species that is listed as an extirpated, endangered or threatened.

5. The operating impact of listing of a species as threatened has been seen at third party facilities managed by the department, where the associated monitoring studies, mitigation measures and changes to operating procedures resulted in increased operating costs at these facilities. Currently the Generation department’s annual budget includes only a small allocation for monitoring but there is the potential this could have an impact on operating cost.

6. Changes to Workplace Health and Safety requirements – Recent changes to legislation targeted at improving workplace safety have had an impact on operating costs over the past five years. For instance, the recognition of silica dust (from concrete coring, drilling, etc.) has resulted in the requirement for new equipment and additional time added to routine type work to manage the risks associated with this substance. As new information becomes available, legislation and accepted practices evolve, FBC is committed to ensuring a safe work environment. There is the potential that these changes can have an impact on operating costs.

4.4.3 Generation Review

Generation O&M expense consists of the costs to operate and maintain the equipment at each of the four generating plants. The largest percentage of this expense is labour and contracted labour. This cost has remained fairly constant over the past three years. Changes in labour costs are attributable to annual salary increases, the extent of third party work and maintaining a consistent workforce. Annual variation in O&M non-labour is generally attributable to scope of work for non-routine work.

Table C4-4 below shows a summary of the Generation department's O&M costs for the years 2010 through 2013.

Table C4-4: Generation O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,600	$ 1,703	$ 1,854	$ 1,887	$ 1,916	$ 2,357
Non-Labour	617	696	477	605	640	689
Total O&M	**$ 2,217**	**$ 2,399**	**$ 2,331**	**$ 2,492**	**$ 2,556**	**$ 3,046**

Generation O&M expenses are subject to a relatively small degree of fluctuation from year to year, as required to respond to varying requirements of its third party contracts. FBC nevertheless ensures that its focus remains on the priority requirements for FBC's assets, in line with a condition-based approach to maintenance.

The increase in non-labour expenses was primarily due to legislative changes. For example, new dam safety regulations were introduced in September, 2011 (BCDSR), increasing the frequency of dam safety reviews.

While the ULE program was in progress, the operating labour required to maintain the Company's plants fluctuated primarily due to inspections and corrective maintenance work. With the completion of the ULE and a focus on operations and maintenance activities to sustain existing reliability levels the labour cost will stabilize because the work is repetitive in nature from year to year.

In 2013 projected costs are estimated to be slightly higher than Approved to accommodate additional crane inspections, maintenance and documentation to be in compliance with WorkSafeBC requirements.

4.4.4 Generation Forecast

Generation will utilize a combination of routine maintenance, non-routine maintenance and capital investment as part of the maintenance and upgrade strategy for the river plants. The routine maintenance schedule, on an annual and bi-annual basis, includes tasks such as inspections, testing, monitoring and other routine maintenance. In addition, other non-routine maintenance tasks such as runner welds and regulatory requirements for Dam Safety and Mandatory Reliability are also being completed under the current budget. Table C4-5 below shows a summary of the Generation department's O&M costs for the years 2014 through 2018:

Table C4-5: Generation O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 2,427	$ 2,500	$ 2,575	$ 2,652	$ 2,732
Non-Labour	703	717	732	746	761
Total O&M	**$ 3,130**	**$ 3,217**	**$ 3,307**	**$ 3,398**	**$ 3,493**

Preventive maintenance is defined as actions performed on a time- or machine-run-based schedule that detect, preclude, or mitigate degradation of a component or system with the aim of sustaining or extending its useful life through controlling degradation to an acceptable level. Most of the preventative maintenance at the river plants is routine in nature and completed on an annual or bi-annual basis. However, if the maintenance cycle of equipment is defined based purely on operating hours it does not take into account the actual loading or condition of the equipment. Running a unit at partial load over an extended period of time, for example, means that there will be additional stresses on the equipment from rough load zone and cavitation, along with operation that is far from the unit's peak efficiency. As an example, based on the current operating times, the annual inspections have revealed a need for runner weld repairs to deal with cavitation issues on an average every 7 years. Essentially, the Company continues to refine its maintenance program through the development of a more condition-based maintenance approach but being aware of Industry best practices which suggest that equipment must be properly maintained to minimize the likelihood of an in-service failure.

In addition, a non-continuously operated unit is exposed to the most extreme operating conditions of all hydro units: the start/stop cycle. In 2012 there was an increase in the number of start/stop requests from BC Hydro to maximize water on the Kootenay River. Excessive start/stops can cause low cycle fatigue loading which can lead to cracking and subsequent failure. It is likely that the increased start/stops requests seen in 2012 could have an impact on future reliability and maintenance costs but to what extent is unknown.

Since the initiation of the ULE program no major overhauls were completed on any of the units. The cumulative operating hours and years since completion of the ULE on the unit is shown in Table C4-6 below.

Table C4-6: Operating Hours of Generating Units

Unit	Hours since ULE	Years since ULE
Lower Bonnington - 1	50,810	6.7
Lower Bonnington - 2	87,479	14.5
Lower Bonnington - 3	34,121	5.5
Upper Bonnington - 5	49,678	8.8
Upper Bonnington - 6	32,782	8.0
South Slocan - 1	17,874	2.9
South Slocan - 2	12,830	2.1
South Slocan - 3	26,925	4.0
Corra Linn - 1	14,999	1.9
Corra Linn - 2	7,872	1.1
Corra Linn - 3	66,336	12.9

Industry best maintenance practice suggests the major electrical inspection cycle is typically 10 years or 80,000 hours. With an annual average operating factor of 0.72 for a unit, this translates to a 13-year inspection cycle. Considering that the old units at Upper Bonnington have a lower annual factor of approximately 0.3, on an overall basis this translates to an average of a 15-year cycle for the 15 units. Therefore, the Generation department will schedule a Major Unit Inspection in each of the next 15 years. The actual schedule will be guided by condition, risk and operational priority. The Generation department estimates the annual cost of Major Unit Inspections at $350,000.

While some of the non-routine work is pre-determined based on regulatory requirements, should the annual inspection point to an impending maintenance need some of the other non-routine items that are not part of a regulatory requirement will be timed to deal with any higher priority item(s) identified in a given year.

4.4.5 Generation Summary

Despite identified budget pressures over the PBR Period, Generation has mitigated incremental funding forecasts to the extent possible. The expenditures are the minimum required to ensure that FBC's plants are maintained according to OEM guidelines and that all regulatory requirements are met.

4.5 *OPERATIONS*

4.5.1 Description of Operations Department

The FBC Operations department is responsible for the safe and reliable delivery of electricity to customers. The business area's primary responsibility is to safely keep the lights on. Activities include:

- Providing first response to system damage in order to ensure public, asset and employee safety.
- Monitoring and control of the transmission and distribution system by the System Control Centre (SCC);
- Participation in inter-utility technical groups such as the Western Electricity Coordinating Council (WECC); the Northwest Power Pool (NWPP) and the Centre for Energy Advancement through Technical Innovations (CEATI);
- Predictive and corrective maintenance of substations;
- Patrolling the transmission and distribution lines;
- Performing minor maintenance and responding to outages on transmission and distribution lines;
- Vegetation management along distribution and transmission right of ways;
- Connecting/reconnecting customers (not requiring capital construction); and
- Administration of the facilities sharing agreement between Teck Cominco and FBC and the long-term lease of the Brilliant Terminal Station.

4.5.2 Business Drivers for Operations Department

4.5.2.1 Resourcing

The electric operations group continues to face the challenge of an aging workforce in the utility trades, as was described at length in the Company's 2012-2013 RRA. The operations group continues to actively try to recruit skilled workers into these positions and in 2012, 6 new apprentice PLTs were recruited to help assist in the long term resource plan.

4.5.2.2 Line Maintenance

Upgrades of both the transmission and distribution network that have been completed over the last five years along with proposed upgrades as outlined in the 2012 Long Term Capital Plan will mitigate upward cost pressures over time. The upgrades will also help improve customer reliability and reduce safety concerns.

4.5.2.3 Vegetation Management

Brushing is a significant component of transmission and distribution line maintenance expenditures. FBC takes an integrated approach to minimize costs, maximize reliability and reduce public safety hazards. The Company continues to improve its vegetation management program, focusing on controlling tree growth under or near power lines to ensure adequate clearances. This minimizes public and worker safety hazards, tree-related fires and the occurrence of customer outages. Regular surveys are conducted to determine the physical location of hazard trees and general brush clearance locations. Wherever possible, vegetation that could grow or fall into FBC lines is removed or, where removal is not possible, problem vegetation is dealt with using proven arboricultural methods. The Company adapts its brushing program annually with consideration of cycle times, seasonal weather anomalies (fire season) and permit requirements.

4.5.2.4 Substation Maintenance

Substations contain power transformers, breakers and ancillary equipment that control the supply of electricity to customers. This equipment is energized at high voltages, so safety measures to protect the public and workers are essential. Substation expenses include the costs of the operation and maintenance of the Company's substations, including the cost of materials and supplies incurred in connection with the inspection and maintenance of substation equipment.

4.5.2.5 Teck Facility Charge

The Facilities Sharing Agreement between Teck Metals Ltd. (Teck, formerly Teck Cominco) and FBC provides for the shared use of Teck facilities. This Agreement was originally approved by Commission Order E-7-96.

4.5.2.6 Brilliant Terminal Station:

In 2003, the Company entered into a long-term lease of the Brilliant Terminal Station (BTS) which the Commission approved for recovery in rates as an operating lease pursuant to Order G-2-04.

4.5.3 Operations Review

Table C4-7 below sets out the historical O&M for Operations. The 2013 projection is in line with the 2013 Approved, with only a small 0.6% increase.

Table C4-7: Operations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 8,668	$ 9,532	$ 10,060	$ 10,812	$ 10,794	$ 11,564
Non-Labour	6,223	9,072	9,670	10,004	10,144	10,196
Total O&M	**$ 14,892**	**$ 18,604**	**$ 19,730**	**$ 20,816**	**$ 20,938**	**$ 21,760**

The table above shows the increase in 2011 resulting from the Commission's decision on the Company's 2011 Capital Expenditure Program (Order G-195-10) directing that certain capital expenditures (totalling $3.78 million) were more appropriately classified as operating expenses. This reclassification affected both labour and non-labour resources.

Also included in Table C4-8 (2013 Projection and 2013 Approved) is an increase in O&M Expense of $0.49 million, reflecting the increased expense associated with the assets purchased from the City of Kelowna, effective March 31. The 2013 Base reflects the full year impact of these costs going forward.

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 gas utility. There is only a small portion of field employees in the overlapping gas service territory and they are primarily skilled in working with and around electric transmission, distribution and stations infrastructure. The field workforces also work with two very different products (gas versus electricity) and as such require different certifications, education and skill sets. In areas of work where there are similar skill sets required, Operations will drive toward achieving synergies and cost effectiveness through integration and adoption of best practices.

4.5.4 Operations Forecast

Table C4-8 below sets out the 2013 Base and the high level 2014-2018 operating and maintenance forecasts for Operations. The forecast represents the scope of work that is anticipated for the PBR Period. The 2013 Base has been adjusted to include O&M work associated with the City of Kelowna electrical assets that were acquired by FBC on March 28, 2013.

Table C4-8: Operations O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 12,028	$ 12,388	$ 12,760	$ 13,143	$ 13,537
Non-Labour	10,543	10,658	10,849	11,041	11,238
Total O&M	**$ 22,571**	**$ 23,046**	**$ 23,609**	**$ 24,184**	**$ 24,775**

Operations are not forecasting any incremental labour or non-labour increases other than inflation. Any additional changes in the scope of operations activities that drive incremental costs will need to be offset with productivity realizations.

4.5.5 Operations Summary

In conclusion, Operations is committed to delivering electricity safely, reliably and cost effectively to all customers. The forecast reflects the scope of work that is anticipated for the PBR Period. Any additional cost pressures, including changes in the scope of Operations activities or inflationary increases above those currently forecast will drive incremental costs that the Company will need to offset with productivity realizations.

4.6 CUSTOMER SERVICE

4.6.1 Description of Customer Service Department

The Customer Service department is responsible for providing accurate and timely billing for FBC's 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. Customer service manages the PowerSense demand-side management programs that help customers conserve energy. Revenue protection activities, which are primarily focused on reducing electricity theft and managing pole sharing agreements, are also part of Customer Service.

4.6.2 Business Drivers for Customer Service Department

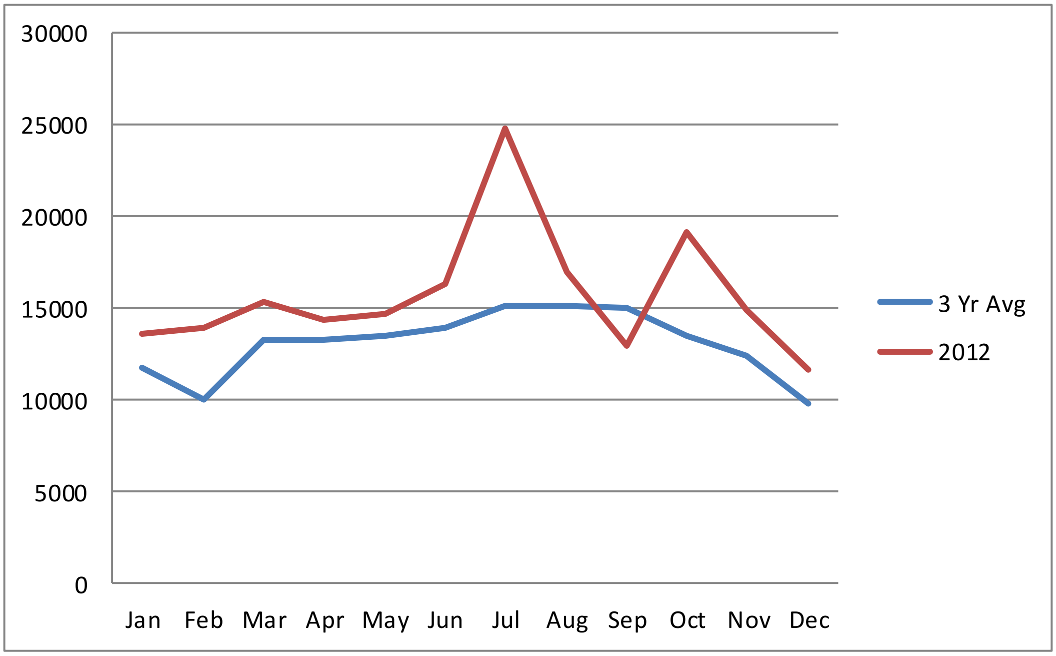
4.6.2.1 Contact Centers

The Contact Center in Trail, BC is staffed to ensure customer inquiries are handled by skilled and knowledgeable staff and in a timely manner. The main driver for costs is labour. Staffing levels in the contact center operations are impacted primarily by call volumes, both inbound and outbound.

4.6.2.1.1 CALL VOLUMES

Actual inbound call volume for 2012 was higher the 3 year average as can be seen in Figure C4-1 below. The Trail Contact Centers received a total of 188,630 inbound calls during 2012.

Figure C4-1: 2012 Inbound Call Volumes



Large outages in July and October are partially responsible for the call spikes shown above. A number of factors have contributed to a generally higher call volume in 2012 as compared to the three-year average such as an increased number of customers, LiveSmart calls, rate increases, rebate program, and the new Residential Conservation Rate have also impacted call volumes. Despite these pressures, FBC was able to keep labour costs lower than they were in 2012.

Forecast call volumes for 2014 to 2018 are expected to be higher than in 2012 due to the addition of City of Kelowna customers once they are transitioned to FBC's billing system and handled entirely by the Trail Call Center as of January 2014. AMI implementation is also expected to increase call volumes until 2016, and then decline as the project benefits come to fruition. Other seasonal variances due to weather patterns, variability in electric rates and general economic conditions may occur.

4.6.2.1.2 SELF-SERVE TRANSACTIONS

FBC does not currently provide online account access to customers (although there are some on-line self-serve options) nor are Interactive Voice Response (IVR) account transactions available to customers. However the Company is currently evaluating plans to introduce more options for customers in the future. Once in place, self-serve options will reduce the cost of customer interactions, while at the same time providing customers with choice regarding how they interact with the Company. In addition, following the implementation of AMI, customers will have in-home or on-line access to much more detailed electricity consumption information.

4.6.2.1.3 BAD DEBT EXPENSE

The bad debt expense will be managed by the Credit and Collections group. The forecast estimate of $630 thousand annually for 2013, and for the 2014-2018 period is based on historical write-offs and recoveries as well as an estimated amount of monthly billed revenue for all rates. An aggregate of the historical percentage of write-offs and recoveries is ultimately used to calculate the approximate percentage of write-offs and recoveries for the following year. In addition, Management may also take into account improvements to Collections practices and forecast economic conditions and, based on these, make some manual adjustments.

4.6.2.2 Billing Operations

The Billing Operations group is responsible for providing accurate and timely billing for FBC's 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. Future costs will also be impacted by customer uptake of paperless bill options (forecast at 21 percent for 2013).

4.6.2.3 Meter Reading Services

FBC's meter reading services are managed and delivered by internal staff. Residential and small commercial customer meters are generally read once every two months to obtain actual meter readings. Larger customer meters are generally read on a monthly basis. Customers on monthly or Equal Payment Plan (EPP) billing are billed based on an estimated read every other month.

The number of meters read is one of FBC's largest cost drivers. The total number of meters read in 2012 was approximately 722,000.

4.6.3 Customer Service Review

Revenue protection activities totalling approximately $200 thousand are included in the 2012 Actual and 2013 Projected and Approved expenses, pursuant to Commission Order G-110-12, but not in previous years. These expenses are comprised of approximately $100 thousand in labour expenses and $100 thousand in non-labour (contract) expenses. In addition, 2013 Projected and Approved expenditures include $835 thousand in costs related to customer service costs for the City of Kelowna customers.

Table C4-9: Customer Service O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 4,329	$ 4,725	$ 4,716	$ 4,830	$ 4,669	$ 5,002
Non-Labour	1,646	1,673	2,050	2,711	2,841	2,856
Total O&M	**$ 5,975**	**$ 6,398**	**$ 6,766**	**$ 7,541**	**$ 7,510**	**$ 7,858**

Normalizing the total 2013 forecast expenditures to $6,475 thousand by excluding revenue protection and City of Kelowna costs of $1,035 thousand results in a compound annual increase of 2.7 percent since 2010.

These inflation rates compare favourably with historic increases in labour and non-labour costs. Customer growth of 0.9 percent has also occurred over this period, putting further pressure on customer service O&M.

Customer service has been able to keep O&M cost increases low (in fact lower than the 2013 approved amount, which was itself reduced by $100 thousand from the amount requested by the Company) through a number of initiatives:

- Continued promotion of eBilling, reducing postage and printing costs;
- Improved collections processes and reduced write-off period resulting in stable bad debt costs; and
- Improved utilization of the Customer Service Representatives for third-party and PowerSense work.

4.6.4 Customer Service Forecast

The forecast O&M for the Customer Service department for 2014 – 2018 is shown in Table C4-10 below.

Table C4-10: Customer Service O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 5,399	$ 5,561	$ 5,727	$ 5,898	$ 6,075
Non-Labour	2,177	2,227	2,276	2,322	2,369
Total O&M	**$ 7,576**	**$ 7,788**	**$ 8,003**	**$ 8,220**	**$ 8,444**

Customer service costs will continue to be pressured by customer growth and inflation. The primary way in which these challenges will be addressed is by reducing the cost of customer interactions by leveraging technology and providing customers with the option of using lower-cost channels. For example, the Company will promote the increased use of its eBilling service which is less expensive for FBC and in many cases more convenient for the customer. Web and mobile-based self-serve options will also be expanded as described earlier in this document, reducing the cost of customer interactions and providing customers with choice regarding how they interact with the Company.

4.6.5 Customer Service Summary

Customer Service will continue to provide high-quality, cost-effective billing, demand-side management and support services throughout the test period. In addition, FBC will introduce new channels for customer interactions with the Company, providing customers with more choice and further improving efficiency

4.7 *COMMUNICATIONS AND EXTERNAL RELATIONS*

4.7.1 Description of Communications and External Relations Department

This department is comprised of two functional areas – Communications and External Relations. The detailed roles and responsibilities of each of these areas are described below.

4.7.1.1 Communications

This group is responsible for the development and execution of both internal and external communications. This entails responsibility for managing all customer, stakeholder and employee communications, including public safety education, bill inserts and media inquiries. Activities involve communications related to new projects, safety education, power outage management, emergency situations, operations and maintenance activities, rates and regulatory initiatives, and energy efficiency programs.

~~4.7.1.2~~ External Affairs

The External Relations group is responsible for building and fostering relationships with communities, First Nations, key government ministries and business associations to engage these key stakeholders in the company's various projects and initiatives. Such relationships are critical in supporting FBC's ability to move projects and programs forward in a timely manner to the benefit of its customers. These relationships are essential to the company's success as these stakeholders play a major role in governing and/or regulating the energy industry and the external environment in which the company operates.

The activities performed by these two groups are vital in furthering the company's projects, programs and initiatives by ensuring engagement of key stakeholders early on in the project cycle. For example, large projects and infrastructure upgrades require consultation and collaboration with the local communities served and affected to enable the company to meet the expectations of its customers and the community at large. This in turn facilitates the long term viability and timely completion of such projects. Additionally, the on-going communications to customers and the community at large provide a means for customers and stakeholders to stay informed of rate changes, new projects, programs, initiatives and proposals.

4.7.2 Business Drivers for Communications and External Relations Department

The activities and associated resource requirements for this department are influenced by factors that are both internal and external to the organization. The key business drivers for the department are outlined below:

- Communications, consultation and engagement activities for new projects, infrastructure upgrades, rate changes, initiatives and proposals;
- Changes to government energy policies, regulation and standards;
- Communications of unplanned events, such as power outages;
- Customer, stakeholder and media requests for information and/or clarification;
- Renewals and /or changes to operating agreements with First Nations groups; and
- Employee communication requirements.

An example of a key communications initiative undertaken in 2012 was the education and awareness efforts necessary to inform customers of the new Residential Conservation Rate (RCR) introduced in July 1, 2012. The Company was proactive in informing and educating customers of the rate structure as well as undertaking comprehensive education and awareness efforts in order to manage customer concerns following the first winter under the new rate structure.

The business drivers identified above will continue into the five year forecast period. In recent years, environmental and energy policy has received a heightened focus at the provincial and municipal level and the Company expects this to continue over the next five years. Changes to energy policies impact the Company's marketplace and operating environment and therefore on-going collaboration and consultation with government and key stakeholders will be essential over the 2014-2018 period.

4.7.3 Communications and External Relations Review

The table below shows the O&M expenditures for the department for the period 2010 to 2013.

Table C4-11: Communications and External Relations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 556	$ 543	$ 493	$ 544	$ 496	$ 531
Non-Labour	1,083	926	751	925	944	959
Total O&M	**$ 1,639**	**$ 1,469**	**$ 1,244**	**$ 1,469**	**$ 1,440**	**$ 1,490**

The expenditure for 2011 was lower than 2010 by $170 thousand largely due to efficiencies realized in the sharing of resources with similar skill sets across the gas and electric operations. The 2012 expenditure was lower than 2011 by $225 thousand largely due to a vacancy not being filled in 2012 in a timely manner but this vacancy was not sustainable over an extended period of time, and due to higher cross-charges to capital. For 2013, expenditures for the department are forecast to be close to the 2013 approved level.

4.7.4 Communications and External Relations Forecast

The forecast O&M for the Communications and External Relations department for 2014 – 2018 is shown in Table C4-12.

Table C4-12: Communications and External Relations O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 547	$ 564	$ 581	$ 598	$ 616
Non-Labour	978	997	1,017	1,038	1,058
Total O&M	**$ 1,525**	**$ 1,561**	**$ 1,598**	**$ 1,636**	**$ 1,674**

The forecast expenditures over the 2014-2018 period is expected to remain steady from the 2013 base level with only annual inflationary increases over this period.

4.7.5 Communications and External Relations Summary

The business drivers identified above continue to remain relevant through the five year forecast period and FBC expects to maintain and deliver on customer and stakeholder expectations with no incremental funding beyond inflationary increases and with the existing department staffing levels.

4.8 *ENERGY SUPPLY*

4.8.1 Description of Energy Supply

The Energy Supply department is responsible for three broad functional areas – Resource Planning, Power Supply commercial operations, and the Company Load Forecasting. Energy Supply operates as a single, integrated group with resources allocated to the various functions to accomplish the required work. The purpose of each of these three functional areas and the scope of their activities are described in the following sections.

4.8.1.1 Resource Planning

The Resource Planning activities focus on the long term planning and procurement of resources to ensure the availability of cost effective long-term, reliable power for FBC's customers. Long term planning activities include monitoring and assessing the regulatory, policy, commercial and operational context within which FBC operates its load and peak demand forecasts, its current resource capabilities and the potential generation resource options available to meet its forecast needs. These responsibilities include the assessment and negotiation of the new or replacement contracted resources such as the power purchase arrangements with BC Hydro, and research and assessment of issues such as regional market regulatory developments and planning reserve margin requirements.

Resource planning activities are on-going; however a key responsibility is the development and implementation of the Company's Long Term Resource Plan in accordance with section 45 of the Utilities Commission Act and the Commission's Resource Planning Guidelines. The 2012 Long Term Resource Plan, with the exception of the proposal regarding planning reserve margin, was accepted by the Commission in May 2012 as part of Order G-110-12. The Company expects to file its next Long Term Resource Plan in 2016.

4.8.1.2 Power Supply

The main Power Supply activities consist of the commercial operations related to completing electricity commodity procurement both in advance and on an hourly basis as required. The sources of power are Company owned generating units, power supply contracts, and market transactions that range from hourly to several months. Power Supply is also responsible for selling any surpluses that may accumulate during spring runoff and, starting in 2015 when the Waneta Expansion comes into service, Power Supply will be responsible for mitigation activities to manage excess resources that may be available for sale to third parties.

Power Supply also plays a key role in helping to provide direction to System Operations so that the daily scheduling and back-office accounting processes, which are critical to the recording of the Power Purchase Expense, are optimized. Underpinning these purchase and sales activities are credit control measures monitored by Power Supply that help to ensure market transactions are executed successfully.

4.8.1.3 Load Forecasting

The primary Load Forecasting function is to produce the Company load forecast that is used as a key input to determine the revenue forecast, power supply costs and long term resource development to meet future loads. As part of the integration and harmonization efforts between the electric and gas utilities, the Company's electric forecast is managed under the purview of the gas utility's Forecasting department staff. However, the labour resources which prepare the load forecast are part of Energy Supply (electric) group.

4.8.2 Business Drivers for Energy Supply

Significant changes are occurring in the Energy Supply group's responsibilities due to the recently negotiated Power Purchase Agreement (New PPA) and related agreements. These changes are extensive and will require additional resources in order to successfully implement the agreements such that maximum benefits to customers are realized. A full description of the operational requirements of the New PPA have been referenced in the Company's recent support filing to the BC Hydro application for approval of the New PPA, in general they are:

- Annual PPA energy nomination and minimum take will require additional planning to identify the optimal energy nomination point and then to ensure the required purchases are implemented in the most cost effective such that the highest value displacement opportunities are realized.
- Forecasting and planning changes will be required to manage the risk of having insufficient energy. This may include greater use of short to medium term energy purchases.
- Additional and on-going effort will be needed to continually update the short term power requirements to reflect the changing expected weather to ensure that the purchase of New PPA power is meeting the nomination requirements under a variety of load requirement scenarios.
- System load and resource balance requirements have changed in that the Company does not have access to "Excess Energy" and "Excess Capacity" under its arrangement with BC Hydro. This will require more comprehensive real-time operations to ensure energy imbalance is not taken from BC Hydro. Imbalance events cost more as they occur more frequently; to ensure the maximum benefits are realized for customers under the New PPA, imbalance events must be kept to a minimum.
- Scheduling frequency has been increased such that additional effort must be made on a daily basis to determine the optimum PPA schedule for the next day taking into account the requirement to avoid imbalance.
- Information transfer to BC Hydro is increased such that there are additional requirements to coordinate with BC Hydro staff on a daily, weekly and monthly basis to review Power Supply operations.

In summary, in order to comply with the new agreements, FBC will need to:

- Increase planning and forecasting on an annual, monthly, daily and hourly basis;
- Complete more detailed after-the-fact accounting;
- Develop increased operational and accounting integration with BC Hydro;
- Improve data management and flow of information to BC Hydro;
- Provide training and create or update training materials for the FBC real-time, day ahead and after-the-fact staff; and
- Provide additional tools and IT solutions for the FBC operations staff in order to efficiently handle the changes and new contractual requirements.

As a result of these changes to operations, planning and accounting, combined with other developments impacting scheduling non-firm and wind power, FBC has identified the need for additional labour resources in the Power Supply group to fulfill the new requirements, and to maximize its ability to manage and mitigate power purchase expense in order to minimize costs on behalf of customers.

4.8.3 Energy Supply Review

The table below shows the historical O&M expenses of the Energy Supply department. The table shows that there has been a year over year increase in expenses as the department is required to manage the effects of the increasing complexity of the Energy Supply operations and to be able to take advantage of market mitigation activities in the more complex environment.

Table C4-13: Energy Supply O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 629	$ 631	$ 709	$ 772	$ 732	$ 784
Non-Labour	198	262	277	352	392	394
Total O&M	**$ 827**	**$ 893**	**$ 986**	**$ 1,124**	**$ 1,124**	**$ 1,178**

As shown in Table C4-13 above, the increase in the actual costs from 2010 to 2011 were mainly due to the work related to resource planning activities to support and implement the Resource Plan and negotiating the New PPA.

The increase from 2011 to 2012 was primarily the result of Resource Planning activities and further support to the System Control Centre (SCC) operations. SCC operations support includes providing real time operations support including assisting hourly market mitigation activities, monitoring and troubleshooting real time software, and completing the daily, monthly, quarterly, and annual financial reconciliations and reporting, as well as performing analysis to support short-term market mitigation power purchase decisions creating customer savings.

The 2012 actuals were lower than approved by about $80 thousand as a result of the late timing of the 2012 Decision that deferred work related to managing power supply expenses under the various agreements and load forecasting issues into 2013. While the 2012 actuals were below the 2012 approved amount, the savings recorded during 2012 were not permanent in nature. The 2013 expenditures are projected to come in at the 2013 Approved amount.

The Energy Supply group remains focused on optimizing opportunities for integration with the Gas business. During 2013 the manager of the gas load forecast assumed responsibility for overseeing the electric load forecast; resource sharing such as this between the electric and gas utilities allow resources to be focused in a more efficient manner to provide increased levels of support for the Power Supply function within the approved budget.

4.8.4 Energy Supply Forecast

Table C4-14 below provides a high level view of the forecast O&M for the Energy Supply department from 2013 to 2018.

Table C4-14: Energy Supply O&M Forecast ($thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 881	$ 983	$ 1,012	$ 1,042	$ 1,074
Non-Labour	402	410	418	427	435
Total O&M	**$ 1,283**	**$ 1,393**	**$ 1,430**	**$ 1,469**	**$ 1,509**

The Energy Supply department, in addition to general labour and non-labour inflation as discussed in Section C4.3.3 of the Application, is forecasting the following incremental pressures discussed below.

Costs in the PBR period reflect additional resources required beginning in 2014 and continuing annually thereafter to meet the obligations of the Energy Supply function. The drivers for these cost pressures are described above in Section C4.8.2. With power purchase costs expected to reach $141 million by the end of the period, these expenses are necessary and reasonable to ensure all contractual obligations are met and customers receive the full benefit of the contract flexibility and mitigation opportunities that are available. Non-labour expenses are expected to remain steady throughout the period.

4.8.5 Energy Supply Summary

The Energy Supply 2014-2018 forecasts reflect completed and on-going integration opportunities with the gas utility and productivity efforts, while recognizing the resource requirements to manage the Company's Power Supply, Resource Planning, and Load Forecasting functions over the next five years.

4.9 *INFORMATION SYSTEMS*

4.9.1 Description of Information Systems Department

Information Systems (IS) supports all business systems and technology used at FBC. This includes the following:

- Development of short and long term objectives 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 Systems 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.
- Ensuring cyber security and change control requirements are met and are subject to annual audits to confirm this. This includes compliance with the Cyber Infrastructure Protection (CIP) requirements as specified by the Mandatory Reliability Standards. Disaster recovery planning and capabilities for both operation and corporate infrastructure and systems are included in this area of responsibility as well.
- Providing end user technical support for all employees, contractors, applications and associated equipment.
- The management and monitoring of all telephony contracts, including cellular.
- The management and costs of all large printing devices for the organization. This includes ensuring printing contracts are yielding the highest value.
- 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.

4.9.2 Business Drivers for IS 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 five years and beyond, the demands on the IS department are expected to remain constant to ensure that FBC has the support for the technology required to meet business.

IS 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 ever 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.

4.9.3 IS Review

Support costs, particularly for software, have increased one to two percent annually over the past 3 years and have been largely mitigated through cost control and saving initiatives. 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 more and better information to users where and when they need it has increased the use of existing technology as well as new technologies. Information Systems must support and 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, travel and accommodations.

Information Systems has continually focused on cost control and saving initiatives such as:

- Savings have been realized by leveraging of contracts and buying power from joining with FBC Energy and from the larger organization, Fortis Inc.
- 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 Systems
- Additional video conferencing has allowed for certain remote meetings to take place without incurring travel costs.
- FBC continues to look for opportunities to use server virtualization standard in all aspects of the business and has become the standard for any request.

- Additionally desktop virtualization 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.

These savings have helped to offset the pressures of increasing wages, training and licensing costs helping to maintain stable IT operating costs. This could only be done with prudent reviews of our contracts and support model as illustrated in Table C4-15.

Table C4-15: IS O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,801	$ 1,731	$ 1,689	$ 1,755	$ 1,746	$ 1,871
Non-Labour	1,128	1,172	1,236	1,219	1,242	1,278
Total O&M	**$ 2,929**	**$ 2,903**	**$ 2,925**	**$ 2,974**	**$ 2,988**	**$ 3,149**

4.9.4 IS Forecast

The O&M forecast for Information Systems includes all labour, licensing, maintenance, training, travel and other expenses associated with operating and maintaining all applications, infrastructure, WAN and telephony. It includes all printing costs, excluding paper, for the Company as well.

Forecast O&M Expense for 2014 – 2018 is shown in Table C4-16 below. Information Systems expects to see only inflationary cost increases over the period.

Table C4-16: IS O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,927	$ 1,984	$ 2,044	$ 2,105	$ 2,168
Non-Labour	1,304	1,331	1,356	1,384	1,412
Total O&M	**$ 3,231**	**$ 3,315**	**$ 3,400**	**$ 3,489**	**$ 3,580**

4.9.5 Summary of IS

Information Systems regularly examines all of the above impacts and business requirements to find the appropriate balance of cost, risk mitigation and service. The forecast expenditures are necessary in order to manage, maintain, and support the IS infrastructure of the Company to meet the goal of providing safe reliable energy at a reasonable price.

4.10 *ENGINEERING SERVICES AND PROJECT MANAGEMENT*

4.10.1 Description of Engineering Services and Project Management Departments

The Engineering Services and Project Management organization is responsible for providing support for the safe and reliable delivery of electricity to customers and delivery of the capital program. The departments are comprised of the following functions:

- Asset Management is responsible for overseeing the electric transmission and distribution network assets, system capacity planning and maintenance planning to ensure safe and reliable energy delivery. This includes defining operations and maintenance activities for predictive and corrective maintenance of substations and lines assets. 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
- Engineering provides engineering design, drafting and technical services to the Project Management Office as well as technical support to Operations and other areas of the Company. Major activities for this department include:
    - Maintaining accurate mapping data of high-voltage electric facilities in the Geographic Information System (GIS);
    - Providing Engineering support for operational activities such as post-fault analysis and equipment failure investigations;
    - Developing and maintaining engineering standards for equipment and construction;
    - Participating in inter-utility technical groups such as WECC; the Northwest Power Pool (NWPP) and the Centre for Energy Advancement through Technological Innovations (CEATI).
- The Project Management Office delivers capital projects related to Generation, Transmission and Distribution assets. Prudent and efficient delivery of lines and stations projects is a key focus of the Project Management Office.
- The Mandatory Reliability Standards department is responsible for ensuring corporate compliance with the BC Mandatory Reliability Standards. On-going effort is required to ensure auditable compliance with all applicable standards and to evaluate the impacts of and implement changes to existing and new standards as well as processes and procedures (internal and external) to support the MRS program in British Columbia.

4.10.2 Business Drivers for Engineering Services and Project Management Departments

In general, the business drivers for the Engineering, Asset Management and Project Management departments are consistent with those of recent years. FBC, along with other utilities throughout the industry, continues to face the challenge of an aging workforce. In recent years the Company has found it difficult to attract and retain technical and engineering staff when recruiting. Going forward, the Company will continue to actively try to recruit skilled workers to support core business functions. Associated with this effort is the continuing requirement to ensure that new and existing employees maintain a high level of technical competence through attendance at training courses and technical conferences/seminars.

A relatively recent additional business driver is the requirement to maintain compliance with the BC MRS. The BC MRS Program requires that all registered entities maintain compliance starting in November 2010. Development of processes and procedures amongst the entities in British Columbia, WECC, and the BCUC is evolving and will continue to do so. In addition, there are on-going changes to existing standards and potential adoption of new standards. Impacts of changes to FBC will be reviewed and any cost adjustments identified.

The primary issue facing the Company with respect to BC MRS is the adoption of new standards, the revision of existing standards and/or process/procedure changes which are outside the Company's control. As a result, changes and additions to BC MRS could have a material impact on the effort required to maintain full and auditable compliance. The impact of changes on the Company's operations is unavoidable once adopted by the Province. Adjustments to processes and efforts may be required and may impact operating costs.

A number of standards are expected to come into effect during the five year period. For example, version 5 of the Cyber Infrastructure Protection (CIP) standards could be adopted as early as 2015 which could have a financial and manpower impact. NERC has a number of projects at various stages of development which may evolve into changes to the existing standards, addition of new standards or changes in interpretation during the time period.

In addition, the BCUC is currently conducting an inquiry into potential adjustments for the BC MRS Program. The results of the inquiry may impact operating costs.

4.10.3 Engineering Services and Project Management Review

Engineering Services and Project Management O&M expenses consist of the costs associated with maintaining technical competence, effort to support the operations of the organization and maintaining compliance with applicable mandatory reliability standards. Historical actual costs are shown in Table C4-17 below.

Table C4-17: Engineering Services and Project Management O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 928	$ 1,789	$ 1,951	$ 2,127	$ 1,974	$ 2,964
Non-Labour	314	574	664	664	848	903
Total O&M	**$ 1,242**	**$ 2,363**	**$ 2,615**	**$ 2,791**	**$ 2,822**	**$ 3,867**

For information, MRS costs are provided separately as this business function did not exist prior to 2011; in this presentation the MRS costs for 2012 and 2013 which are currently captured in deferral accounts[40] ($320,000 in 2012 and $900,000 in 2013) were added to the MRS O&M (2012 Actual and 2013 Projection) to show the true on-going costs of MRS, which are reflected in the 2013 Base O&M. The deferred MRS costs are not included in Table C4-17 above, which shows only costs recorded in O&M expense.

Table C4-18: Mandatory Reliability Standards O&M Review ($ thousands)
(Including Deferred O&M Expense)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ 856	$ 1,328	$ 914	$ 1,709	$ 1,770
Non-Labour	-	160	171	273	379	380
Total O&M	**$ -**	**$ 1,016**	**$ 1,499**	**$ 1,187**	**$ 2,088**	**$ 2,150**

Beginning in the early 2000s, the Company embarked on a period of significant infrastructure build to support customer growth (in both generation and transmission/distribution) and the resources of Engineering Services and Project Management were primarily devoted to supporting this effort. Today and going forward, the focus of Engineering Services is more driven by identifying and delivering sustaining capital and providing support to operations. The Engineering Services expenses increased from 2010 to 2013 due to an increased effort required for operations support as assets were put into service. Additionally, as approved by Order G-110-12, in 2012 and 2013 there was a one-time combined increase of $150,000 for external assistance to support the development of FBC asset management strategies.

Engineering Services and Project Management have been working to identify and implement 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:

[40] See Section D4.4.13.

- A common Director of Engineering Services for the electric and gas utilities has been appointed. Decision making is being pushed closer to the decision points creating greater accountability for all employees; and
- A common Manager, Project Management Office for the electric and gas utilities has been appointed, delivering lines and stations capital projects in a consistent, cost effective project management framework.

The Mandatory Reliability Compliance O&M expenses include the costs to maintain full and auditable compliance with the BC MRS program. This includes efforts for monitoring and maintaining security systems, field maintenance, on-going reporting requirements for the various standards, documentation and records, conducting self-audits, on-going training and participation in user groups, and evaluating impacts on changes to existing standards and adoption of new standards.

Following the implementation of MRS in BC in 2009, the first regular reporting cycle was for the year 2011; hence, the Company had only a limited understanding of the effort required and complexity of maintaining MRS compliance prior to development of the 2012-13 MRS O&M budgets. The following is a summary of events relevant to BC MRS Compliance since the development of those budgets in late 2011/early 2012:

- BCUC Letter L-56-11 (British Columbia's Mandatory Reliability Standards (MRS) Determination of Reference Amount for a Confirmed Violation). Process initiated on October 28, 2011 with a workshop held on March 27, 2012;
- FBC identified and self-reported on non-compliance with eight requirements and submitted mitigation plans. This was the first time that FBC reported non-compliance using the Rules of Procedure which involved the processes of Self-Reporting and Notice of Alleged Violation (NOAV);
- The Mandatory Reliability administrator (WECC) changed systems for entities to provide information, reporting and evidence in June/July, 2011. FBC did not have experience with the new system until the Company went through the Self-Certification, Self-Reporting and Auditing processes. This system continues to evolve;
- Completion and acceptance by WECC of mitigation plans requires in depth review, detailed evidence submission and verification/validation. A majority of the acceptance of mitigation plans for FBC occurred in the latter part of 2011 and throughout 2012;
- FBC's first MRS self-certification was completed in October 2011;
- FBC conducted an internal mock audit in December of 2011;
- Bill 30 was introduced in March 2012 and passed in May 2012. This bill amended the Utilities Commission Act and enabled the Commission to levy administrative penalties for non-compliance with the MRS program;

- FBC participated in its first BCUC/WECC Audit in July of 2012;
- BCUC issued order R-17-12 - Reliability Standards in British Columbia Amendment to Compliance Monitoring Program regarding Notices of Alleged Violations (NOAV). Process initiated on October 9, 2012 with a workshop held on November 21, 2012; and
- FBC attended user group meetings (which provided further clarification of WECC requirements) facilitated by WECC (October 18-20, 2011; January 31-February 2, 2012; October 15-17, 2012).

Since the development of the 2012-13 MRS O&M budget, FBC's understanding and interpretation of the effort necessary to meet the requirements of the standards has indeed changed, not only as a result of the audit itself but also through the Company's participation in user group meetings and through consultation with consultants and other utilities. Completions of the various tasks previously identified require more detail and effort, including changes to the expected processes, as well as an increased frequency of review than initially expected. Contributing to increased O&M costs is the completion of the mitigation plans required to achieve initial compliance with standards, which were largely exempt from self-reporting and self-certification while under mitigation. 2013 will be the first year in which the Company will not have a significant percentage of the requirements under mitigation, which increases the requirements for "24/7" compliance monitoring.

4.10.4 Engineering Services and Project Management Forecast

Table C4-19 sets out the departmental O&M forecast for the PBR period. Engineering Services and Project Management will continue to provide support for the safe and reliable delivery of electricity to customers and deliver the capital program. The forecasts to maintain the BC MRS program are indicated separately.

Table C4-19: Engineering Services and Project Management O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,053	$ 3,145	$ 3,239	$ 3,336	$ 3,437
Non-Labour	920	939	958	977	996
Total O&M	**$ 3,973**	**$ 4,084**	**$ 4,197**	**$ 4,313**	**$ 4,433**

Table C4-20: Mandatory Reliability Standards O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,823	$ 1,878	$ 1,934	$ 1,992	$ 2,052
Non-Labour	387	395	403	411	419
Total O&M	**$ 2,210**	**$ 2,273**	**$ 2,337**	**$ 2,403**	**$ 2,471**

The primary pressure within the PBR period for Engineering Services is the uncertainty around the continual changes with respect to MRS. Several factors can affect costs which cannot be quantified or identified at this time, some of which are:

- The Company will be audited twice (in 2015 and 2018) by the BCUC/WECC for compliance with the BC MRS program. The costs related to these two events are not included in the forecast and are considered incremental. FBC will be making future applications to the Commission for treatment of these costs as required.
- The in-progress BCUC inquiry may result in changes to the BC MRS program. The conclusion of the inquiry may result in adjustments to operating costs. These costs are currently unknown and not budgeted.
- On-going additions and changes to standards and processes/procedures. Annual reviews are conducted through the Assessment Report process. Adjustments to FBC's processes and efforts may be required and may result in adjustments to operating costs. These costs are currently unknown and not budgeted.

4.10.5 Engineering Services and Project Management Summary

Despite identified budget pressures over the PBR Period, Engineering Services 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 and compliance over the next five years.

4.11 *OPERATIONS SUPPORT*

4.11.1 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 Warfield, Kelowna, and Oliver, Operations Support is comprised of Supply Chain Services and Property Services as described in further detail below.

4.11.1.1 Supply Chain Services

- Material Services manages inventory levels and performs the physical movement of materials and equipment from the warehouse to locations throughout the service territory. Material Services also manages hazardous waste for FBC and provides field emergency response service as required by Operations.
- Procurement assists FBC departments acquire a variety of materials and services. Procurement ensures the appropriate processes are followed and agreements are in

place when FBC acquires materials and services. Furthermore, Procurement supports market research, risk management, tender evaluations and vendor management.

- Fleet Services provides three core functions: vehicle planning and acquisition, vehicle maintenance and support related to incident investigations and consultation on vehicle matters.

4.11.1.2 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.

4.11.2 Business Drivers for Operations Support Department

Operations Support's O&M costs continue to be driven by codes and regulations and system reliability requirements in support of the Operations Department maintenance plan and company's capital plan. Therefore, any change in regulatory requirements or industry and internal standards that significantly influences the activity levels for services performed by Operations Support will directly impact the funding required to provide these services.

4.11.3 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 to be realized in relation to the approved budget.

Provided in Table C4-21 below is an O&M overview of Operations Support's costs between 2010 and 2013.

Table C4-21: Operations Support O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 3,475	$ 3,510	$ 3,354	$ 3,510	$ 3,425	$ 3,669
Non-Labour	3,152	2,992	2,754	3,829	3,027	3,042
Recoveries	(5,633)	(5,186)	(4,868)	(6,087)	(5,247)	(5,453)
Total O&M	**$ 993**	**$ 1,315**	**$ 1,240**	**$ 1,252**	**$ 1,205**	**$ 1,258**

Operations Support realized cost savings in 2012 and anticipates continued cost savings throughout 2013. These savings are directly attributed to increased operational productivity by adjusting roles within Supply Chain to allow for a reduction in labour costs. In addition, the department realized lower vehicle costs through the buyout of a number of vehicle leases thereby reducing the cost of ownership and through lower than forecast fuel costs. As a result, Operations Support was able to project a reduction in total recoveries for its services below the approved budget in 2013.

4.11.4 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 required above 2013 projected levels. However, there are pressures to the O&M budget that are expected including labour inflationary increases, fuel cost increases and increases to property leases that require renewal within the PBR Period. The forecast O&M requirement for Operations Support is shown in Table C4-22 below.

Table C4-22: Operations Support O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,779	$ 3,892	$ 4,009	$ 4,130	$ 4,253
Non-Labour	3,103	3,166	3,229	3,294	3,359
Recoveries	(5,591)	(5,733)	(5,878)	(6,028)	(6,181)
Total O&M	**$ 1,291**	**$ 1,325**	**$ 1,360**	**$ 1,396**	**$ 1,431**

It should be noted that FBC has made reasonable assumptions for the forecast of fuel costs; however, the Company is subject to the risk of budget pressure should the gas price inflation increase above the forecast at any point during the term of the PBR Period.

Finally, Operations Support plans to continue pursuing opportunities for increased productivity by exploring the potential benefits of integration and further automation of business processes.

4.11.5 Operations Support Summary

In conclusion, Operations Support has generated cost savings while delivering safe and reliable service. These savings were achieved through a reduction in labour requirements resulting from adjusting roles within the department and through a reduction in vehicles costs. Looking forward, the department plans to continue to pursue opportunities for enhanced efficiency while achieving its corporate and departmental objectives.

4.12 *FACILITIES*

4.12.1 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 FBC. The services provided range from building asset operation and maintenance, physical security, space planning, office furniture and equipment and mailroom services. The department ensures that the Company and its employees have a suitable work environment with safe and efficient buildings and workspaces.

4.12.2 Business Drivers for Facilities Department

Codes and regulations, asset planning and productivity are the three main drivers of activity and costs within the Facilities department.

4.12.2.1 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.

4.12.2.2 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, improve equipment utilization and reliability, and enhance the health, safety and welfare of FBC employees. As this maintenance is cyclical, the spending pattern associated with these tasks vary based on manufacturer recommendations, best practices and code compliance. Maintenance levels will fluctuate over multiple years with a corresponding impact on the forecast 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 may require renegotiation.
- Administrative general – These costs vary with changes to headcount at FBC 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.

4.12.3 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 C4-23 below is an O&M overview of Facilities costs between 2010 and 2013.

Table C4-23: Facilities O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 578	$ 501	$ 386	$ 499	$ 422	$ 452
Non-Labour	3,122	3,219	3,210	2,967	2,967	2,074
Total O&M	**$ 3,700**	**$ 3,720**	**$ 3,596**	**$ 3,466**	**$ 3,389**	**$ 2,526**

The O&M expenses for the Facilities department have been relatively steady with a slight decrease in 2012 and 2013 due to a reduction in labour requirements, lease space and the cyclical nature of the maintenance work.

The 2013 Base has been adjusted for the purchase of the Trail Office building, as approved by Order G-110-12, and the resulting termination of the existing lease.

4.12.4 Facilities Forecast

The forecast O&M for the Facilities department is provided in Table C4-24 below. Facilities is anticipating the retirement of a senior position in 2014 and as a result has allowed for 6 months labour coverage for extensive training with the current incumbent. All other increases in labour are due only to labour and benefit inflation. In addition, Facilities is anticipating an overall step change reduction for non-labour costs as shown in Table C4-24 below.

Table C4-24: Facilities O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 517	$ 480	$ 494	$ 509	$ 524
Non-Labour	2,166	2,210	2,254	2,299	2,345
Total O&M	**$ 2,683**	**$ 2,690**	**$ 2,748**	**$ 2,808**	**$ 2,869**

The non-labour costs over the PBR Period are driven by cyclical maintenance, lease contracts and service contracts all of which are influenced by current market conditions. Provided below are two key impacts influencing the O&M requirement that Facilities is forecasting through the 2014-2018 PBR Period.

- Lease Contracts: FBC has three payable lease contracts of which one will be terminated in 2013 as a result of the purchase of the Trail.

- Service Contracts: The Provincial Government implemented a 17% 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 70 percent of the Facilities budget is for external contracts, services and material costs which are impacted by the many factors outside of FBC's control. Based on contractual commitments and market trending, FBC 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.

4.12.5 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 five year planning horizon, FBC will continue to prudently manage these costs while working to deliver a suitable work environment with safe and efficient building and workspaces.

4.13 *ENVIRONMENT, HEALTH AND SAFETY*

4.13.1 Description of EH&S Department

The Environment, Health and Safety (EH&S) department is made up of the following areas:

- Environmental Affairs manages environmental risks associated with operational activities and the fulfilment of compliance requirements aligned with environmental regulation;
- Occupational Health and Safety manages employee safety risk 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 about electricity, and about steps to be taken in emergency situations or in cases of metal theft or asset tampering. Awareness strategies also focus on the excavation and ground disturbance process in order to promote diligence in this process by anyone excavating in the proximity of utility assets.

FBC has in place environmental, safety and security management systems which address risks associated with the construction, operation and maintenance of its facilities. These management systems are in place to facilitate compliance with external legislation and regulations through policies, standards and procedures that are integrated throughout Company operations in order to ensure the safety of employees and customers as well as the protection of the natural environment. The Environment, Health and Safety (EH&S) department is responsible for the maintenance of these management systems. Enhancement and review of corporate guidelines, training programs, targets for continual improvement, and injury prevention programs are carried out through the review of these management systems.

4.13.2 Business Drivers for the EH&S Department

The Company operates and maintains about 7,000 km of power lines and 70 major facilities that are often located in close proximity to sensitive natural environments. FBC is committed to compliance with regulatory requirements in operating these existing facilities and in constructing new projects; an on-going challenge for the Company are the continual changes of these requirements due to revisions in legislation and industry best practices. The O&M costs incurred by the Environment, Health and Safety department are driven primarily by external legislative and regulatory requirements. There have been many changes or enhancements in the last five years with respect to safety and environment legislation, public expectation and awareness. Enhanced requirements occurred in areas such as:

- General hazard requirements with respect to confined space, cranes and hoists, avalanche preparedness and working alone;
- Facilities' applications for activities;
- Environmental impact assessments (federal and provincial);
- Environmental assessment screenings (federal and provincial);
- Fisheries Act Authorizations (e.g., approved work practices for riparian vegetation management limits; Vegetation management activities around fish-bearing streams to protect and conserve riparian habitat);
- Greenhouse gas monitoring and reporting
- SARA (Species at Risk Act) permits;
- Navigable Waters Protection Act;
- Riparian Areas Regulation for new utility corridor works in designated parts of the Province, requiring extra studies by Qualified Environmental Professionals and the consideration of other related provincial regulations;
- Provincial approvals for specified work activities or when specified areas are impacted including work impacting watercourses or wetlands, herbicide use, and municipal work permits; and
- Security monitoring and control.

Regulatory requirements that arise during FBC's operational works dictate the level of service, and the reporting and compliance activities that must be performed. These requirements may lead to additional measurement or reporting activities in future years, which may have an impact on O&M costs for the company. The impact of these additional activities on O&M requirements is difficult to quantify at this time. The following discussion identifies certain areas that FBC is currently monitoring.

4.13.2.1 Greenhouse Gas Management

FBC is now required to track greenhouse gas emissions, prepare reporting, have its reporting verified by external third parties, and then submit externally verified emissions reports to environmental regulators. Reporting requirements currently only apply to levels of imported electricity, as the company does not meet reporting thresholds for any other listed emission type.

On-going monitoring, reporting, and compliance with safety, security and environmental requirements are increasing the time, efforts and costs required to obtain permits, licenses, and authorizations to build, operate and maintain facilities.

4.13.2.2 Invasive Species

Invasive species found in natural working environments are continually monitored by the Company. Invasive aquatic mollusc species are of particular concern, including zebra mussels, quagga mussels and New Zealand mud snails, as they are predicted to spread toward western Canada. Eurasian Milfoil is another invasive aquatic plant that has entered Kootenay Lake. As lake temperatures increase the infestation will amplify, clogging intake trash racks and increasing the frequency and/or cost of maintenance of the racks. FBC consults with Invasive Species' Committees in order to best understand current awareness research efforts that will enable prevention and control activities as related to these types of invasive species.

4.13.2.3 Species at Risk (SARA)

SARA legislation continues to create uncertainty and concern for the hydro-electric industry. FBC and all other facility operators manage the Columbia River white sturgeon population that is listed as endangered. There are three additional fish species in the river system listed under SARA including: the Shorthead Scuplin (*special concern)* the Columbia Sculpin (*special concern*) and the Umatilla Dace (*special concern*). As the designation of current listed species continues to change, and as additional species continue to be added to the listing, critical habitat considerations, including recovery strategy analyses, environmental consulting fees, and additional permitting requirements must be considered for project related or for routine operations and maintenance works that currently do not attract these costs; furthermore, these costs may be unexpected if certain species fall into this category, triggering operational delays that may translate into additional costs. The uncertainty around SARA is specific to how the Department of Fisheries and Oceans Canada (DFO) intends to manage and interpret the SARA conditions and the legal challenges surrounding the implementation of the regulations. Resolution of the issues is very slow, and planning may become more challenging as the company adapts its current procedures in order to ensure compliance with all applicable requirements.

4.13.3 System Integration Issues

The current Environmental Management System ('EMS') is consistent with the ISO 14001 Standard. The Company, in 2012, attained a Certificate of Recognition (COR) recognized by WorkSafeBC as related to the Company's Safety Management System; the Safety and Environmental audit program for the company has now been aligned, and both utility divisions meet the requirements of the Enform Audit Standard. Further, facility security requirements are aligned with NERC (North American Electric Reliability Corporation) MRS (Mandatory Reliability Standard) requirements.

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.

4.13.4 EH&S Review

Table C4-25 below sets out the historical O&M for EH&S. A vacancy in the department was filled in late 2010, and an additional resource was retained in 2011 in order to review new security requirements related to the management of the BC MRS standards, in addition to metal theft concerns which have increased significantly. The 2013 Projected O&M represents a short term change in the trend due to the application of the COR rebate to the non-labour and temporary adjustments to the labour amount.

Table C4-25: EH&S O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 586	$ 689	$ 714	$ 760	$ 830	$ 889
Non-Labour	141	178	180	193	123	124
Total O&M	**$ 727**	**$ 867**	**$ 894**	**$ 953**	**$ 953**	**$ 1,013**

4.13.5 EH&S Forecast

The forecast O&M for the EH&S department is provided in Table C4-26 below. Forecast O&M for the department includes labour, maintenance, training, travel and other expenses associated with operating and maintaining the safety, security and environmental management systems for the Company. Departmental efforts are focused on supporting the reduction of incidents that can cause unnecessary cost burdens to the Company and its customers. In maintaining an integrated EH&S department, and in working closely with Operations' management, prevention programs can be synchronized in order to ensure that Company losses are minimized, and that future costs reflect primarily inflationary increases.

Table C4-26: EH&S O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 916	$ 943	$ 972	$ 1,001	$ 1,031
Non-Labour	127	129	132	134	137
Total O&M	**$ 1,043**	**$ 1,072**	**$ 1,104**	**$ 1,135**	**$ 1,168**

4.13.6 EH&S Summary

EH&S historical spending has been stable and the 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 aligned with FBC operations during this time, the costs of which will need to be absorbed through productivity offsets.

4.14 *FINANCE AND REGULATORY SERVICES*

4.14.1 Description of Finance and Regulatory Department

The Finance and Regulatory department is responsible for providing a range of financial and regulatory services to various departments throughout the Company.

4.14.1.1 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 declined from 17 employees in 2010 to 16 employees in 2013. FBC is not forecasting a change to the staffing level in the Finance department over the forecast period.

4.14.1.2 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 remained constant since 2010. FBC is not forecasting a change to the staffing level in the Regulatory department over the forecast period.

4.14.2 Business Drivers for Finance and Regulatory Department

4.14.2.1 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 managing tax audits, treasury activities and capital expenditures, as well the requirement to respond to the accounting and financial 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 establish more rules and standards. Regulatory applications and decisions are increasing in number and complexity which require an increase in financial modelling and forecasting, as well as applying the relevant accounting guidance. Accordingly, the Finance department is responsible for the on-going assessment and implementation of accounting guidance and standards. This may result in changes to accounting policy, adjustments to financial statement presentation and note disclosure, as well as changes to the financial reporting and accounting processes. Certain accounting guidance or regulatory decisions 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 to demonstrate the appropriate application of the accounting guidance for external auditors. Similarly, the outcome of increasingly complex regulatory and business decisions needs to be assessed in accordance with income tax legislation and regulations to ensure that the tax impacts are identified and applied appropriately.

Additional challenges for the Finance department include active involvement in the Company's forecast capital expenditures over the next five years. This will require the Finance department to manage debt financing, either through operating credit facilities or debt offerings, and the managing of budgets, accounting 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.

4.14.2.2 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 the complexity of FBC'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 and Regulatory Review section below.

4.14.3 Finance and Regulatory Review

Table C4-27 provides a high level view of actual and projected O&M expenses for the Finance and Regulatory department from 2010 to 2013.

Table C4-27: Finance and Regulatory O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 2,659	$ 2,887	$ 2,649	$ 3,067	$ 2,815	$ 3,016
Non-Labour	917	995	1,174	1,204	1,265	1,272
Total O&M	**$ 3,576**	**$ 3,882**	**$ 3,823**	**$ 4,271**	**$ 4,080**	**$ 4,288**

During the period 2010 to 2013 Projection, the Finance and Regulatory department has managed to meet its increasing business requirements while the O&M labour has moderately increased at an average of 2 percent per year. Labour costs temporarily declined in 2012 from 2010 and 2011 levels due to employee turnover and the Finance department having difficulty filling vacant positions. The financial complexities arising from accounting guidance and regulatory applications, as documented in the Business Drivers section, require the Finance department to be adequately resourced with a team who have the relevant financial skills and experience. It is due to difficulties in filling these vacancies on a timely basis that lower labour costs have occurred in the past, not due to a lack of need for the appropriate resources. The decrease in employee resources during 2012 was not sustainable over the long term and the Finance department was successful in recruiting candidates in 2013 which is reflected in the 2013 Projection O&M.

The increase in non-labour from 2010 to 2013 is due in part to incremental actuarial and accounting services, as well as taxation, treasury and cash management support provided by FHI. Other contributors to non-labour increases are related to external audit fees, rating agency fees, debt trustee fees, various filing fees and miscellaneous support costs.

The 2013 Projection is still approximately $0.2 million lower than the 2013 Approved, capturing some of the efficiencies realized to date and reflective of a continuation of the productivity focus.

4.14.4 Finance and Regulatory Forecast

Table C4-28 provides a high level view of the forecast O&M for the Finance and Regulatory department from 2013 to 2018.

Table C4-28: Finance and Regulatory O&M Forecast ($thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,106	$ 3,200	$ 3,296	$ 3,394	$ 3,496
Non-Labour	1,297	1,322	1,350	1,377	1,403
Total O&M	**$ 4,403**	**$ 4,522**	**$ 4,646**	**$ 4,771**	**$ 4,899**

Other than labour and general inflation as discussed in Section C4.3.3 of the Application, 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 and Finance service requirements are expected to continue to change and increase. The department will try to address this challenge by reviewing and streamlining existing work processes and capitalizing on integration and resource sharing opportunities, if any, between the Electric and Gas Finance departments.

1.1.1.1 Finance and Regulatory Summary

For the Forecast period, the Finance and Regulatory department is not projecting incremental funding required beyond that 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.

4.15 *HUMAN RESOURCES*

4.15.1 Description of Human Resources Department

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 12 Full Time Equivalent (FTE) employees, a reduction of approximately 14 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.

4.15.1.1 Corporate Human Resources

Corporate HR ensures that the HR direction and programs that effect 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.

4.15.1.2 Employee Services

Employee Services oversees the design and delivery of the Total Rewards framework to attract, retain and motivate employees. 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.

4.15.1.3 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.

4.15.1.4 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. FBC 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.

4.15.2 Business Drivers for Human Resources Department

The two main HR business drivers are an aging workforce and a focus on productivity.

4.15.2.1 Aging Workforce

In the labour market today, there is a mismatch between the skills employers seek and those available.[41] Experienced workers are retiring and as a result organizations are continuing to concentrate 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[42], the government of Canada describes labour market needs:

- "…between 2012 and 2020, the construction sector will need 319,000 new workers."
- "…95,000 Engineers will retire by 2020 and Canada will face a skills shortage…"
- the Petroleum producers "sector will need between 50,000 and 130,000 by 2020."
- the Electric energy "sector will have to recruit over 45,000 new workers – almost 48 percent of the current workforce by 2016."

A summary of the challenges of the aging workforce and FBC's plan to prudently manage demographic transitions is provided in Tab C4.3.6

4.15.2.2 Productivity

The prospect of increased labour demand and decreased access to skilled labour has organizations, including FBC, focusing on increased productivity. FBC continues to focus on streamlining processes, leveraging technology and optimizing opportunities from integration with the Gas utility to increase productivity.

In mid-2012, HR gas and electric services were integrated. Through integration, HR processes were reviewed and roles redesigned. While maintaining or improving service quality levels, HR has been able to manage additional workload within existing budgets during the 2012-2013 test period.

4.15.3 Human Resources Review

Table C4-29 below sets out the 2010 through 2013 O&M for Human Resources. O&M costs increased in 2011 due to a transfer of costs to HR from the Communications budget for employee events. Overall, O&M is not increasing above inflationary costs in 2012 and 2013. The shifting of resources from labour to non-labour O&M in 2012 and 2013 are as a result of electric HR labour cross charging to gas and the receiving of gas labour costs in electric non-labour accounts. Projected costs in 2013 are aligned with the amount approved.

[41] 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

[42] http://www.budget.gc.ca/2013/doc/plan/chap3-1-eng.html, taken March 24th, 2012

Table C4-29: Human Resources O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,309	$ 1,217	$ 1,047	$ 1,370	$ 1,128	$ 1,208
Non-Labour	329	530	769	504	746	750
Total O&M	**$ 1,638**	**$ 1,747**	**$ 1,816**	**$ 1,874**	**$ 1,874**	**$ 1,958**

In 2012, 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. During the integration, roles were redesigned and repurposed for integrated program offerings. 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 will enable the movement of staff throughout the company and enable operational flexibility through mobility of the workforce.

Alignment of the employee programs achieved efficiencies in administration. During the test period HR was able to produce greater output in recruiting and employee development and minimize the impact of costs associated with labour contract negotiations. In 2012, employee development produced eLearning capability and provided seven Corporate HR (i.e. Business Ethics, Workplace Violence Prevention) and two Safety recertification eLearning modules to employees in addition to on-going business acumen, leadership development and safety training. In 2013, 69 jobs were filled as of May 1, 2013, an increase of 39 percent over the same time period in 2012. Legal costs associated with contract negotiations with COPE and IBEW are being offset by O&M savings achieved through efficiencies.

4.15.4 Human Resources Forecast

Table C4-30 sets out the 2013 Base and the high level 2014-2018 operating and maintenance forecasts for Human Resources. Overall, HR is not forecasting any material increases in non-labour or labour costs. Labour cost increases are as a result of wage/cost escalation for labour and benefit inflation; no additional employee resources are forecast.

Table C4-30: Human Resources O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,244	$ 1,282	$ 1,320	$ 1,360	$ 1,400
Non-Labour	765	780	796	812	828
Total O&M	**$ 2,009**	**$ 2,062**	**$ 2,116**	**$ 2,172**	**$ 2,228**

The need to sustain a culture of productivity improvement continues to influence HR programs. HR will continue to deliver efficient services through programs like the e-learning training delivery model.

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 gas and electric 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 test 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.

4.15.5 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 e-learning 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.

4.16 *GOVERNANCE*

4.16.1 Description of Governance Department

The governance department consists of legal services, insurance and risk management, and internal audit.

4.16.1.1 Legal Services

By way of a shared services agreement, FHI provides legal services to FBC. The legal department in FHI 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.

Legal Services has one full-time administrative support position. This is expected to remain the same during the PBR period.

4.16.1.2 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, the cost of the premiums paid for those policies, and policies and management of both insured and self-insured claims.

4.16.1.3 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 the Company's internal controls. Internal Audit's responsibility has expanded over the past several years to include audits or reviews of projects such as Mandatory Reliability Standards, corporate integration, and several other emerging operational areas impacting corporate strategy. 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 three employees. The forecast for internal audit reflects the expected net charges to the Gas division.

4.16.2 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 FBC. The majority of costs for the three departments consist of external legal costs, insurance premiums, and labour costs.

4.16.3 Governance Review

Table C3-31 below sets out the historical O&M for each Governance area.

Table C4-31: Governance O&M Review ($ thousands)

	2010 Actual		2011 Actual		2012 Actual		2013 Approved		2013 Projection		2013 Base	
Labour	$	284	$	215	$	313	$	428	$	428	$	459
Non-Labour		2,000		1,816		1,821		1,945		2,062	$	2,072
Total O&M	**$**	**2,284**	**$**	**2,031**	**$**	**2,134**	**$**	**2,373**	**$**	**2,490**	**$**	**2,531**

Legal Services faces increasing demands and complexities related to several recurring and on-going external factors. Regulatory applications and decisions, regulatory processes, and compliance requirements are increasing in number and complexity which require greater examination and analysis by both internal as well as external legal resources. Regulatory processes are typically attracting more interveners, taking longer, and costing more than in previous years. This increased interest and associated time and cost requirements continue to put pressure on Legal Services. Additional pressures on the provision of Legal Services are the newly imposed Mandatory Reliability Standards, securities, and privacy compliance.

Insurance expenditures include labour charges from FHI, insurance premiums, and insurance claims. Insurance premiums are impacted by market factors outside the control of FBC which can include large global losses, catastrophic risks such as earthquakes, hurricanes and forest fires, as well as through general market conditions related to unpredictability of investment returns and loss history. All of these factors can result in either positive or negative volatility. FBC is proposing that variances from forecasts of third-party premiums be subject to deferral and refunded to, or recovered from, customers in later years. This deferral treatment is even more appropriate in a long-term PBR as proposed in this application.

4.16.4 Governance Forecast

The table below shows the O&M forecast for the Governance department for the PBR Period.

Table C4-32: Governance O&M Forecast ($ thousands)

	2014 Forecast		2015 Forecast		2016 Forecast		2017 Forecast		2018 Forecast	
Labour	$	472	$	486	$	501	$	517	$	532
Non-Labour	$	2,219	$	2,297	$	2,374	$	2,515	$	2,537
Total O&M	**$**	**2,691**	**$**	**2,783**	**$**	**2,875**	**$**	**3,032**	**$**	**3,069**

General labour and benefit inflation will be a cost pressure as discussed in Section C4.3.3. 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.

Insurance expense is forecast to escalate at a rate higher 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 D4.3.5 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.

4.16.5 Governance Summary

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 will be 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.

4.17 *CORPORATE*

4.17.1 Description of Corporate Department

The Corporate department consists of the following costs:

- Fortis Inc. Corporate Services Fee;
- Board of Director costs;
- Executive Management team (Executive) costs;
- Other corporate related costs/ recoveries; and
- Employee future benefit cost adjustments (post 2013).

4.17.2 Business Drivers for Corporate Department

4.17.2.1 Fortis Inc. Corporate Services Fee

Fortis Inc. provides certain specialized services and expertise to its subsidiaries, including FBC. These services are shared amongst the Fortis Inc. group, thereby providing economies of scale to FBC. KPMG reviewed the services and the appropriateness of their allocation in a report to FEI dated June 10, 2013, which is included in this Application as Appendix F2. The report concluded that:

> *"KPMG is of the view that the corporate services cost pools and cost allocators proposed for use in the FI and FHI corporate services cost allocation models both meet the internally generated objectives and evaluation criteria established by FI and FHI as detailed in Section 4 of this report, and as a result form a reasonable and objective basis of allocation." (Appendix F-2, Page 32)*

The services to be performed by Fortis Inc. over the PBR Period are consistent with the services provided by Fortis Inc. to FBC in 2012 and 2013, and were approved by the Commission for recovery in the 2012-2013 RRA Decision Order G-110-12.

The services performed by Fortis Inc. are strategic, corporate governance in nature, provide access to the equity capital markets and furnish equity funding of the utility and consist of the following functions:

- Fortis Inc. 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.
- 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, 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.

Although Fortis Inc. incurs costs in support of the utilities, certain costs are specific to the holding company and have been excluded from the Fortis Inc. Corporate Services Fee. These excluded costs are:

- All identifiable corporate development costs;
- Costs associated with non-regulated entities: and
- Stock compensation costs.

FBC customers benefit from the efficiencies realized by allocating appropriate Fortis Inc. costs across its subsidiaries.

4.17.2.2 Board of Director Costs

The Board of Director costs include the costs relating to the corporate governance of the Board, the Audit and Risk Committee and the Governance Committee (Committees) of FBC. The majority of the Board is comprised of independent directors.

The Board and its Committees provide a key corporate function to FBC which include the following: ensuring the continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, providing oversight over the corporate activities of the Company, and developing and maintaining governance procedures and policies.

4.17.2.3 Executive

The Executive provides the strategic direction, leadership and management for the Company.

4.17.2.4 Corporate Other

The expenditures and recoveries in this account are generally of a one-time project nature, such as charge-outs for non-regulated work, and therefore tend to vary from year to year.

4.17.2.5 Employee Future Benefit Cost Adjustments

The forecast change in Pension and OPEB expenses from the 2013 Projection over the PBR Period has been accumulated in this Corporate O&M account.

4.17.3 Corporate Review

Table C4-33 below is a summary of the total Corporate O&M department and shows the actual costs incurred in 2010 through 2012 with the projected and approved costs for 2013. The labour component in the tables below consists primarily of salaries and benefits for the Executive and Executive assistants. The non-labour component consists of the Executive non-labour costs, Fortis Inc. Corporate Services Fees, Board of Director costs, and any one time non-labour corporate costs.

Table C4-33: Corporate O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 2,329	$ 2,049	$ 1,459	$ 1,995	$ 1,607	$ 1,722
Non-Labour	1,181	2,435	1,985	2,230	2,193	2,204
Total O&M	**$ 3,510**	**$ 4,484**	**$ 3,444**	**$ 4,225**	**$ 3,800**	**$ 3,926**

The following describes each of the Corporate O&M components.

4.17.3.1 Fortis Inc. Corporate Service Fees

Table C4-34 is a summary of the Fortis Inc. Corporate Services Fee allocated to FBC and shows the actual costs incurred in 2010 through 2012 with the projected and approved costs for 2013.

Table C4-34: Fortis Inc. Corporate Service Fees O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
	$ 1,283	$ 1,612	$ 1,868	$ 1,585	$ 1,725	1,725
Total O&M	**$ 1,283**	**$ 1,612**	**$ 1,868**	**$ 1,585**	**$ 1,725**	**$ 1,725**

The costs from Fortis Inc. are allocated to FBC using the assets by subsidiary driver which is a valid cost driver given the organizational structure of Fortis Inc. This allocation method was approved by the Commission in the 2012-2013 RRA Decision Order G-110-12. As mentioned above the Fortis Inc. cost pools and allocation methodology were reviewed by KPMG and found to be reasonable. The increase in costs is attributable primarily to the increase in FBC's asset base relative to the Fortis group of companies, inflation over the period and the loss of sundry income from the rental of poles at Fortis Inc. effective January 1, 2011.

4.17.3.2 Board of Directors

The following table C4-35 is a summary of the Board of Directors costs and shows the actual costs incurred in 2010 through 2012 with the projected and approved costs for 2013.

Table C4-35: Board of Directors O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
	$ 289	$ 268	$ 241	$ 275	$ 245	246
Total O&M	**$ 289**	**$ 268**	**$ 241**	**$ 275**	**$ 245**	**$ 246**

Prior to July, 2010 FBC had a separate Board and Committees and incurred 100% of the costs. Effective July 1, 2010 the Board of Directors became a joint Board that is shared amongst FBC and FHI. All costs incurred for compensation and certain other Board and Committee expenses are shared between FBC and the FHI based on a Massachusetts Formula. 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. The Massachusetts Formula results in an approximately 23 percent allocation to FBC of the shared Board of Director and Committee costs for 2013. The Massachusetts Formula was approved by the Commission as the Board of Director pooled costs allocation method in the 2012-2013 RRA Decision Order G-110-12.

The Board costs vary between years due to the number of Board members, the number of meetings and inflation.

4.17.3.3 Executive

The following table C4-36 is a summary of the Executive costs and shows the actual costs incurred in 2010 through 2012 with the projected and approved costs for 2013.

Table C4-36: Executive O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 2,329	$ 2,049	$ 1,459	$ 1,995	$ 1,607	$ 1,722
Non-Labour	185	245	163	370	223	233
Total O&M	**$ 2,514**	**$ 2,294**	**$ 1,622**	**$ 2,365**	**$ 1,830**	**$ 1,955**

The labour expense consists of Executive salary and benefits directly paid by FBC and cross charges from FEI for Executive oversight from those Executive employed by FEI, offset by cross charges to FEI for Executive oversight from those Executive employed by FBC.

In the summer of 2010, FBC and the FEI began sharing common members of the Executive. The integration of the Executive has evolved such that all Executive have joint oversight of FBC and FEI effective January 1, 2012. This structure allows for sharing of more specialized resources and economies of scale. The Company benefits from the expertise of a broader depth of experience, for less than the cost of a stand-alone Executive.

Executive costs are substantially less than 2010 due to the sharing of the Executive Management team between FBC and FEI. The integration savings have been partially offset by labour escalation and inflation.

As approved in the 2012-2013 RRA Decision Order G-110-12, FBC and FEI currently cross charge the Executive costs based on time estimates. The cross charge includes a fully loaded wage, without any overhead.

As the entire Executive now has oversight over FBC and FEI, it would be more appropriate to allocate the Executive pooled costs (fully loaded wage without any overhead) based on a Massachusetts Formula. This will allow for a more streamlined and efficient approach of allocating the costs, while ensuring an appropriate allocation methodology. The results of the Massachusetts Formula for 2013 would allocate approximately 23 percent of the Executive pooled costs to FBC. FBC is requesting approval to allocate the pooled Executive costs (fully loaded labour costs with no overhead) to FBC and FEI using the Massachusetts Formula effective January 1, 2014.

4.17.3.4 Corporate Other

The following table C4-37 is a summary of the Corporate Other costs and/recoveries and shows the actual costs/recoveries incurred in 2010 through 2012 with the projected and approved costs for 2013.

Table C4-37: Corporate Other O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
	(576)	310	(287)	-	-	$ -
Total O&M	**$ (576)**	**$ 310**	**$ (287)**	**$ -**	**$ -**	$ -

The 2010 and 2012 amounts primarily include recoveries of executive time working on non-regulated activities. These activities were charged out in accordance with the FBC Code of Conduct (COC) and the Transfer Pricing Policy (TPP) discussed further in Section D3.6. Corporate Other costs/recoveries is projected to be nil for 2013.

4.17.4 Corporate Forecast

The following Table C4-38 provides an overview of the Corporate O&M by labour, non-labour and the employee future benefit cost adjustments.

Table C4-38: Corporate O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,773	$ 1,826	$ 1,881	$ 1,938	$ 1,996
Non-Labour	2,337	2,454	2,471	2,572	2,625
Pension	(505)	(1,107)	(1,715)	(2,265)	(2,758)
Total O&M	**$ 3,605**	**$ 3,173**	**$ 2,637**	**$ 2,245**	**$ 1,863**

The following Table C4-39 provides an overview of the Corporate O&M by each of the components previously discussed.

Table C4-39: Corporate O&M Forecast by Business Driver ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Fortis Inc. Costs	$ 1,848	$ 1,955	$ 1,963	$ 2,054	$ 2,096
Board Costs	251	256	261	266	272
Executive	2,011	2,069	2,128	2,190	2,253
Corporate Other	-	-	-	-	-
Pension	(505)	(1,107)	(1,715)	(2,265)	(2,758)
	$ 3,605	**$ 3,173**	**$ 2,637**	**$ 2,245**	**$ 1,863**

During the PBR Period, the Fortis Inc charges are projected to increase based on FBC's relative asset base compared to the other Fortis Inc. subsidiary utilities, as well as inflation.

Board and Executive costs are forecast to increase by labour and non-labour inflation. Both the Board and Executive pooled costs are expected to be driven by the allocation between FBC and FEI using the Massachusetts Formula.

The Company has not forecast any costs/recoveries for Corporate Other over the PBR term.

The Employee Future Benefit Cost Adjustment presented in the Corporate O&M is representative of the change in pension and OPEB expense included in the 2013 Base O&M as compared to the forecast pension and OPEB expense for the PBR term of 2014 to 2018. The Company's third party actuary has prepared forecasts based on FBC's assumptions to support the employee future benefits expense which has been forecast to decrease over the PBR term. Variances between actual and forecast employee future benefits expense will be captured in

FBC's existing Pension and OPEB variance deferral account approved pursuant to Order G-110-12. In this Application, FBC has forecast employee future benefits expense for 2013 through 2018. The 2015 through 2018 forecast amounts are excluded from the proposed PBR O&M formula and are forecast to demonstrate the expected trends over the PBR Period. The annual employee future benefits expense will be re-forecast and updated as part of FBC's RRA filings and Annual Reviews during the PBR period.

4.17.5 Corporate Summary

For the PBR Period, the Corporate department is not projecting incremental funding requirements beyond that of general inflation. The forecasts include the Sharing of Services allocation methodology discussed in Section D3.5 of this Application.

4.18 *ADVANCED METERING INFRASTRUCTURE IMPACT*

As detailed in the application for a CPCN for the AMI project, FBC expects the implementation of AMI to affect the O&M requirements for the following departments:

- Information Systems;
- Customer Service;
- Operations; and
- Operations Support.

AMI is expected to increase the O&M requirements for certain departments, while decreasing O&M requirements for other departments. Overall, the implementation of AMI will result in a net decrease in FBC's O&M requirements. A brief discussion of the nature of the O&M impact by department resulting from the AMI project is provided below.

4.18.1 Information Systems

The O&M requirements for Information Systems are increased as a result of the implementation of AMI, primarily due to the additional staff required to support the AMI system, as well as the hardware, licensing, and support costs associated with the project. Table C4-40 below details the forecast AMI-related O&M impact for the 2014-2018 test period for Information Systems.

Table C4-40: AMI O&M Impact – Information Systems ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 289	$ 623	$ 634	$ 654	$ 665
Non-Labour	477	587	597	607	618
Total O&M	**$ 766**	**$ 1,210**	**$ 1,231**	**$ 1,261**	**$ 1,283**

4.18.2 Customer Service

The O&M requirements for Customer Service are decreased as a result of the implementation of AMI, primarily as a result of the elimination of the manual meter reading function and the costs associated with that function. Table C4-41 below details the forecast AMI-related O&M impact for the 2014-2018 test period for Customer Service.

Table C4-41: AMI O&M Impact – Customer Service ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 136	$ (665)	$ (2,063)	$ (2,131)	$ (2,270)
Non-Labour	-	(65)	(164)	(166)	(176)
Total O&M	**$ 136**	**$ (730)**	**$ (2,226)**	**$ (2,298)**	**$ (2,446)**

4.18.3 Operations

The O&M requirements for Operations are decreased as a result of the implementation of AMI, primarily due to the elimination of meter exchanges for compliance testing purposes during the 2014-2018 test period, as well as a reduction in costs related to the remote disconnect/reconnect functionality of the AMI meters. O&M requirements related to meter exchanges for compliance testing purposes are expected to return to pre-AMI levels in 2022. Table C4-42 below details the forecast AMI-related O&M impact for the 2014-2018 test period for Operations.

Table C4-42: AMI O&M Impact – Operations ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ (497)	$ (625)	$ (820)	$ (724)	$ (990)
Non-Labour	(37)	(117)	(153)	(159)	(165)
Total O&M	**$ (534)**	**$ (742)**	**$ (973)**	**$ (883)**	**$ (1,155)**

4.18.4 Operations Support

The O&M requirements for Operations Support are decreased as a result of the implementation of AMI and the associated reduction in the required number of meter reading vehicles. Table C4-43 below details the forecast AMI-related O&M impact for the 2014-2018 test period for Operations Support.

Table C4-43: AMI O&M Impact – Operations Support ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ -	$ -	$ -	$ -	$ -
Non-Labour	-	(176)	(443)	(450)	(477)
Total O&M	**$ -**	**$ (176)**	**$ (443)**	**$ (450)**	**$ (477)**

4.18.5 Advanced Metering Infrastructure Impact Summary

The implementation of AMI will result in some additional O&M costs related to the on-going support requirements for the system, as well as a reduction in O&M requirements related to the elimination of the manual meter reading function, as well as a reduction in the requirement to physically visit all premises that require a service reconnect or disconnect. Table C4-44 below details the overall net O&M impact resulting from the implementation of AMI for the 2014-2018 test period.

Table C4-44: Total AMI O&M Forecast Impact ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ (71)	$ (667)	$ (2,248)	$ (2,201)	$ (2,594)
Non-Labour	439	229	(163)	(168)	(200)
Total O&M	**$ 368**	**$ (439)**	**$ (2,411)**	**$ (2,369)**	**$ (2,794)**

In the event that the proposed AMI project is not approved as proposed, FBC will file an amendment to this application reflecting the removal of the O&M impacts attributable to the implementation of AMI.

4.19 *SUMMARY*

FBC has a requirement to operate and maintain its generation, transmission, and distribution system in a manner that reflects its focus on customers, productivity, demographics and system reliability and safety. This Application contains FBC's forecast of those costs and a reasonable estimate of 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 FBC would expect to file for under annual cost of service applications if it were not filing for a PBR Plan.

5. CAPITAL EXPENDITURES

5.1 *INTRODUCTION*

This section discusses the capital expenditures of FBC during the period of 2014-2018. In this Application, FBC presents its capital expenditures which include Costs of Removal, exclusive of Capitalized Overheads, Direct Overheads, and Allowance for Funds Used during Construction (AFUDC)[43]. An overview of projects for which the Company expects to apply for Certificates of Public Convenience and Necessity (CPCN) is provided in Section C5.7. The projects discussed below are consistent with the projects identified in FBC's 2012 Long Term Capital Plan, filed as part of the 2012 Integrated System Plan.

5.2 *2014-2018 PBR PLAN CAPITAL CATEGORIES*

In this Application, FBC 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 all capital expenditures traditionally included in Sustainment, Growth and Other Capital (previously referred to as General Plant). The objective of this classification is to include all 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 single exception to this treatment is the Advanced Metering Infrastructure (AMI) Project, which is the subject of an application for a CPCN filed on July 26, 2012. The regulatory process for review of the AMI Project concluded on May 30, 2012, and approval of the AMI Project is expected shortly.

The determination of the formula-based capital expenditures is provided in Section B6.2.5.

The forecast capital expenditures are provided below for reference purposes only; 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.

[43] See Section E Table 1-A-1 for a reconciliation of capital expenditures for Plant in Service.

5.3 REGULAR CAPITAL ADDITIONS: SUSTAINMENT, GROWTH AND OTHER CAPITAL

5.3.1 Categories of Capital Expenditures

The rate base for FBC for 2014 and beyond will be affected by capital expenditures in 2013 and those in the future. Consistent with the 2012-2013 RRA, FBC's regular capital expenditures are divided into the following categories:

- Sustainment Capital – Consists of expenditures for system reinforcements to the generation, transmission and distribution assets, as well as replacements and upgrades to the generation, transmission and distribution assets to ensure safety, integrity and reliability.
- Growth Capital – Consists of expenditures for infrastructure upgrades required to meet customer and associated load growth.
- Other Capital – Consists of expenditures for Information Systems, Vehicles, Metering, Telecommunications, Facilities, and Tools and Equipment.

The regular capital additions components of Plant-in-Service 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 FBC, as well as a reconciliation of the 2013 Base capital expenditures that forms the starting point for the 2014 – 2018 formula and projections.

5.3.2 Historical Capital Expenditures

Table C5-1 below shows the Company's level of capital spending from 2010 through 2013. FBC's 2012 actual capital spending was approximately $30 million less than approved as FBC was not able to complete all of its planned capital work for 2012, partly due to the timing of the 2012-2013 RRA Decision. 2013 spending is projected to be approximately $30 million higher than 2013 approved amounts, however this forecast includes expenditures of approximately $38 million related to the acquisition of the distribution assets of the CoK. When adjusted for the CoK acquisition and for delays related primarily to the timing of the AMI project as well as the completion of work initially scheduled for 2012 but delayed to 2013 due to the timing of the 2012 – 2013 RRA Decision, spending for 2013 is projected to be approximately $6 million less than approved.

Table C5-1: Historical FBC Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Approved	2013 Projection
Generation - Regular Capital	3,589	2,128	4,386	4,039	2,363	2,823
Generation - Major Projects	13,966	13,828	2,599	2,935	-	425
Total Generation Capital	17,555	15,956	6,985	6,973	2,363	3,248
Transmission-Station-Distribution Regular Capital	42,999	34,719	29,731	45,130	36,591	52,031
Transmission-Station-Distribution Major Projects	61,489	13,389	6,003	10,892	11,886	45,230
Total Transmission-Station-Distribution Capital	104,488	48,108	35,734	56,022	48,477	97,261
Other - Regular Capital	8,448	11,605	7,974	10,689	16,146	10,755
Other - Major Projects	-	540	1,700	9,367	34,985	21,929
Total Other Capital	8,448	12,145	9,674	20,056	51,130	32,684
Total Gross Capital Expenditures	130,491	76,209	52,393	83,052	101,970	133,193

5.3.3 Base and Forecast Capital Expenditures

In order to set the base level of capital expenditures for application of the PBR formula, FBC uses 2013 Approved capital expenditures as a starting point, less those expenditures which are not representative of on-going requirements. Finally, similar to the method of determining 2013 Base O&M Expense, certain factors that will impact capital expenditures in future, but which were not accounted for in 2013, are added. As discussed in Section B6 of the Application, the adjustments reflect:

1. Elimination of major or non-recurring types of capital;
    - Corra Linn Unit 3 completion;
    - Corra Linn Unit 2 Life Extension;
    - Okanagan Transmission Reinforcement Project;
    - Kelowna Bulk Transformer Capacity Addition;
    - PCB Environmental Compliance (substations component);
    - Trail Office Lease Purchase;
    - Kootenay Long Term Facilities Project;
    - Okanagan Long Term Solution Project;
    - Central Warehousing Project; and
    - Advanced Metering Infrastructure Project.
2. The return to PST; and
3. The capital portion of increased 2013 pension amounts.

Table C5-2 below shows how these items have been allocated to the three categories of capital. Total PST and pension adjustments are allocated on the total costs attributable to a category of capital as a percentage of total capital expenditures.

Table C5-2: 2013 Base Adjustments ($ thousands)

	2013 Approved	Less Major Projects	Applicable to Formula	PST	Pension	2013 Base
Generation Sustainment Capital						
All Plants Concrete and Structural Rehabilitation	408	-	408			
Lower Bonnington Powerhouse Windows	4	-	4			
All Plants Minor Sustainment Projects	1,032	-	1,032			
Upper Bonnington, South Slocan & Corra Linn Powerhouse Windows	131	-	131			
Upper Bonnington Old Plant Various Unit Upgrades	378	-	378			
Lower & Upper Bonnington & Corra Linn Fire Panels	231	-	231			
All Plants Public Safety and Security	179	-	179			
	2,363	**-**	**2,363**	**19**	**86**	**2,468**
Transmission, Stations and Distribution Sustainment Capital						
Transmission Sustainment	5,378	-	5,378			
Station Sustainment	1,723	-	1,723			
PCB Environmental Compliance	9,021	(9,021)	-			
Distribution Sustainment	8,828	-	8,828			
Communications Upgrades	318	-	318			
SCADA System Upgrades	584	-	584			
	25,852	**(9,021)**	**16,831**	**132**	**616**	**17,579**
SUSTAINMENT CAPITAL	**28,215**	**(9,021)**	**19,194**	**151**	**702**	**20,047**
Transmission, Stations and Distribution Growth Capital						
Ellison to Sexsmith Transmission Tie	318	-	318			
Kelowna Bulk Transformer Capacity Addition	2,865	(2,865)	-			
New Connects	17,198	-	17,198			
Ellison Feeder 2 to Sexsmith Feeder 1 Tie	908	-	908			
Distribution Small Growth Projects	714	-	714			
Distribution Unplanned Growth Projects	622	-	622			
GROWTH CAPITAL	**22,625**	**(2,865)**	**19,760**	**155**	**723**	**20,638**
OTHER CAPITAL						
Buildings	769	-	769			
Furniture & Fixtures	106	-	106			
Fleet	2,260	-	2,260			
Telecommunications	159	-	159			
Meters	353	-	353			
Tools	398	-	398			
Information Systems	4,089	-	4,089			
Trail Office Lease Purchase	10,000	(10,000)	-			
Kootenay Long Term Facility	7,980	(7,980)	-			
Okanagan Long Term Solution	31	(31)	-			
Advanced Metering Infrastructure	24,985	(24,985)	-			
	51,130	**(42,996)**	**8,134**	**64**	**298**	**8,495**
TOTAL CAPITAL EXPENDITURES	**101,970**	**(54,882)**	**47,088**	**369**	**1,723**	**49,180**

Table C5-3 below provides the forecast capital expenditures by category, starting from the 2013 Base as calculated above. FBC is forecasting pension expense to decrease over the 2014 – 2018 test period, which will reduce the labour component of capital expenditures. The forecast amount of pension decrease compared to 2013 is shown in the following table.

Table C5-3: Forecast FBC Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Generation	2,468	3,155	2,940	2,944	3,010	2,847
Transmission, Station & Telecommunications	8,359	16,171	9,821	9,480	11,073	11,520
Distribution	9,220	11,827	12,092	14,164	14,248	14,503
Total Sustainment Capital	20,047	31,153	24,854	26,587	28,331	28,869
Growth Capital						
Transmission, Station & Telecommunications	332	3,187	3,190	-	293	2,928
Distribution	20,306	15,102	14,732	15,589	15,764	16,916
Total Growth Capital	20,638	18,289	17,922	15,589	16,057	19,844
Other Capital						
Information Systems	4,271	5,290	6,134	5,791	5,747	5,721
Vehicles	2,360	1,948	1,783	1,749	1,907	1,945
Meters Changes	369	-	71	109	114	118
Telecommunications	166	156	159	162	166	169
Buildings	803	1,044	912	942	961	980
Furniture & Fixtures	110	260	531	87	88	90
Okanagan Long Term Solution	-	120	122	3,800	-	-
Advanced Metering Infrastructure	-	16,765	18,233	583	741	604
Total Other Capital	8,495	26,078	28,449	13,738	10,247	10,162
Pension Adjusments	-	(345)	(789)	(1,233)	(1,608)	(1,915)
Total Gross Capital Expenditures	49,180	75,176	70,435	54,681	53,028	56,960

A discussion of the Sustainment Capital, Growth Capital, and Other Capital categories is provided below. As well, a discussion is provided of projects that are not included in the table above, but for which FBC expects to submit applications for a Certificate of Public Convenience and Necessity during the 2014 – 2018 period.

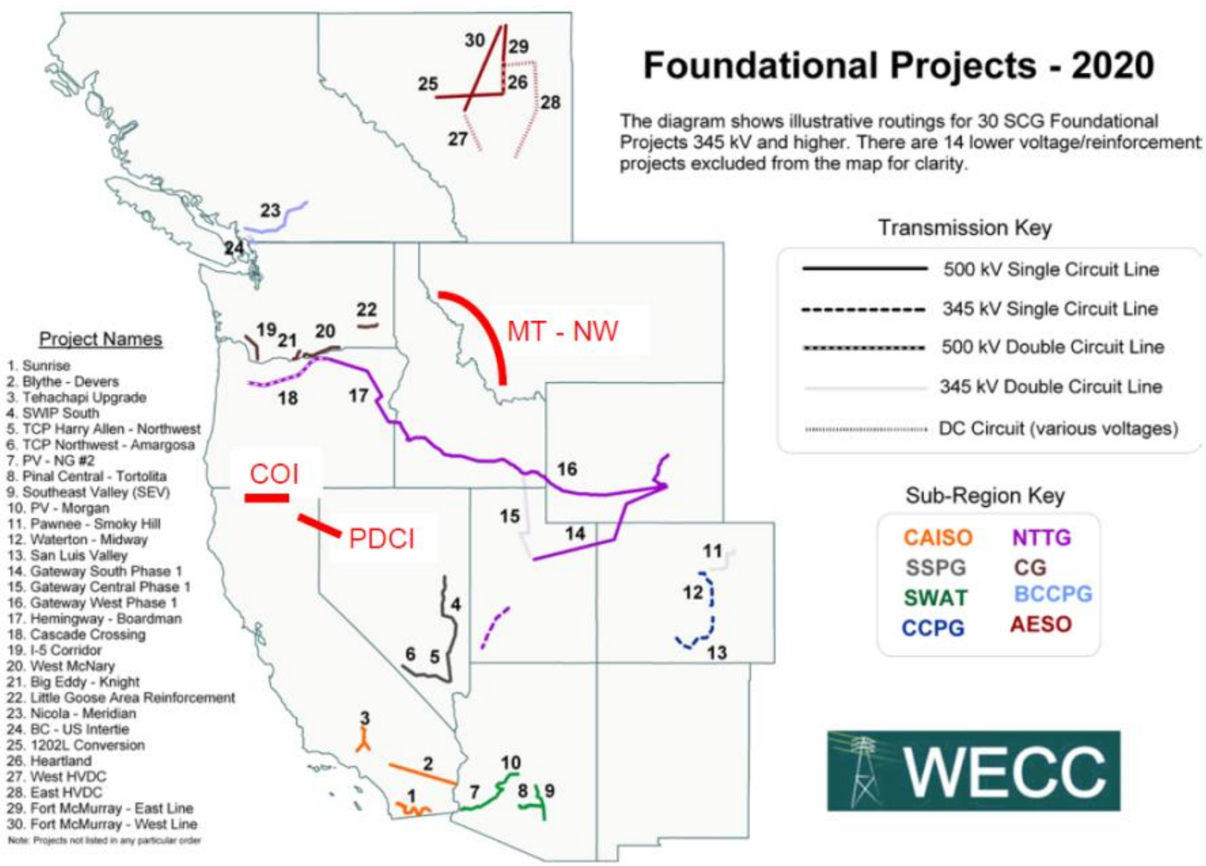
5.3.4 Inflation Assumptions

FBC forecast capital expenditures over the PBR period have been prepared using an inflation rate of two percent per year. However, it should be noted that there is potential for a higher inflationary pressures than currently forecast which would impact the forecast capital expenditures.

The potential for additional inflationary pressures is driven by the number of possible major utility transmission infrastructure construction projects in western North America during the 2014-2018 test period, and the associated high demand for labour, materials and resources required to complete the construction. With competition for limited resources as these 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[44] and similarly Kinder Morgan's oil pipeline to Burnaby, BC. As well, the development of new gas resources and demand from LNG export facilities are expected to result in additional labour and resource pressures. According to the advisory firm Ernst & Young[45], 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.

According to the WECC Subregional Planning Group there are approximately 100 planned electric transmission projects by 2020 in western North America. Figure C5-1 below depicts the routing for 30 of the potential transmission projects listed by the WECC Subregional Planning Group.

Figure C5-1: WECC Foundational Projects - 2020



44 From Pipeline News North – May 10, 2013

45 From Financial Post article titled "Canada could face massive hurdles in move to build $50B methane superhighway" – February 28, 2013.

5.3.5 FBC Asset Management Strategy

5.3.5.1 Background

FortisBC is 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 execution. The desired outcome of these enhancements is improved transparency, allowing stakeholders to have a better understanding of how FortisBC's decisions will mitigate risks, improve performance and reduce non-essential costs.

The Asset Management Strategy is being built to incorporate established industry practices while leveraging the systems and processes that FortisBC already has in place in both the Electric and Gas divisions. For example, the Gas division's Long Term Sustainment Plan and the Electric division's Integrated System Plan will be integral aspects of the Asset Management Strategy. These processes will be supported by FortisBC's existing information systems, which will be integrated to provide an optimized, single view of how FortisBC manages both Gas and Electric assets.

The development of the Asset Management Strategy was initiated following the *2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan BCUC Decision 5.2.2.3 (a)*[46]. For this initial stage of planning FortisBC engaged the support of KPMG LLP (KPMG) to perform a high-level review of asset management practices, systems and tools to identify priority improvement areas and set the roadmap forward.

The PAS55 (Publicly Available Specification 55) Standard combined with KPMG's perspective on leading practices in asset management were used for the review. The PAS55 Standard 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. PAS55 is recognized as a leading standard for assessing asset management in organizations. The standard encapsulates a collection of industry best practices into a model for companies to follow. PAS55 has been widely adopted by many utilities in EU countries. FortisBC is aware that other Canadian utilities are looking to PAS55 as a guide for their improvements in asset management.

FortisBC's activities under this initiative can be summarized into the three following steps. The outcomes of these activities are outlined below:

5. High-level review of asset management practices, systems and tools to identify areas of focus for improvement;

[46] 2012-2013 RRA Decision, page 64

6. Development of vision and goals for asset management in FortisBC; and
7. Identification of priority improvements and options.

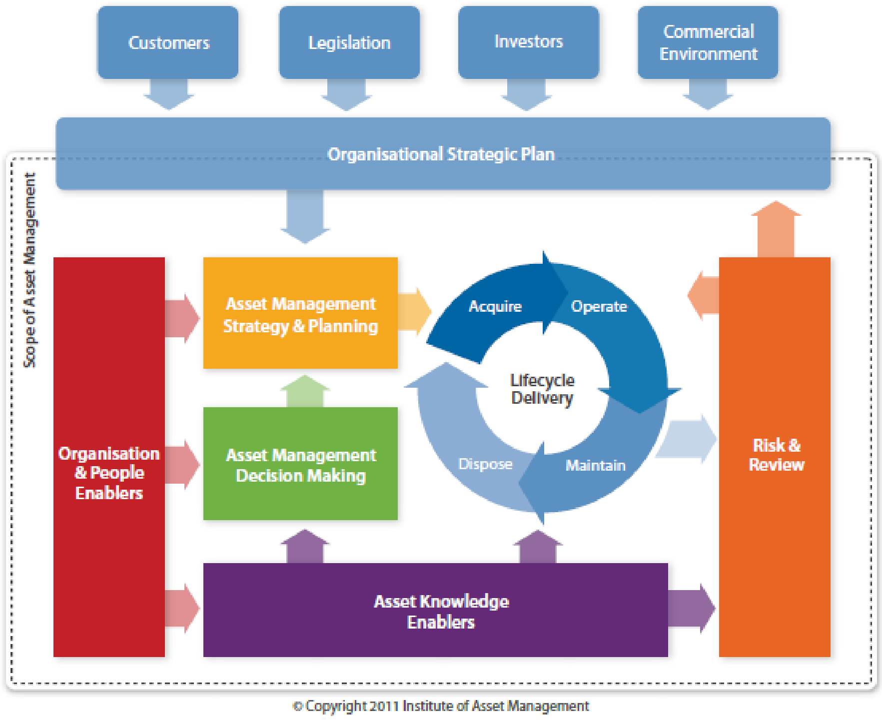
5.3.5.2 Outcomes

A high-level review of asset management competencies and practices was the first step in the strategy development; undertaken with the objectives of identifying issues and opportunities which should be addressed. A secondary objective of this activity was to build awareness and understanding with staff on required changes.

The review was executed across both the Electric and Gas divisions, and was a cross-functional exercise incorporating input from Engineering, Operations, Regulatory, IT, and Finance. Using an integrated asset management model, the analysis highlighted focus areas across the six domains of asset management: Asset Management Strategy & Planning; Asset Management Decision Making; Lifecycle Delivery; Organization and People Enablers; Asset Knowledge Enablers; Risk and Review.

These domains are consistent with the Institute of Asset Management's (IAM) publication *Asset Management – an anatomy; Version 1.1; February 2012* shown in the graphic below. The IAM is an institute supporting organizations in implementing practices consistent with PAS55. Utilizing this model ensured a broad-based review of FortisBC's entire asset management process.

Figure C5-2: IAM Conceptual Model for Asset Management[47]



5.3.5.2.1 ASSET MANAGEMENT VISION AND GOALS

Following the high level review, FortisBC defined a future vision – common across Gas and Electric – for how asset management can help FortisBC and its stakeholders achieve their goals. This vision is summarized in the Asset Management Strategy vision statement:

> *Making sound decisions in the interest of our customers is at the heart of everything we do at FortisBC.*
>
> *Through a transparent, robust, and integrated asset management practice, combined with FortisBC's culture of accountability, we ensure that our team is equipped to consistently make defendable decisions which are optimized and in the best interest of our customers.*
>
> *Under this model FortisBC can effectively and efficiently maintain our commitments to the public on safety, reliability, and managing lifecycle costs.*

Supporting this vision are four key principles that FortisBC believes are the foundation of the asset management strategy. These principles also represent the goals for the asset

[47] Institute of Asset Management's (IAM) publication Asset Management – an anatomy; Version 1.1; February 2012; page 16; found here http://theiam.org/what-is-asset-management/anatomy-asset-management

management strategy and the value that FortisBC will be pursuing from each improvement implemented within this program.

1. Consistent and defendable decisions using a transparent process - Internal and external stakeholders can better understand asset management decisions since they are made in a consistent and transparent manner.
2. Optimized decisions - Decisions are supported by the best data available, improving the ability of FortisBC to effectively balance decisions on costs, reliability and safety.
3. High accountability and ownership over assets – Employees are accountable and are engaged in their role in delivering safe, cost effective, and reliable services to rate payers. Employees take on their day-to-day responsibilities like “owners” of the assets they are responsible for.
4. Integrated partnership model – The asset management planning department works closely with other departments and stakeholders to develop robust and achievable plans which balance sustainable system needs and regional priorities.

5.3.5.2.2 PRIORITY ASSET MANAGEMENT IMPROVEMENT AREAS

FortisBC has identified a number of improvement opportunities which will help the organization achieve its vision for asset management. There are four main categories of improvements which are currently being reviewed, scoped, and advanced.

1. Organizational structure improvements – Integration of Gas and Electric asset planning and sustainment functions to ensure consistency and leverage the strengths of each department. Embedding more asset management expertise into regions and other departments. Updating of role definitions to include competencies which support an integrated asset management process.
2. Process improvements – Alignment of the planning and risk assessment processes between Gas and Electric, and across different network assets (e.g. generation, distribution, transmission, etc.), with the objective of integrating planning activities, ensuring appropriate internal and external stakeholder considerations, and optimizing planning across both sides of the business and in each region.
3. Decision-making support tools – Extension and improvement of existing decision support tools to improve the ability of planners to make optimal decisions based on best available information and leading practices. Publication of these tools will help communicate decision-making processes to stakeholders and contribute to the goal of transparent decisions. These tools will also facilitate integration between Gas and Electric.

4. Data collection and analytics – Improve asset data collection and analytics by aligning information systems across Gas and Electric to have one seamless process for accessing information on assets to improve planning, execution and reporting capabilities. Fully leverage information on assets to optimize the decision-making process.

FortisBC is currently in the process of developing plans to advance these improvement opportunities.

5.4 *SUSTAINMENT CAPITAL EXPENDITURES*

5.4.1 Sustainment Capital Overview

FBC sustainment capital expenditures involve projects required to maintain the safety and reliability of the electrical system, and to ensure that plant in service is managed to provide service over its full life expectancy. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects. The sustainment capital budgets presented below have been developed using existing practices and some enhanced asset management strategies.

Although FBC has estimated forecast sustainment expenditures to the best of its ability, it is not possible to forecast expenditures for every possible contingency. For example, capital costs related to changes to BC MRS standards/processes or revisions to standards/processes are not included in the PBR. The BC MRS program provides annual reviews of potential changes/additions to standards/processes through the Assessment Report process. This process allows entities to identify costs required to meet new standards or revisions to standards and, once approved in BC, would require adjustment to expenditures. Any capital costs related to changes or additions are currently unknown and not budgeted.

A summary of the 2013 base and forecast Sustainment Capital expenditures for the 2014 – 2018 test period are provided below.

Table C5-4: Forecast FBC Sustainment Capital Expenditures

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Generation	2,468	3,155	2,940	2,944	3,010	2,847
Transmission, Station & Telecommunications	8,359	16,171	9,821	9,480	11,073	11,520
Distribution	9,220	11,827	12,092	14,164	14,248	14,503
Total Sustainment Capital	20,047	31,153	24,854	26,587	28,331	28,869

The following sections describe the Sustainment Capital expenditures for each area.

5.4.2 Generation Sustainment Capital

Generation sustainment capital expenditures are used to complete multiple projects that have been identified at the generating plants as a result of safety inspections, storm damage, aging equipment, reports by personnel and other inspections. There are eight Generation Sustainment capital projects included in this Application:

- Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels;
- Corra Linn Spillway and Spillgate Engineering;
- All Plants Safety and Security;
- All Plants Fire Safety;
- All Plants Concrete and Structural Rehabilitation;
- Upper Bonnington and Corra Linn Powerhouse Windows;
- Dam Safety Instrumentation; and
- All Plants Minor Sustainment Capital.

5.4.2.1 Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels

This project is the final year of a three year program which involves the installation of fire alarm annunciation panels at the Upper Bonnington, Lower Bonnington, and Corra Linn generating stations. This project is intended to enhance the safety of personnel working onsite.

The planned fire alarm panel will be multi-zone and will include fire pull stations; audible alarms, visual alarms, fire detectors and smoke detectors. Alarm panels will not include controls nor will they be linked to a suppression system. The fire panel will annunciate to a central monitoring location.

5.4.2.2 Corra Linn Spillway Concrete and Spill Gate Rehabilitation

In mid-2011 the provincial government updated the *BC Dam Safety Regulations* to be consistent with the Canadian Dam Association Dam Safety Guidelines. Under the updated regulations dams are now classified under five categories instead of the four categories previously used. Each category has a corresponding design flood and design seismic event which are used when evaluating the safety of the dam as required under the regulations. FBC contracted a subject matter expert to conduct a Dam Safety Review and determine the consequence classification for the Corra Linn dam which resulted in a reclassification from the Very High to Extreme category. As a result of the reclassification, the specified design flood event and design seismic event against which the dam is evaluated have increased. Although FBC does not anticipate any issues with the increase in the design flood event associated with the reclassification, the change in the design seismic event is expected to result in some required structural modifications to enhance the withstand capacity of the Corra Linn dam.

As a result of the reclassification, FBC's original plan of isolation, access, sandblasting and recoating the spill gates has now increased in scope to include:

- Reassessment of the dam's ability to withstand a seismic event;
- Secondary power supply added to operate the spill gates;
- Refurbishment of gate hoist mechanisms;
- Upgrade of structural towers; and
- Upgrade of spillway gates.

FBC will conduct a detailed engineering analysis for this project beginning in 2015. The analysis will be conducted primarily using third party engineering firms, and include failure modes analysis, preliminary design for access, internal FBC design reviews, detailed design for access and detailed design for isolation. Expenditures for the execution phase of the project will be the subject of a separate application for a CPCN as further discussed in Section C5.7.6 below.

5.4.2.3 All Plants Safety and Security

This project will upgrade the safety and security at the four FBC generating plants by increasing public awareness of the hazards associated with these sites. Security will be improved through increased signage and perimeter fencing which will restrict access to dangerous or controlled areas. Safety will be improved by the addition of tailrace sirens that sound in the event of changing water levels. This work will minimize the risk of a public or employee incident related to access to FBC facilities, and is considered Good Utility Practice consistent with recommendations in the Public Safety and Security section of the BC Dam Safety Review Guidelines, and with the recommendations set out by the Canadian Dam Association.

5.4.2.4 All Plants Fire Safety

This project involves upgrading the fire egress from the power houses at all four river plants. The upgrades include new exits from the river side of the turbine floor to the outside via the operating floor, adding fire exit crash bars to the doors, installing fire stop material to all openings between rooms and floors and upgrading the generator fire deluge system.

The purpose of the project is to modernize the river plants in terms of fire safety. The installation of additional doors and crash bars facilitates a faster evacuation response time for exiting the plants in the event of a fire. The addition of fire stops also allows localization and containment of a fire to one area in the plants. Upgrading the generator fire deluge system through the addition of deluge solenoid valves that are ULC compliant is a requirement stipulated by FBC insurance underwriters.

5.4.2.5 All Plants Concrete and Structural Rehabilitation

The FBC generation plants range in vintage from 70 to 100 years old. This project involves the correction of deficiencies and degradation in concrete and structural steel installations related to normal deterioration that has occurred over time. A comprehensive third party engineering inspection of the plants has identified locations that require resurfacing of deteriorated concrete, repair of waterway structures such as spillway piers, forebay piers, forebay walls, spillway walls, tailrace piers, as well structural steel deficiencies. The deterioration creates employee safety hazards and operational issues and could potentially contribute to structural failure. If not addressed proactively, the deterioration will continue to accelerate resulting in increased expenditures in future years to address the issues.

FBC has defined the “Concrete and Structural Rehabilitation” project as a group of projects at all four FBC plants with individual estimates of less than $1 million to be completed as an eighteen year program; 2014 will be the third year of this program. By grouping all Concrete and Structural Rehabilitation jobs into one ongoing program, flexible prioritization of project completion is facilitated which will ensure a sustainable level of investment is maintained avoiding the need for large scale rehabilitation projects in future years.

5.4.2.6 Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows

This project involves the refurbishment and replacement of deficient and broken windows at the Upper Bonnington, Slocan and Corra Linn hydroelectric generating plants.

Unlike modern powerhouses, these three powerhouses are of the vintage where no HVAC (heating, ventilation, and air conditioning) has ever been installed. The safe opening and closing of these windows is vital for temperature regulation of the generating units and within the powerhouses. Cooling air is drawn in through the tailrace vents, is circulated around the generators to cool them, and then vents out into the operating floor area. The windows must be opened in order to provide an exit for the hot air. There are three rows in total, but only the middle row is opened and closed regularly.

The existing windows are 70 years old, approximately 1.8 meters wide and up to 3.6 meters tall and weigh approximately 225 kilograms each. The windows are steel framed, and typically have two openings that measure approximately 1.8 meters wide by 1 meter tall. The movable portion of the window weighs approximately 70 kilograms. Many hinges are worn due to age and usage, and as a result the windows are at risk of falling out. As the opening style is such that an operator must pull on a chain or rope located approximately 6 meters below the actuator mechanism, there is a safety risk to the operating personnel during operation of the windows. Further, due to the worn hinges, windows on occasion slam shut which causes the glass panes to break with consequent falling glass.

FBC completed the replacement and refurbishment of the Lower Bonnington windows in 2012, and will complete the replacement and refurbishing of windows identified to be at risk of failure at South Slocan in 2013.

As part of the BCUC directed reductions in 2012/2013 capital expenditures, FBC has rescheduled the remaining window refurbishments and replacements over multiple years. The program will continue during the 2014 – 2018 period to address the remaining windows identified to be at risk of failure at the Upper Bonnington and Corra Linn plants.

5.4.2.7 Dam Safety Instrumentation

This project involves the upgrade of existing dam safety instrumentation as well as the installation of additional instrumentation at all four FBC plants. The upgrades will include the replacement of devices to monitor pressure within the dam structure, installation of equipment to monitor changes in the stability of the dams after seismic events, and equipment to assess seasonal changes in a dam leakage.

5.4.2.8 All Plants Minor Sustainment Capital

FBC has defined the “All Plants Minor Sustainment Capital” program at Generation as a collection of small individual projects with individual estimate levels of less than $0.5 million. By grouping all small sustainment projects into one ongoing project, flexible prioritization of project completion is facilitated.

The type of work required can range from replacement of fans and motors, upgrade of crane components, and replacement of embedded piping. In all cases, the individual projects are estimated less than $500,000 in value. By grouping all small sustainment projects into one ongoing project, FBC is able to spread the cost over multiple years and manage the expenditures based on the priority and needs at that time. It also provides a mechanism to complete small capital projects which arise throughout the year as a result of unanticipated component failures, safety issues or damage due to freshet or storms which otherwise would not be budgeted for.

5.4.3 Station Sustainment Capital

FBC substation asset management is driven by a combination of time-based and condition-based scheduling. The Company has been moving towards a more comprehensive condition-based approach for the last several years, however to date this transition and philosophy has not been fully defined and implemented. FBC does employ a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC’s substation assets and is used to assist in scheduling maintenance tasks. There are ten Station Sustainment capital projects included in this Application:

- Environmental Compliance (PCB Mitigation);

- Station Urgent Repairs;
- Station Assessment/Minor Planned Projects;
- Ground Grid Upgrades;
- Osoyoos 63 kV Breaker Addition;
- DG Bell 138 kV Breaker (CB13) and Voltage Transformer Addition;
- Bulk Oil Breaker Replacement;
- Oil Containment;
- Distribution Transformer Replacements; and
- Minimum Oil Circuit Breaker Replacement

5.4.3.1 Environmental Compliance – Station Equipment (PCB Mitigation)

2014 represents the final year of FBC's efforts to remediate substation equipment (the PCB Program) contaminated with Polychlorinated Biphenyls (PCBs) in order to become compliant with the *PCB Regulations*. FBC made an application in the 2011 Capital Expenditure Plan, and the 2012-2013 Capital Expenditure Plan for expenditures necessary to identify and remove or mitigate the risk of release of PCBs into the environment. Through Commission orders G-195-10 and G-110-12, the Company has received approval to expend $24.674 million to complete this task. As directed in G-110-12, the Company has filed semi-annual progress reports on this project.

5.4.3.2 Station Urgent Repairs

The Station Urgent Repair program is required to address unexpected failures of in-service equipment. Factors that can result in component failures in substation systems include inclement weather, defective equipment, animal intrusions, and vandalism. These failures can cause outages or present safety or equipment risks that must be addressed in an expedient manner to maintain safe and reliable service. Annual spending varies due to the severity and number of equipment failures. The estimate for this project is based on a three year average of historical expenditures, adjusted for inflation and changes in overheads.

5.4.3.3 Station Assessment/Minor Planned Projects

This program involves ongoing condition assessments of the Company's 65 substations for environmental, safety and reliability issues on a ten year cycle, and the completion of the required work identified from these assessments.

The Station Assessment and Minor Planned Projects program address the whole substation system, including equipment such as transformers, breakers, batteries, and ground grids. The work resulting from the condition assessments is planned and executed in the subsequent years as Station Minor Planned Projects. The list of projects scheduled in the budget year may change if a new previously unidentified project is deemed a higher priority. The grouping of all minor planned projects into one ongoing project allows for flexible prioritization of the various projects.

5.4.3.4 Ground Grid Upgrades

Station ground grids must function properly in order to minimize safety risk for employees and the general public who are in or around stations. In the event of an electrical fault on the system, the purpose of the ground grid is to provide a low impedance return path for fault current. If the ground grid is damaged or has deteriorated, the fault current can potentially follow other paths such as through communications systems or water systems. This can result in increased hazard to employees and the general public.

Consistent with recommended IEEE practices, FBC employs an ongoing program to test the effectiveness of ground grids at all stations. The purpose of ground grid testing is ensure a strong electrical connection to ground, to provide a common ground reference for the station, and to minimize ground potential rise. Strong electrical connections to ground reduce the safety risk to personnel in stations during faults and help protective relays to effectively clear ground faults. As part of the program, station ground grids will be inspected and tested during scheduled Station Assessments. The assessments will determine if a ground grid study is required, with any remediation work identified as a result of the study prioritized based on the station criticality and location. Both condition assessments and the ground grid studies are used to develop plans for any required remediation work.

5.4.3.5 Osoyoos Substation 63 kV Breaker Additions

The T1 and T2 transformers at the Osoyoos substation are 15 MVA and 20 MVA respectively and have fuses protecting the transformers on the high voltage side. Consistent with IEEE recommended practices, the current FBC standard for the high voltage protection of transformers over 10 MVA is to provide transformer protection using circuit breakers or circuit switchers. Installing circuit breakers for the Osoyoos transformers T1 and T2 will bring them up to current standards. As part of the project, isolating switches will be installed upstream in order to allow the circuit breakers to be serviced.

The existing fuses coordinate poorly with upstream transmission line protection, provide no power transformer overload protection and provide poor backup for downstream devices. In addition, fuses have longer clearing times (0.4 – 2.0 seconds) for low voltage bus faults, increasing the fault duration and possibility for equipment damage. Fuses can also cause single-phasing and customer equipment damage when only one high voltage fuse link operates. Circuit breakers will provide better protection to the transformers and also increased protection to the low voltage bus and breakers, improved isolation, quicker restoration time in the event of trips, increased reliability and improved employee safety. This increases the likelihood that any possible resulting transformer damage will be minimized, allowing the transformer to be more easily repaired.

5.4.3.6 DGB 138 kV Breaker and Voltage Transformer Addition

This project involves the addition of a circuit breaker (CB13) at the DG Bell Terminal Station. The project will improve and simplify the protection scheme at the terminal station and increase operational reliability in the Kelowna Area.

Currently, the ring bus at DG Bell is operated with three circuit breakers; CB11, CB12 and CB14. The addition of CB13 breaker in the allocated position between CB12 and CB14 will complete the 138 kV ring bus at the station. The DG Bell Terminal Station has been designed and provisioned to have a four-element ring bus in the 138 kV portion of the station, with the isolating switches for CB13 installed. The addition of the fourth circuit breaker will improve reliability, operational flexibility and simplify the substation protection schemes. The recent installation of a capacitor bank to the existing node between CB14 and CB12 has increased the number of devices connected to this bus section. Currently, the DG Bell T1 and T2 transformers, the mobile transformer connection and the capacitor bank are all included in the same protection zone. A fault with one piece of equipment will cause all units in this zone to experience an outage.

With the installation of CB13 the amount of equipment connected to a single node will be decreased. By reducing the amount of equipment on this node, reliability will be improved as a fault on the bus or a particular piece of equipment is isolated to its node, leaving other nodes and equipment energized. This project also includes the addition of voltage transformers on the high voltage side of transformer T1 between CB12 and CB13 in accordance with FBC design standards. The voltage transformers will complete the ring bus and simplify the protection scheme, bringing it up to standard station design. These changes will improve customer reliability by decreasing the possibility of false trips.

5.4.3.7 Bulk Oil Breaker Replacements

FBC has a total of 25 bulk oil circuit breakers manufactured between 1938 and 1983. Eight of these bulk oil circuit breakers are scheduled to be replaced under the PCB Environmental Compliance program. Two circuit breakers are scheduled to be replaced as part of growth projects, and the remaining 15 units, manufactured in the 10 year period from 1973 to 1983, are the focus of this program. These units each contain approximately 200 litres of insulating oil; however none of these high voltage bulk oil circuit breakers have oil containment pits to prevent ground contamination in the event of oil release from the breaker.

This program (which was originally included in the FBC 2005 System Development and further discussed in FBC's 2012-13 Integrated System Plan) proposes to continue replacing the legacy bulk oil breakers with modern vacuum circuit breakers. The new units are more reliable and require less maintenance than bulk oil breakers. Replacing the breakers also removes the need to install oil containment pits and prevents the associated complication of stranding the oil containment pits when the breakers are removed from service at a later date. Replacement parts are also no longer available for these breakers and often have to be specially fabricated.

This program proposes the replacement of two breakers per year over the period of 2015 to 2019. The breakers will be replaced based on the health index method as evaluated by Metsco Inc. in the report "Oil Filled Circuit Breaker Assessment". This method has been used in the power industry by such utilities as Hydro One, BCTC, ENMAX, Hydro Ottawa, Excelon, Idaho Power, Toronto Hydro and Powerstream.

5.4.3.8 Oil Containment

Legacy substations often do not have oil containment pits to prevent oil release into the environment. Many of the historical substation sites are in locations which would now be considered environmentally sensitive. To reduce the risk of transformer oil contaminating soil, groundwater and nearby waterways, this program will retrofit oil containment pits for legacy substations, either adding containment pits where none currently exist or upgrading containment pits that are considered inadequate. The work will be performed to mitigate stations that pose the highest risk to the surrounding environment. Installation of containment pits for large volume equipment will bring legacy substations up to current standards in this respect.

5.4.3.9 Distribution Substation Transformer Replacements

Aging distribution substation transformers require reinvestment to maintain adequate levels of reliability. This program will address issues arising from aging plant and replace distribution transformers that have reached or are approaching their end of life. Currently, the median age of this group of assets is 28 years. To reduce the risk of service interruption due to poor asset health, distribution transformers will be replaced starting in 2018 at a rate of one every three years. Coordination with growth planning will be pursued to identify areas where voltage conversions can result in station consolidation. Asset health data gathered during regular maintenance and inspections may precipitate advancing or delaying this schedule, and will be consistent with the proposed FBC Asset Management plan. FBC proposed similar projects in the 2005 SDP to replace transformers with condition-related issues. As per order G-52-05, the Osoyoos T2 and Pine Street T1 transformers were replaced in 2006.

5.4.3.10 Minimum Oil Circuit Breaker Replacements

FBC's fleet of Minimum Oil Circuit Breakers (MOCBs) is aging and will require replacement to maintain acceptable standards of reliability. The median and average age of the MOCB asset class is 28 years, with the assets ranging in age from 20 to 44 years old. As this asset class ages, maintenance expertise and spare parts will become increasingly scarce. When minimum oil circuit breakers operate severe stress is put on the operating mechanism. Within FBC's system, these circuit breakers do not necessarily operate frequently; therefore the breakers can continue to provide protection into the future. However, the availability of spare parts and the breakdown of insulation systems in the breakers is a concern. In 2010, a circuit breaker of this type failed violently at the AA Lambert Terminal station; an insulation failure of the operating rod within the MOCB was determined to be the likely cause.

These breakers will continue to be monitored and assessed, and replacement will be carried out in accordance with the FBC Asset Management plan. The Minimum Oil Circuit Breaker Replacement program will replace MOCBs at a rate of two per year starting in 2017 and continuing until 2035.

5.4.4 Transmission Lines Sustainment Capital

The sustainment and replacement activities for transmission line facilities are driven by conditions assessments managed on an eight-year cycle. Every transmission pole is assessed once every eight years to determine the condition of the pole and its attached equipment (conductors, insulators, cross-arms, etc.). If an issue is detected, the deficiency is documented and corrected either as an urgent or future replacement activity. Future year sustainment budgets are developed based on the condition assessments that occurred in previous years. Forecast expenditures are generally based on recent years' actual costs. There are six Transmission Lines Sustainment Capital projects in this Application:

- Transmission Lines Condition Assessment;
- Transmission Lines Rehabilitation;
- Transmission Lines Urgent Repair;
- Transmission Lines Right of Way Easements;
- 38 Line Lake Crossing Assessment and Rehabilitation; and
- 19/29 Line Reconfiguration.

5.4.4.1 Transmission Line Condition Assessment

The transmission line condition assessment program is based on an eight-year cycle of inspecting and testing all FBC transmission line facilities. The program consists of a pole test and treat component and an above ground visual condition inspection. The test and treat component of the program is aimed at the section of pole at the ground level and below and consists of drilling test holes in each pole to identify internal rot and adding pole treatment into the hole to forestall internal rot. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying and grounding) above ground. If an issue is detected during the condition assessment the deficiency is documented and corrected under the following year's transmission rehabilitation budget. The program is managed in an eight-year cycle to levelize both the budget and the resources required.

The estimates for this budget are based on historical information of assessment costs on a per structure basis, adjusted for inflation. The Transmission Line Condition Assessment program is required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and ensure an acceptable level of service is maintained for customers.

In 2014, a somewhat higher number of pole assessments have been identified as compared to future years. This is due to the need to assess the portion of 9/10L between the Christina Lake and Cascade substations which has been deferred from previous years. The prospective costs associated with rehabilitating or rebuilding these lines will be used in evaluating the alternative options available to the Grand Forks T2 addition project.

5.4.4.2 Transmission Line Rehabilitation

The specific rehabilitation projects for various transmission facilities involve expenditures for stubbing poles, replacing poles, cross-arms, guy wires, as well as correcting other defects identified in previous years' assessments. This project is required to address public and employee safety issues, environmental concerns and maintain reliable electrical service to FBC customers. The estimates for this budget are based on historical information of rehabilitation costs on a per pole basis, adjusted for inflation and changes to overhead loading, and knowledge of the transmission lines being assessed and the expected condition of the equipment.

In 2014, there is also some additional carry over work resulting from the assessments that were completed in 2012 and scheduled for rehabilitation in 2013 but were deferred into 2014 and 2015 due to the large scope of work that was unable to be completed under the 2013 rehabilitation budget.

5.4.4.3 Transmission Urgent Repair

The Transmission Urgent Repairs program is required to repair or replace components that are in poor condition and in danger of immediate failure on the transmission system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions or other unexpected reasons that can cause outages or present risks, and must be addressed in an expedient manner. The project is required to address public and employee safety issues, environmental concerns and maintain reliable service to FBC customers.

The planned expenditures for this program are based on a three-year rolling average of historical expenditures from 2010 to 2012, adjusted for inflation. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.4.4.4 Transmission Right-of-Way Easements

This project is required for acquiring rights-of-way and easements for existing transmission facilities that are in trespass on private property. Expenditures for this budget will also address access issues with respect to existing rights-of-way. Many of the transmission lines, when initially constructed, did not have formal road access to sections of the right-of-way. Access is required for ongoing operation and maintenance of these lines.

The planned expenditures for this program are based on a three-year rolling average of historical expenditures from 2010 to 2012, adjusted for inflation. The three-year rolling average method is used to derive this budget as certain variables that can potentially impact this budget remain outside FBC's control. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.4.4.5 38 Line Lake Crossing Assessment and Rehabilitation

The 38 Line Lake Crossing (formerly referred to as the 30 Line Lake Crossing) is a 63 kV line that connects Coffee Creek substation to Crawford Bay substation spanning Kootenay Lake. The lake crossing was first installed in the early 1950s and was rebuilt in 1962 after the towers were sabotaged. The crossing is an 11,300 foot span consisting of a 1.25 inch diameter 91 strand galvanized steel continuous cable. It is supported by steel lattice type towers anchored back using lattice works (integral to the tower) into concrete foundations.

Previous inspections have noted deficiencies involving the paint, concrete, lighting, and marker cones. The last detailed conductor inspection conducted on the lake crossing span was completed approximately 20 years ago. Data from these past inspections is limited in availability with most information provided anecdotally. The inspections focused mainly on the wire integrity and related marker cones with very little comprehensive assessment information having been documented. Completion of the necessary inspection and resulting rehabilitation on the towers and crossing will extend the life expectancy of the existing crossing and defer the need for significant capital expenditures to replace the crossing.

5.4.4.6 19/29 Line Reconfiguration

The 19/29 Line Reconfiguration project was originally applied for in the 2012/2013 Capital Expenditure Plan (CEP). This project was deferred to the next capital plan as a result of the BCUC directive to reduce capital expenditures by $10.5M over the 2012/2013 period. FBC still considers that this project is required.

This project involves creating a permanent tie between 19 Line and 21 Line and salvage of 19 Line from the South Slocan plant switching station to a termination point south of the Passmore substation. 19 Line and 29 Line both originate at the South Slocan switching station and run north in the same right of way corridor until they cross Highway 6 just before the Passmore substation. Presently, the 12.5 kilometer section of 19 Line that runs parallel with 29 Line from

South Slocan Switching station is in very poor condition and requires extensive rehabilitation/rebuild. There is no justification for maintaining both lines that ultimately source the Slocan Valley load radially.

Since 29 Line has recently undergone extensive rehabilitation and is the preferred line to continue to maintain, 19 Line will be salvaged, removing the need to condition assess, rehabilitate, and maintain 19 Line.

5.4.5 Distribution Lines Sustainment Capital

The sustainment and replacement activities for distribution line facilities are driven by condition assessments managed on an eight-year cycle. Every distribution pole assessed once every eight years to determine the condition of the pole and its attached equipment (conductors, insulators, cross-arms, etc.). If an issue is detected, the deficiency is documented and corrected either as an urgent or future replacement activity. Future year sustainment budgets are developed based on the condition assessments that occurred in previous years. Forecast expenditures are generally based on historical costs from recent years' actual costs. There are ten Distribution Lines Sustainment Capital projects in this Application:

- Distribution Lines Condition Assessment;
- Distribution Lines Rehabilitation;
- Distribution Lines Urgent Repair;
- Distribution Line Rebuilds;
- Distribution Line Small Planned Capital;
- Distribution Equipment PCB Compliance;
- Forced Upgrades and Lines Moves;
- Underground Switcher Replacement;
- Underground Cable Replacement; and
- ArcFM Feeder System Audit.

5.4.5.1 Distribution Line Condition Assessment

The distribution line condition assessment program is based on an eight-year cycle of inspecting and testing all FBC distribution line facilities. The program consists of a pole test and treat and a condition assessment. The test and treat component of the program is aimed at the section of pole at the ground level and below and consists of drilling test holes in each pole to identify internal rot and adding pole treatment into the hole to forestall internal rot. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying and grounding) above ground. If an issue is detected during the condition assessment the deficiency is documented and corrected under the following year's Distribution Line Rehabilitation budget. The program is managed in an eight-year cycle to levelize both the budget and the resources required.

The estimates for this budget are based on historical information of assessment costs on a per structure basis, adjusted for inflation. The Distribution Line Condition Assessment program is required to proactively manage the condition and integrity of FBC's distribution line facilities, manage the risk to employees and public safety, and ensure an acceptable level of service is maintained for customers.

5.4.5.2 Distribution Line Rehabilitation

The specific rehabilitation projects for various distribution facilities involve expenditures for stubbing poles, replacing poles, cross-arms, insulators, guy wires, and correcting other defects identified through the previous years' assessments. The Distribution Line Rehabilitation program deals with issues that, while not severe enough to require immediate repairs (in which case they would be carried out immediately under the Distribution Urgent Repairs program), are serious enough that they must be addressed in the year following the condition assessment. This project is required to address public and employee safety issues, environmental concerns and maintain reliable electrical service to FBC customers. The estimates for this budget are based on historical information of rehabilitation costs on a per pole basis, adjusted for inflation, and knowledge of the distribution lines being assessed and the expected condition of the equipment.

5.4.5.3 Distribution Urgent Repairs

The Distribution Urgent Repairs program is required to repair or replace components that are in poor condition and in danger of immediate failure on the distribution system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions or other unexpected reasons that can cause outages or present risks, and must be addressed in an expedient manner. The project is required to address public and employee safety issues, environmental concerns and maintain reliable service to FBC customers.

The planned expenditures for this program are based on a three-year rolling average of historical expenditures from 2010 to 2012, adjusted for inflation. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.4.5.4 Distribution Line Rebuilds

This project involves the replacement of aged and deteriorated equipment on a larger scale than would typically be performed under the Distribution Line Rehabilitation program. Items include rebuilding failing overhead and underground conductor, replacing rotted poles and platforms, replacing leaking transformers, and installing ground grids at ungrounded services, as well as the replacement of copper conductor in areas considered to be a risk to public or employee safety. These deficiencies are identified through condition assessment data, site assessments and normal daily operations. The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FBC customers.

5.4.5.5 Small Planned Capital

This program is similar to the Distribution Condition Assessment and Rehabilitation programs but captures off-cycle work required to keep the distribution lines safe and reliable. Each year operational and safety concerns on the distribution system including storm damage, clearance problems and aging equipment are identified by field staff outside of the normal assessment cycle. Repairs to address these concerns are required to maintain a safe and reliable distribution system. In 2011 FBC expended approximately $50k on the replacement of porcelain cut-outs in high risk areas, and plans to continue these replacements into the future. This is due to the fact that there are areas within the service territory where aged porcelain cut-outs have increasing failures rates with a consequent increased risk to public and employee safety. Also planned for 2014 and 2015 is the replacement of legacy Wye-Delta configured distribution transformers in the service territory as they are also considered a safety hazard. The repairs are generally non-urgent in nature and consequently are not completed under the distribution urgent repair program. They are normally completed within one year of the initial request.

The planned expenditures for this project are based on a three-year rolling average of historical expenditures, adjusted for inflation. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.4.5.6 Environmental Compliance - Distribution Equipment (PCB)

The federal PCB Regulations (SOR/2008-273) came into force on September 5, 2008. As per the regulations, the release of one gram of PCBs into the environment is prohibited. This prohibition applies to all PCBs, without exception and at all times, including during the conduct of activities permitted by the Regulations. Although pole mounted transformers have an in-service exemption until 2025, the one gram release prohibition still applies.

FBC has approximately 41,000 pieces of oil-filled distribution-class field equipment including transformers (pole and pad mount), reclosers and regulators. Currently, the PCB level for approximately 30,000 pieces of equipment has been confirmed through testing or nameplate information. Note that this project excludes any equipment in transmission or distribution substations as they are being addressed through a separate Environmental Compliance (PCB Mitigation) program which is scheduled for completion in 2014 (as discussed above in Section C5.4.3). Proposed expenditures for this project include completion of testing of distribution equipment in 2014 and 2015 followed by initiation of a remediation plan commencing in 2016.

5.4.5.7 Forced Upgrades and Line Moves

This program is required to complete distribution upgrades driven by third party requests. The following are potential situations where upgrades or line moves are required:

- Requests from Governing Authorities (eg. Ministry of Transportation and Infrastructure or municipalities) within the FBC service area to relocate distribution lines located on road allowance or highway right-of-ways to accommodate road widening or improvements.
- Requests to relocate distribution lines where FBC does not have sufficient land rights for the distribution line facilities located on customer property. In each case, alternatives will be considered and the most cost effective solution will be selected. Attempts to negotiate proper land easements are conducted first and are covered under the Distribution ROW Easement budget. If negotiations are unsuccessful, then FBC could be forced to relocate the line as a Forced Upgrade.
- Third party utility requests for upgrade of FBC distribution line plant to accommodate a shared use arrangement.

The planned expenditures for this program are based on a three year average of historical expenditures adjusted for inflation and changes to loadings. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.4.5.8 Underground Switcher Replacement

The Underground Switcher Replacement project was identified in the 20 Year City of Kelowna (CoK) Distribution System Plan 2011-2030 which was produced in 2010. The document was developed by an engineering consultant at the request of the City of Kelowna and continues to be an important guiding document for the sustainment of the portion of FBC's distribution system formerly owned by the CoK. Switches containing SF6 gas are recommended for replacement in an effort to improve safety, reliability, and maintainability. Replacement parts and maintenance are an ongoing concern due to the fact that these switches are located underground and are no longer supported by industry. By the end of 2015, FBC intends to replace all the underground switchers identified as a concern with new standard pad-mount solid-dielectric switchers. An added benefit provided by new switchers is the VFI (Vacuum Fault Interrupter) protection that they offer. Having all customers connected to these VFI protected switches allows for improved protection coordination on the system and quicker and more effective fault location. As well, reliability will be increased as the improved protection coordination will result in faults affecting fewer customers.

5.4.5.9 Underground Cable Replacement

The Underground Cable Replacement project was identified in the 20 Year CoK Distribution System Plan. Main feeder cables manufactured from 1970 to 1981 have been recommended for replacement as they have a higher risk of failure than cables manufactured using more recent methods. While operating the CoK system, FBC has experienced up to four cable failures per year – in some cases resulting in significant extended customer outages. Some cables will be replaced as part of specific growth-driven feeder upgrade projects. Excluding cables that will be upgraded due to growth, there are approximately 15 kilometres of cable which require replacement. This replacement has been scheduled over a ten year timeframe which commenced in 2011. FBC has also experienced problems with some smaller conductor aluminum cables of similar vintage in recent years and proactive replacement of some of these aged cables may also be required. The cable replacement plans are reviewed with the Operations, Planning and Engineering departments to determine which sections of aged cable are the highest priority for replacement.

5.4.5.10 ArcFM Feeder System Audit

With the acquisition of the CoK distribution system, a field audit of the distribution electrical system is required to correct all inconsistencies existing in the ArcFM GIS system as well as to correct field labeling of equipment. This audit is necessary to transfer operating authority of the CoK system to the System Control Center.

The following tasks comprise the main scope of work for the audit:

- Provide unique tags for any primary line switching and isolation devices that do not have tags in the field and update in ArcFM;
- Verify the connectivity and record the unique tags for all primary line switching and isolation devices;
- Update of all connectivity information captured during the field inventory audit into ArcFM;
- Quality assurance of ArcFM updates from field inventory audit;
- Preparation of ArcFM updated single lines for final signoff and transfer to the System Control Centre;
- Transfer of updated ArcFM electronic maps to the System Control Centre and update of the SCADA system; and
- Final signoffs from Operations department and the System Control Centre for transfer of PIC (person in charge) duties.

A verified record of the City of Kelowna primary feeder system will provide multiple benefits which include but are not limited to the following.

- Contributes to the safe operation of the system and ensures compliance with WorkSafeBC Occupational Health and Safety requirements;
- Allows proper load switching for maintenance and upgrades;
- Permits correct switching of loads for in the case of faults and planned outages;
- Aids in troubleshooting faults and unplanned outages;
- Provides an accurate system model to analyze for distribution system planning which improves the accuracy of timing and location for required system upgrades; and
- Ensures that critical operational knowledge is not lost due to employee turnover.

5.4.6 Telecommunications, SCADA and Protection and Control Sustainment Capital

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure the Company's business needs continue to be met. There are four sustainment capital projects included in this Application:

- Station Smart Device Upgrades;
- Backbone Transport Technology Migration;
- Communications Upgrades; and
- SCADA Systems Sustainment.

5.4.6.1 System Smart Device Upgrades

FBC still has a number of electromechanical and electronic relays that do not meet current monitoring and protection standards. Replacement of these relays is a priority and will facilitate Operations, Engineering and Planning efficiencies and enhance system reliability by providing co-ordination of protective devices, accurate information and real time telemetry on system status, faults and other problems and decreasing the need for complex protection schemes. This ongoing sustainment project will update these devices and integrate them into the telecommunications network. In addition, ongoing upgrades to obsolete or failing intelligent electronic devices at substations will occur as needed.

The project will be managed by prioritizing upgrades based on several factors including device malfunctions, obsolescence and vintage, complexity of troubleshooting, probability of failure and the potential for cost and operational efficiencies benefiting system operation and planning.

5.4.6.2 Backbone Transport Technology Migration

The current core data transport technology used by FBC for operational communications is Synchronous Optical Networking (SONET). The current network consists of four SONET rings, comprising about 30 sites supplemented by approximately five lower speed spur links. The balance of FBC facilities are served with several other technologies where appropriate including cellular, private radio, Ethernet, satellite, dial-up, and in some cases are not served at all.

The general trend in telecommunications industry has been to deploy high speed Ethernet/IP technology to replace SONET. This technology has a much lower installed cost, higher bandwidth, is standards-based for interoperability and is more efficient for converged networks (voice plus data) than legacy technologies such as SONET. On the other hand, SONET is often considered to be more robust and deterministic, with lower latency and switching times in the event of failures. The trend in utility communications has been more conservative, and many vendors and utilities are in the early stages of migration to a next generation network. It is expected that the pool of vendors offering SONET equipment will continue decreasing and the operating and capital costs will increase in the future.

The vendor of FBC's SONET equipment is still selling and supporting the equipment, but is expected to discontinue this within the next few years. FBC has been using this equipment since 1996, which is a fairly long time for modern telecommunications infrastructure. Furthermore, FBC staff who have the required knowledge and skill-sets to maintain these legacy systems are at or near retirement age within the next several years. Due to the aforementioned trend towards IP and Ethernet networks, technical schools have not been emphasizing the fundamentals of legacy technologies. This makes replacing these outgoing staff members with new employees with similar skill-sets difficult.

This project will replace FBC's existing SONET network with a new high speed data network supporting all present and anticipated future applications needed to provide safe and reliable service.

5.4.6.3 Communication Upgrades

This ongoing, yearly project will fund upgrade projects for FBC telecommunications facilities. These upgrades will enhance the system operators' ability to monitor the status of the transmission and distribution system and respond to system events. Furthermore, the upgrades will maintain the integrity of the existing infrastructure used to protect the power system, FBC employees and the general public from damages and outages resulting from major system faults and events.

Some FBC telecommunication equipment is near or beyond its designed operational life. Individual components are unreliable, and manufacturers no longer supply spare parts or provide product support. In some extreme cases, equipment can no longer be tested and adjusted regularly because it fails when test systems are operated, resulting in long delays putting equipment back in service.

5.4.6.4 SCADA and MRS Systems Sustainment

The SCADA and MRS Systems Sustainment program will fund annual sustainment projects for Supervisory Control and Data Acquisition (SCADA) software systems and infrastructure located at System Control Centre (SCC) or the Backup Control Centre (BCC) and communications infrastructure directly connecting the SCC to the BCC. Additionally, as Mandatory Reliability Standards (MRS) standards continue to evolve; this program will fund MRS-related system upgrade projects that are deemed necessary to maintain compliance with these standards.

This project also includes sustainment expenditures for assets such as: Survalent Worldview SCADA control software, intrusion detection software, document control software, training management software, electronic security devices, physical security devices and monitors, SCADA servers, SCADA Local Area Network (LAN) and Wide Area Network (WAN) devices, workstations and backup infrastructure.

5.5 *GROWTH CAPITAL EXPENDITURES*

5.5.1 Growth Capital Overview

FBC growth capital expenditures involve projects required to meet customer and associated load growth. Although the growth rate has declined in recent years, FBC is still forecasting moderate load growth over the 2014-2018 period as further discussed in Section C1.

A summary of the 2013 base and forecast Growth Capital expenditures for the 2014 - 2018 test period is provided below.

Table C5-5: Forecast Growth Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Growth Capital						
Transmission, Station & Telecommunications	332	3,187	3,190	-	293	2,928
Distribution	20,306	15,102	14,732	15,589	15,764	16,916
Total Growth Capital	20,638	18,289	17,922	15,589	16,057	19,844

5.5.2 Transmission and Stations Growth Capital

Transmission system capacity requirements are reviewed annually through analysis of actual and forecast demand. Transmission planning studies require a load forecast having a quantitative risk index in order to achieve consistency with industry practice and established reliability standards. To accomplish this, the Company develops both top-down (system level) and bottom-up (distribution feeder level) forecasts of expected peak load and compares these forecasts for consistency. Projects are identified over a twenty year planning period and an options analysis is carried out to select the best overall option from an engineering and financial perspective. Long range planning for the transmission system is required due to the long lead times associated with large infrastructure projects. There are seven Transmission and Stations Growth capital projects identified in this Application:

- 42 Line Meshed Operation;
- Voltage Support in South Okanagan;
- Huth 8kV Capacity Upgrade;
- Glenmore LV Bus Capacity Upgrade;
- Reconductor 52 & 53 Lines;
- Summerland Transformer Replacement
- Spall Breaker House Reconfiguration; and
- Saucier Protection and Metering Upgrade.

5.5.2.1 42 Line Meshed Operation Between Huth and Oliver

This project involves protection and communication system modifications to allow meshed operation of 42 Line between Penticton and Oliver. These modifications will allow FBC to avoid shedding customer load to prevent a voltage collapse for the outage of 40 Line or Bentley T1 over the current twenty year planning horizon. Load shedding or a voltage collapse following a single bulk transmission element outage is not permitted by the BC MRS and hence this project supports FBC compliance with these standards. This project also contains additional benefit as it helps to decrease the loading on 52 Line and 53 Line during contingencies of these lines thus deferring the need for necessary conductor upgrades.

5.5.2.2 Voltage Support in South Okanagan/Boundary During Contingency

This project involves the installation of reactive compensation equipment which includes two 10 Mvar capacitor banks at the Oliver substation in 2014/15 to prevent a voltage collapse or the need for load shedding following single contingencies in the Oliver area. The project is a continuation of the 42 Line Meshed project and is required to continue to meet MRS planning standards and to continue to provide reliable service to the customers in the South Okanagan and Boundary regions.

Even with 42 Line meshed between Huth and Oliver, the combined Oliver, Boundary and 43 Line winter peak load is above the supply capability of 11 Line/48 Line and 42 Line. The amount of load that would need to be shed is approximately 3 MW in 2014 increasing to 9 MW in the winter of 2018. The additional reactive support in the south Okanagan provided by this project combined with the ability to transfer 43 Line load to Princeton during peak load periods will defer the need for capital expenditures beyond the current 20-year planning horizon that would otherwise be required to prevent a voltage collapse following single-contingency outages.

5.5.2.3 Huth 8 kV Transformer Upgrade

The Huth substation provides 8.3 kV and 12.5 kV distribution supply to the City of Penticton municipal utility with the 8.3kV system also having the capability to source FBC load in the area. The City of Penticton load has grown to a point where the existing 8.3 kV transformation is now essentially dedicated to the city load with no surplus capacity for the FBC load, all of which is currently being fed from the West Bench substation. The current 8.3 kV system at Huth is comprised of three single phase transformers of a 1946 vintage that operate in parallel with a three phase transformer of a 1965 vintage. All of these transformers are near end-of-life and have increasing reliability concerns.

The West Bench transformer is forecast to exceed its rated capacity by 2017. FBC contingency planning criteria is also not being met as it is not currently possible to provide adequate backup to the load in the event of a failure of the West Bench transformer.

The project includes the installation of a new 20 MVA transformer at the Huth substation which would allow FBC to offload a portion of the West Bench feeder to the Huth substation. This would allow FBC to continue to provide a reliable supply to the Penticton area load and defer capacity upgrades at the West Bench substation. The upgrade would also increase reliability in the area as the Huth substation would now have the capacity to back-up the West Bench substation in the event of a transformer failure or transmission line outage.

As well, expected development near the Huth substation supports the justification to upgrade the Huth substation as it is in an optimal long-term geographic location to support potential load growth in the area. In comparison, there is currently very little available capacity from the West Bench substation and the area of major load growth is far from the location of the West Bench substation. This project provides numerous benefits and is considered to be the most cost-effective solution to address capacity concerns in the area.

5.5.2.4 Glenmore Low Voltage Bus Capacity Upgrade

The Glenmore substation has two transformers currently supplying seven distribution feeders with one additional feeder planned in the near future. The station has been developed over several decades and portions of the station low voltage bus have inconsistent capacity ratings. A number of disconnect switches in the bus have insufficient ampacity ratings compared to their required capacity. This limits to the ability of each transformer to provide full backup to the substation load in the event of an outage to the other transformer. This project involves upgrading the current 1200 amp rated low-voltage bus and bus tie switches to a consistent 2000 amp rating. This would increase the capacity of the cross bus and tie switches linking all the connected feeders thus allowing maximum load transfers between the two transformers up to their nameplate ratings. This would also provide flexibility for future growth when the station requires the addition of a third distribution transformer as the uprated bus would offer the flexibility to transfer load amongst the transformers.

5.5.2.5 Summerland Transformer Replacement

The Summerland substation transformer sources the City of Summerland municipal utility with the demarcation point at the low-voltage disconnect of the transformer. The Summerland load is forecast to exceed 95 percent of the contract demand limit in 2019. As per the terms of the wholesale supply contract, FortisBC will need to upgrade the capacity of the transformer in order to continue to provide reliable service. By replacing the transformer with the next largest FBC standard transformer (40MVA), substation capacity remains adequate out beyond the 20 year planning horizon. The bulk oil 63 kV breaker within the station will also be replaced with a new SF6 gas breaker consistent with FBC's intent to replace all bulk oil breakers as discussed in section C5.4.3.7 above. An expansion to the existing site to accommodate the required oil containment for the larger transformer may also be required.

5.5.2.6 Reconductor 52 and 53 Lines

This project involves reconductoring the existing 52 Line and 53 Line between the Huth substation and the R.G. Anderson Terminal station with conductors having a higher ampacity rating. This is required to ensure adequate transmission capacity is available to maintain an N-1 level of reliability for a population base of approximately 50,000 residents located in the area along Okanagan Lake from Summerland in the north to Oliver in the south.

The customers in this area are served from the Huth substation via three substations (Trout Creek, Summerland and West Bench radially supplied via 49 Line), the Waterford substation (radially supplied via 47 Line) and the Okanagan Falls and Kaleden substations connected via 42 Line which runs from Huth to Oliver. The combined peak load for these substations is currently forecast to exceed the N-1 capacity of 52 Line or 53 Line in 2020. In the event of failure of either 52 Line or 53 Line the load flow on the remaining circuit is forecast to overload during summer peak conditions in that year. The failure of either of these lines would require shedding/curtailment of load during the summer peak period. Such load shedding is not consistent with FBC planning standards for transmission system performance which do not permit loss or curtailment of load after a single contingency. FBC intends to begin design and construction of the project in 2018 to ensure that the project is complete by the required 2020 in-service date

5.5.2.7 Spall Breaker House Reconfiguration

Replacement of the Spall breaker house was identified in long-term planning reviews conducted by third-party consultants on behalf of the City of Kelowna in 2005 and in 2010. The site was considered to contain aged switchgear that is at the end of its useful life and which poses a significant safety risk to personnel operating it. Both long term plans recommended the replacement of the metal-clad switchgear. However, with the recent purchase of the CoK system by FBC, a more cost-effective solution is to reconfigure the former CoK distribution feeders to be fed out of the adjacent Glenmore substation. This would allow FBC to salvage the Spall breaker house completely. This project will require the addition of a distribution breaker in the existing Glenmore substation and rerouting of the existing distribution cables to the new supply location.

5.5.2.8 Saucier Protection and Metering Upgrade

The following is a background description of the original Distribution Substation Automation Program (as originally described in the CPCN application) that has been ongoing in the FBC system for almost a decade.

> *This program includes the installation of automated systems in distribution substations to gather and analyze data so that decisions can be made more quickly and effectively. It is a multi-year staged Program that focuses on reducing operational costs, preventing power outages and restoring power more quickly when there is a failure, as well as improving the levels of safety to employees and the public.*
>
> *The term "automation" can imply a range of complexity. Systems can consist of relatively simple data logging and monitoring, or they can extend to highly automated schemes that can provide automatic restoration of customer load following system outages. The objective here is to implement solutions for monitoring and control of the system as opposed to the more complex load restoration and auto-transfer schemes. A standard package of protection, monitoring and data collection equipment and system has been developed by FortisBC and is being applied to all new substation construction. The scope of this project involves the installation of these systems to substations that are not currently slated for major upgrade or replacement in the foreseeable future.*
>
> *This Program broadens the integration and use of remote monitoring and control to distribution level substations, including the quality monitoring of lines, transformers and feeders, fault recording and locating, and equipment condition monitoring. It will provide common communication mechanisms for gathering, storing, accessing and analyzing the accumulated data. The Program includes the development of a central data repository, individual equipment installation projects in appropriate substations, and an emergency backup plan.*
>
> *This Program produces many specific benefits. Several will be realized immediately while others will come to fruition as data analysis occurs related to ongoing maintenance and capital replacement projects. One of the immediate benefits is the ability to operate switches remotely, allowing work to commence more quickly, as well as enabling the restoration of power more quickly during conditions of unplanned outage. Another example is the ability to*

meter individual distribution feeder loads, allowing planners to accurately determine electrical consumption at frequent intervals. This information can be used to move load between feeders and increase the efficiency of plant additions, as well as plan for new feeders and substations on a "just in time" basis.

Longer term benefits include more targeted maintenance planning. As an example, power transformer life can be more precisely measured over time, and new transformation can be planned and installed when the life of the unit is about to expire, as opposed to merely using peak load as the replacement indicator. The effect of this may be to extend the life of some transformers without incurring any greater system risk.

As described herein, savings are forecast to be realized in future operating and capital budgets as well as the potential deferral of some capital expenditures. Utilities around the globe have recognized the benefits of these automation systems, which have led to the development of a new industry standard. FortisBC has applied this approach in recently constructed substations and has received the commensurate benefits. To extract the maximum benefits in terms of operating costs, outage reduction and safety, this project proposes to install automation systems in older substations that are not slated for major upgrade or replacement and that will form a significant part of the power system for years to come.

The plan for Saucier substation (formerly owned by the CoK) is to extend the Distribution Substation Automation Program to this location for same reasons this program was implemented at other legacy FBC stations. The switchgear at Saucier is in reasonable condition and is expected to be in service for the foreseeable future. The switchgear has also been identified as requiring the installation of arc flash detection relays which will also be included in the scope of this work.

5.5.3 Distribution Growth Capital

FBC evaluates distribution system capacity on an annual basis. A substation-level load forecast is produced from the bottom-up (distribution feeder level). The substation load forecast attempts to account for expected weather extremes which directly impact winter and summer peak loads. It is a non-coincidental peak forecast used to determine the feeder, transformer and substation infrastructure required to supply all FBC customers during peak demand periods and adverse weather conditions. There are seven Distribution Growth capital projects identified in this Application:

- New Connects System Wide;
- Distribution Small Growth;
- Distribution Unplanned Growth;
- Kaleden Feeder 1 Capacity Upgrade;

- Fault Indicator Installation;
- Grand Forks Terminal Feeder Addition; and
- DG Bell Feeder 4 Addition.

5.5.3.1 New Connects System Wide

This project involves the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in the service area. This project will also fund any forced upgrade costs associated with upgrading FBC facilities to provide service for an extension or drop service.

Capital expenditures are forecast on a gross basis (prior to customer contributions). FBC's customer contribution policy provides customers a capital credit or allowance based on the amount of investment in distribution poles, conductors, and transformers for the rate classes covered in the applicable retail rate. Any investment in poles, conductors and transformers necessary to provide service to a customer in excess of this credit or allowance will be paid as a capital Contribution in Aid of Construction (CIAC) by the new customer. CIAC is a reduction to rate base.

The forecast expenditures for this project are based on a three-year rolling average adjusted for anomalous years, projected customer growth and inflation. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.5.3.2 Distribution Line Small Growth

Small Growth Projects relate to capacity upgrades, construction of distribution feeder ties, and load transfers associated with general load growth. These projects are required to keep pace with normal load growth on the distribution system and to ensure that acceptable standards of service are maintained. These service standards include operation of facilities at or below normal continuous thermal limits, maintaining voltage consistent with Canadian Standards Association (CSA) recommended levels, and ensuring short circuit levels are adequate for safe operation of the electrical system. Capacity increases are also designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system. The Small Growth Projects are defined as distribution capacity related upgrades under $500,000.

5.5.3.3 Distribution Line Unplanned Growth

Capacity upgrades and line extensions are required periodically to keep pace with normal load growth on the distribution system and to ensure acceptable standards of service are maintained.

These service standards include operation of facilities at or below normal continuous thermal limits, maintaining voltage consistent with CSA recommended levels, and ensuring short circuit levels are adequate for safe operation of the electrical system. Capacity increases must also be designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system.

Experience has shown that unforeseen load emergence will require capacity upgrades and voltage correction projects not specifically identified in the capital planning process. The projects typically include service upgrades, voltage regulation, ties to accommodate load splitting, single phase to three phase upgrades and conductor upgrades. Also included is the interconnection of feeders to permit load transfers. As the distribution load grows in different areas, feeder loading becomes unbalanced; the interconnection of feeders allows FBC to optimize loading. This project is required to provide for such items that were unforeseen at the time the expenditure plan was prepared.

The estimates are based on a three year rolling average of historical expenditures from 2010 to 2012, adjusted for inflation. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future year budgets is the most reasonable approach from FBC's perspective.

5.5.3.4 Kaleden Feeder 1 Capacity Upgrades

Kaleden Feeder 1 has a long radial tap from the main feeder that consists of small (No. 2 ACSR) conductor. The current load forecast indicates that even with the two voltage regulators currently on this radial tap, low voltage problems are forecast for 2014. Although the long term plan indicates the need to replace the Kaleden substation with the Central Okanagan Station and the conversion of this radial tap to 25 kV, this project is still required in the interim to ensure adequate customer voltage levels until the voltage conversion is completed. The project consists of reconductoring approximately 3.2km of overhead No. 2 ACSR line to a larger 477 ACSR conductor

5.5.3.5 Fault Indicator Installation

Fault indicator installation was identified in the 20 Year CoK Distribution Master Plan. Fault indicators provide a significant operational benefit by supporting the quick identification and localisation of faults and subsequent repair of faulted cables. Without these fault indicators outage times can be greatly lengthened which negatively impacts customer reliability.

In general, fault indicators should be installed on each primary phase conductor on every switcher node, every junction box node, and on cables leaving feed-through transformers. Since 2005, fault indicators have been installed with new switchers and junction boxes. This program has been initiated as a proactive effort to retrofit fault indicators on all existing equipment in the former CoK service area. The distribution system in this area is primarily underground and much of the system is aged with limited protection and sectionalizing devices. As a result, many faults result in tripping of the entire feeder. Also given the age of much of the cables, faults are common and an ongoing concern. Fault indicators will allow failures to be located much more easily and therefore improve fault isolation and system restoration in a cost-effective manner.

5.5.3.6 Grand Forks Terminal Feeder Addition

The Christina Lake T1 transformer is approaching its nameplate capacity of 5 MVA. Given the relatively small amount of load supplied from this station and the low customer growth rate in this area, FBC has conducted an analysis to determine if offloading the station would be possible using existing system assets and with minimal investment to support a long-term plan.

There are currently two 63 kV transmission lines which run from the Grand Forks Terminal, past the Ruckles substation, past the Christina Lake substation and then back towards Warfield. This project would repurpose a portion of one of these transmission lines as a distribution feeder between the Ruckles substation and the Christina Lake substation. This distribution feeder would then be interconnected to a new distribution feeder constructed out of the Grand Forks Terminal. This arrangement would allow a portion of the Christina Lake area load to be supplied directly from the Grand Forks Terminal. This project would eliminate the need to upgrade the Christina Lake T1 transformer from a capacity perspective until beyond the 20-year planning horizon.

This project is linked to the Grand Forks Transformer Addition project described in Section C5.7.2 below. Following completion of that project, the two 63 kV lines between Grand Forks Terminal and Warfield would no longer be required to provide back supply to the Grand Forks area. Instead, one line would continue to be used to supply the Ruckles and Christina Lake substations and the second line would be repurposed as a distribution feeder. .

This project is consistent with the Company's long-term plan to have a 25 kV express feeder out of Grand Forks Terminal station to offload the Ruckles and Christina Lake substations completely. This project puts the majority of the required line infrastructure in place, but the complete voltage conversion would not occur until Christina Lake substation or Ruckles substation is once again overloaded.

5.5.3.7 DG Bell 4 Feeder Addition

The DG Bell Terminal is the furthest south distribution source in the Kelowna area. There are currently three feeders sourced from DG Bell with two of these feeders supplying all the customers in the upper Mission area of Kelowna. This area of Kelowna is experiencing significant residential customer growth and the current load forecast indicates that there will be need for another feeder to relieve the existing two feeders within the next five years. There is also little backup capacity available for either of these two feeders when either feeder is subject to a planned or forced outage. The addition of a fourth feeder to the DG Bell substation will increase reliability to customers in the south Mission area of Kelowna as well as relieve the load on the other feeders.

5.6 *OTHER CAPITAL*

Other Capital (previously referred to as General Plant) consists of planned capital expenditures for vehicles, metering, business technology and information systems, telecommunications, buildings, furniture and fixtures, and tools and equipment. Expenditures planned for 2014 to 2018 also include regulatory and legislative compliance initiatives. A summary of the 2013 base and forecast Other Capital expenditures for the 2014 – 2018 test period is provided below.

Table C5-6: Other Capital ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Other Capital						
Information Systems	4,271	5,290	6,134	5,791	5,747	5,721
Vehicles	2,360	1,948	1,783	1,749	1,907	1,945
Meters Changes	369	-	71	109	114	118
Telecommunications	166	156	159	162	166	169
Buildings	803	1,044	912	942	961	980
Furniture & Fixtures	110	260	531	87	88	90
Okanagan Long Term Solution	-	120	122	3,800	-	-
Advanced Metering Infrastructure	-	16,765	18,233	583	741	604
Total Other Capital	8,495	26,078	28,449	13,738	10,247	10,162

The following sections provide a brief description of the Other Capital requirements for 2014 - 2018.

5.6.1 Information Systems

FBC's Information Systems expenditures focus primarily 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. FBC relies on a base of core enterprise applications, including SAP (Financial, Human Resources, Project Management and Materials Management), CIS (Customer Information System), 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. FortisBC carefully 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.

There are five Information Systems capital projects in this Application:

- Infrastructure Sustainment;

- Desktop Sustainment;
- Application Sustainment;
- Business Technology Enhancement; and
- Business Technology Transformation.

In an effort to achieve acceptable services levels and security for its internal and external customers, FortisBC puts emphasis on its 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 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 Business Transformation 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 Infrastructure, Desktop and Application Sustainment.

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 FBC does not possess a suitable solution able to satisfy a justifiable 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 maximum benefit and project success. This includes ensuring that competing demands from the various operating business units be supported. As such, the Company has implemented 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.

The Company's PPM provides a standard framework to evaluate projects allowing for the comparison and selection of competing projects. Projects must be aligned to the Company's strategic goals of safety, customer service, reliability and efficiency. Each project is required to demonstrate how it supports the achievement of organizational goals and priorities. PPM compares and prioritizes potential project investments based on the project's contribution to the organization's goals, irrespective of where or when the initiative originated. The priority of each project guides the financial and resource allocation for the portfolio. Prioritization ideally assures projects with the greatest value to the Company will be considered first when allocating finite resources.

PPM determines a Project Portfolio which must be reviewed and accepted by the Business Systems Steering Committee (BSSC). The BSSC consists of the key representatives from both the Energy and Electric Companies namely Environment, Health and Safety, Customer Service, Finance, Operations, Human Resources, External Relations, Engineering Services and Information Systems. There is then Executive oversight on recommended projects and the Portfolio. This activity takes place annually following the corporate budgeting process and in advance of initiation of the targeted fiscal year. Prior to execution, all approved Project Portfolio projects must still acquire formal authorization for capital investment through written justification (business casing) which reaffirms the business value of undertaking the project and validates the assumptions made in the initial establishment of the Project Portfolio.

As a part of further adoption of PPM the Company has developed a Benefits Management Practice to better support the business casing and investment analysis for discretionary, transformational business systems and technology projects. This practice compares the actual benefits achieved from a project against those anticipated (planned) in the business case. The benefits are measured for the entire lifecycle of the business technology investment.

The following projects planned for the period of 2014 to 2018 are required to improve safety, customer service, productivity and efficiency by enhancing functionality and operability.

5.6.1.1 Business Technology Transformation

This project will fund any justifiable business requirement or opportunity in support of safety, customer service, reliability and productivity for FBC's operations. When the Company does not possess a suitable solution able to satisfy the business case, the Company will support the introduction of new business technology, process and training to meet the identified need. As this work is discretionary in nature, funding approval requires business benefits analysis and justification through the Benefits Management practice.

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 transformational projects is to transform the way FortisBC does business in response to customer and business needs resulting in efficiencies and subsequent benefits, while aligning with the Company's business and technology strategy.
The following are currently identified scopes of work that will be pursued through this Business Technology Transformation project.

- Geospatial – This set of work aims to pursue opportunities to align the gas and electric organization in support of asset management and the benefits of that program. This may require additional interfaces, system reconfiguration and process changes.
- Operations Integration – This set of work aims to assess new electronic dispatch capabilities to provide additional dispatching services for FBC. In 2016, it also seeks to introduce an Outage Management System enabling more accurate identification of the most likely source and location of unplanned outages on its distribution system and restore service to customers as quickly as possible. The program will also review operational engineering activities to assess similarities and the potential for consolidating operational business processes between FEI and FBC.
- Knowledge Management – 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.
- Customer Service – Aims to improve customer service through the use of new business systems and processes that enhance customer facing functionality and meet changing market needs.
- Human Resources – Alignment of HR systems for FEI and FBC, combining staff records, payroll function together with skills and competencies.
- Financial reporting - Assess Finance AP Automation and Asset reporting to transform current activities through the re-engineering of accounts payable processes, see improved asset management reporting, audit compliance and enable FortisBC to scale accounts payable operational activity within existing resource limits.
- Asset Management - Improve asset management capabilities through the potential introduction of new technology processes to reduce total cost of maintenance.

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.

5.6.1.2 Business Technology Enhancements

This project will fund any system enhancements that are required during the fiscal year. 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 is of importance to the Company in optimizing decision making. SAP NetWeaver provides data warehousing functionality, a Business Intelligence (BI) platform, and a suite of BI tools that delivers this capability. Relevant business information from productive SAP applications and all external data sources are integrated, transformed, and consolidated in BI with the toolset provided. BI provides flexible reporting, analysis, and planning tools to support the Company in evaluating and interpreting data, as well as facilitating its distribution. Businesses are able to make well-founded decisions, predict future possibilities and determine target-orientated activities on the basis of this analysis. 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 external FBC internet web site, to enhance customer self-service and information availability. Electronic billing options and capabilities will also be enhanced to broaden customer options.
- Enhancements will be made to improve and automate interfaces between the AM/FM mapping system, CIS and the SCADA control system. These interfaces allow for a real time view of the electrical network on a scaled map of the electrical system, visibility of vehicle locations in relation to customers and improved restoration information by relating customers to the electrical network.

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 the enhancements are considered non-discretionary.

5.6.1.3 Infrastructure Sustainment

The Infrastructure Sustainment project 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 budget 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 (over thirty terabytes of disk space in each data centre), 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 2018 due to a number of enterprise infrastructures approaching end-of-life, including telephony, servers, storage and backup equipment.

5.6.1.4 Desktop Infrastructure Sustainment

The Desktop Infrastructure Sustainment project includes Microsoft Windows operating system, Microsoft Office Suite and other job specific hardware and software upgrades for FBC's personal computers (PC) environment. It is a phased approach to keeping approximately 670 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.

This project also includes the costs necessary to replace fax machines, telephones and photocopiers/printers to maintain reliability and compatibility with industry standards. These replacements are also managed on a staged approach based on standard lifecycles. An asset tracking tool is used to track the age of all technology assets at FortisBC to ensure they are replaced in a timely manner and to realize maximum life expectancy without jeopardizing productivity.

5.6.1.5 Application Sustainment

This project will fund the annual sustainment requirements for all FBC applications including CIS, SAP, AM/FM and all other applications used at FBC. 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.

5.6.2 Vehicles

This project involves the replacement and/or acquisition of heavy fleet vehicles, light duty vehicles, passenger vehicles, service vehicles, specialty equipment and off road vehicles necessary to meet the operational requirements of FBC. The planning process for Fleet Services adheres to the Company's objective to provide customer service in a manner which is safe, reliable, cost effective and applies sound environmental practices. FBC currently has 355 units in the fleet. In the past five years, the number of units in the fleet has been stable, averaging 350 units. This trend is forecast to continue over the next five years with planned expenditure being required solely for vehicle replacements.

Many factors are taken into consideration when an actual vehicle replacement decision is made. Factors such as suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, and compliance with regulations, are reviewed when vehicles are near the end of their planned service life. Each replacement decision is evaluated on a unit-by-unit basis.

Electric utilities depend on the availability of specialized, reliable, safe, and efficient vehicles. Deferring these planned vehicle expenditures increases the risk of negatively impacting employee and public safety, degrading service response times and increasing operating costs resulting from excessive repair costs and equipment shortages. As such, the replacement of heavy fleet vehicles, service vehicles, passenger/light duty vehicles, and specialty equipment and off-road vehicles is necessary for the Company to ensure the continued provision of safe and reliable service.

5.6.3 Meter Changes

This project involves the purchase of new revenue metering infrastructure driven by customer growth as well as replacement for metering equipment that fails during the metering compliance or meter re-test program. Metering infrastructure includes meters, current transformers, potential transformers and ancillary equipment.

The AMI project is scheduled for completion in 2015, therefore, FBC is not intending to exchange any meters for compliance purposes during the 2014 – 2018 period. Instead, FBC is only forecasting expenditures for meters and ancillary equipment to cover customer growth, meter damage, and meter failures.

If the AMI project is not approved, FBC will submit an amendment to this application identifying the incremental capital expenditures necessary to address meter compliance and sampling requirements mandated under the Measurement Canada Sampling Plan S-S-06 which comes into effect on January 1, 2014.

5.6.4 Telecommunications

This on-going, yearly project will upgrade general communications systems to support FBC Operations and Network Services, and will improve safety, operational efficiency and emergency response capability.

The Telecommunications budget is used to purchase new or replacement communications equipment in support of field staff. This equipment includes landline equipment, VHF (Very High Frequency) radio communications equipment, and the installation of fibre cabling and wireless systems intended for multiple applications. These installations provide voice as well as data communications as required. This project supports the communications infrastructure needed for FBC to carry out general business operations. The projects have been initiated by Planning, Engineering or field staff and address the need for replacing or supplementing communications systems based on identified deficiencies. This budget does not include any work for communications systems installed specifically for protection and control of the power system.

5.6.5 Buildings

FBC owns and operates 15 different sites with the purpose of providing office, warehouse and yard space within its service territory. The Buildings budget includes projects such as drainage and infrastructure projects to replace septic fields, upgrade storm sewer systems, and add oil intercepts, all of which are intended to remain in compliance with various environmental codes and regulations. In addition, examples of other smaller projects funded by this budget include heating/ventilation/air-conditioning (HVAC) system and washroom upgrades. The Buildings budget also addresses unforeseen issues including items such as breakdowns of HVAC and other building systems.

As per the FBC Access Control Policy and the BC Mandatory Reliability Standards, FBC has a requirement to provide controlled access to building sites to ensure the security and safety of FBC employees and assets. FBC currently operates an access control system installed in 2000 which no longer receives vendor support and has been deemed to have a high risk of failure. In addition, the system has the following security limitations:

- The system has no automation on employee termination. Preset employment end dates cannot be set and instead requires manual processing to check to see if consultants and employees require cancellation;
- The system has no administrator security; and
- The system audit and logging reports are very limited.

As such, replacement of this system is required to ensure that adequate facilities access control is in place.

Furthermore, in order to reduce the occurrences of yard thefts, additional security within FBC yard compounds is required. As such, additional exterior intrusion detection and camera equipment with digital video recording is planned to be added into the access control system during the 2014 – 2018 PBR Period.

5.6.6 Furniture and Fixtures

This project is required for the replacement of furniture that has reached the end of its life cycle, as well as the replacement of fixtures to accommodate changing needs within the organization.

The Company maintains an inventory of furniture at all sites. The condition of the furniture is assessed by placing it in one of three categories (disposal, poor and good). Using this process within the context of the FBC Environment Health and Safety Standard 108, (Section 2.2) *Monitoring the Work Environment*, the capital requirements are determined for each year. Typically chairs are replaced every five years and workstations are reviewed for functionality every eight to ten years.

5.6.7 Tools and Equipment

This budget provides tools which allow employees to do their job safely, efficiently and at a level expected for the business. The Tools and Equipment budget is used to purchase and/or replace tools that have a value greater than $1,000. This budget covers tools and test equipment that is required by the various trades at FBC. New tools are also purchased to improve ergonomics, to meet new equipment needs, and to replace aged test equipment and other items to meet the broad range of operations tasks.

5.6.8 Okanagan Long Term Solution (Land)

Within Kelowna, FBC operates from three facilities located at separate locations including two office buildings which are leased and one office building which is owned by the Company. In addition, FBC uses yard space for outdoor storage of operating equipment at two of these sites. However, FBC continues to be challenged by office space constraints that exist among the three sites. In addition, there remains an opportunity to improve operational efficiency by consolidating the location of office and yard activities and to improve upon a safety concern related to access/egress at the FBC-owned Benvoulin site. As such, the FBC strategy provides for a phased approach with the first phase consisting of the acquisition of the adjacent lot to the Benvoulin site, allowing for the consolidation of yard activities while providing space for a second point of access. Furthermore, expansion of office space at the Benvoulin site would be considered at a later date under a separate approval process. A summary of this project is provided below.

As part of the 2006 Capital Expenditure Plan, FBC requested capital funding of $3.2 million to support the purchase and initial development of 6.55 acres of agriculture land located north of the Benvoulin property, which was approved by Order G-8-06. Unfortunately, FBC was unable to get approval from the Agriculture Land Commission (ALC) to rezone this property. As such the Company did not proceed with the property acquisition.

FBC has completed further analysis of a long term space strategy for the Kelowna area and has determined the following:

- Centralizing FBC Operations at one site will facilitate efficiencies by eliminating the lease cost, the current requirement to drive between the Benvoulin and Enterprise facilities, reduce first aid premiums (each facility has designated first aid personnel), and reduce other ancillary expenditures such as courier and data network costs.
- The current Benvoulin site zoning is Utility for non-farm use and prohibits FBC from selling the property as commercial/industrial zoned property. The existing Benvoulin facility was built in 2003. Disposal of the Benvoulin property would require FBC to remove all buildings and return the land to the Agricultural Land Reserve (ALR) to be sold as ALR land. Considering the age of the facility and the costs associated with removal of existing building, disposal of the Benvoulin property (and subsequent

relocation to a new site) is not a cost-effective consideration to address the space constraints for FBC operations in the Kelowna area.

- The real estate market in the Kelowna area is challenged due to the lack of available large pieces of property as well as the high cost of industrial land (approximately $1 million per acre).
- The purchase of the 6.55 acres of land located north of (and adjacent to) the Benvoulin property is the most cost-effective solution to address the existing space constraints. FBC expects it will be successful getting this land approved for non-farm use by the ALC by offering the right to move other agriculture land not currently in the ALR into the ALR. This purchase would require a change from the original capital funding request of $3.2 million made in 2006 to the current requirement of $3.8 million plus loadings. The additional cost is related to the funding necessary to purchase the rights to move non ALR land into the ALR.

FBC would develop the land in a phased approach by initially servicing the property to allow for additional yard storage and parking. This would allow an immediate reduction in the annual leased costs for yard storage of $110 thousand per year supported by both O&M and Capital funding. The second phase would be to expand the building footprint which would be filed as a separate approval process.

FBC believes this approach is a fair approach to the ALC mandate and provides the company with a cost effective long term solution to support these existing employees.

5.6.9 Advanced Metering Infrastructure

The Advanced Metering Infrastructure (AMI) project consists of the replacement of FBC's existing meters (excepting industrial customers served by the MV-90 metering system) with AMI meters capable of near real-time two way remote communication, as well as the necessary supporting communications infrastructure. An application for a CPCN for the project was filed on July 26, 2012, with the oral phase of the hearing process concluding on March 15, 2013. The AMI project is expected to result in a number of immediate benefits to customers, including savings associated with a reduction in the theft of electricity, operating savings associated with the elimination of the manual meter reading function, and avoidance of costs that would otherwise be incurred to replace approximately 88,000 existing meter to comply with new Measurement Canada compliance sampling and testing requirements (S-S-06). As discussed in Section C5.6.3 above, FBC is not intending to exchange any meters for compliance purposes during the 2014 – 2018 period. If the AMI project is not approved, FBC will submit an amendment to this application identifying an incremental $7.3 million in capital expenditures required to address meter compliance and sampling requirements under S-S-06 during the 2014 – 2018 test period.

It is expected that implementation of the AMI project will result in a rate decrease of approximately one percent over the life of the project. Based on the positive net benefit to customers, FBC believes the project to be in the public interest and expects to receive approval to proceed with implementation of the AMI project. Section C4.18 provides further discussion of the forecast O&M impacts related to the AMI project during the 2014 – 2018 test period.

As discussed in the application for the AMI project, the implementation of the AMI system will result in new sustainment capital costs associated with IT hardware, licensing, and support. These sustainment capital requirements result from the addition of new software such as the meter data management system, the head end system and network management system, and ongoing software licensing and support requirements. The forecast sustainment capital costs for the AMI system were incorporated in the project financial analysis included as part of the application for a CPCN for the project, however a request for approval of these sustainment capital expenditures was not included as part of the capital expenditure request associated with implementation of the project, particularly since these sustainment capital expenditures are only required once implementation of the AMI system has commenced. As such, the sustainment capital expenditures associated with IT hardware, licensing, and support for the AMI system are appropriately included in this application.

5.7 *CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY*

Section 45(2) of the Act provides that a public utility (operating after September 11, 1980) is deemed to have received a Certificate of Public Convenience and Necessity (CPCN) authorizing the construction and operation of extensions to its system, unless the Commission determines that a separate application for a CPCN is required. Since 2005, FBC has filed applications for CPCNs for capital projects that meet the following conditions:

8. The total project cost is $20 million or greater; or
9. The project is likely to generate significant public concerns; or
10. FBC believes for any reason that a CPCN application should proceed; or
11. After presentation of a Capital Plan to FBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application; or
12. The Commission determines that a CPCN application should proceed.

Consistent with these criteria, the Company intends to submit applications for CPCNs during the 2014 to 2018 period for the following projects:

- Kelowna Bulk Transformer Capacity Addition;
- Grand Forks Transformer Addition;
- Ruckles Substation Upgrade;
- Central Okanagan Substation;

- Grand Forks to Warfield Fibre Installations;
- Corra Linn Spillway Concrete and Spill Gate Rehabilitation; and
- Kootenay Long Term Facilities Strategy.

5.7.1 Kelowna Bulk Transformer Capacity Addition

The addition of a new power transformer will be required to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions. Customers in Kelowna and the surrounding areas are currently served by two terminal stations: the FA Lee Terminal Station which contains two 168 MVA 230/138 kV transformers and the DG Bell Terminal Station which contains one 200 MVA 230/138 kV transformer. Following the outage of one of the two existing FA Lee Terminal transformers, the load on the remaining transformer exceeds its emergency overload rating when the total Kelowna area load reaches 369 MW. This condition constitutes a violation of BC Mandatory Reliability Standard TPL-002, which requires that applicable thermal ratings are not exceeded following the loss of a single element. The standard requires that corrective plans must be implemented to eliminate the violation.

The need for additional capacity was identified in past transmission planning studies as being driven by Kelowna area load growth. The need was further advanced with the transfer of the BC Hydro Winfield area load to the FortisBC Duck Lake substation in 2011. The required in-service date for this project (based on then current load forecasts) was 2015 and therefore was discussed in the 2012/13 CEP with the intention to develop a CPCN submission and have all engineering complete by the end of 2013. Since then the load forecast has been revised given actual load data available from the BC Hydro Duck Lake load and the new FortisBC substations constructed in recent years. As well, growth rates have been reduced to reflect current economic conditions. The current load forecast indicates that the need for this project is deferred from 2015 to 2019. FortisBC intends to submit an application for a CPCN for this project 2 – 3 years in advance of the expected 2019 in-service date. Expenditures for this project have a preliminary estimate of approximately $14.5 million. The CPCN will contain a detailed option analysis, information on the recommended solution and a revised project cost estimate (AACE Class 3) and expenditure schedule.

5.7.2 Grand Forks Transformer Addition

Presently, the Grand Forks Terminal station has only a single 161/63 kV transmission transformer. In the event of a forced outage to this transformer, supply to the Grand Forks 63 kV bus can only be re-established via 9 Line or 10 Line from the Warfield Terminal Station. Each of these lines is rated for approximately 25 MVA per line (50 MVA total). During winter peak conditions, the Grand Forks load exceeds the capacity of either 9 Line or 10 Line, and thus both lines need to be operated in parallel to prevent overloads. Both 9 and 10 Lines were originally constructed in the 1920s and much of the poles and wire infrastructure is original to that era. Both transmission lines are in relatively poor condition and experience frequent outages, especially during winter conditions due to snow unloading and tree contacts. FortisBC considers that the installation of a second transformer at the Grand Forks Terminal would be a more reliable and cost-effective solution as compared to the substantial amount of transmission line rehabilitation that will be required. A detailed condition assessment will be completed on both 9 Line and 10 Line and will help confirm the scope of work to be presented in the application for a CPCN, expected to be filed in 2016. Expenditures for this project have a preliminary estimate of approximately $5.9 million; however the estimated expenditures will be subject to further refinement as part of the development of an application for a CPCN and the associated preparation of an AACE Class 3 estimate for the project.

5.7.3 Ruckles Substation Upgrade

The Ruckles substation has numerous condition issues related to geography and aging equipment. The substation is located in a manmade depression and has been subject to flooding during spring runoff on several occasions. Due to the uncertain future of the existing station, it was not included in the recently completed Distribution Substation Automation Project or the Protection Upgrade program. This has left the equipment at the station below standard and with limited availability of replacement parts should any of the protection or metering equipment fail. An options analysis to investigate either rebuilding or relocating the substation is currently being completed and is expected to form the business case for the application for a CPCN, expected to be filed in 2015. Expenditures for this project have a preliminary estimate of approximately $5.9 million; however the estimated expenditures will be subject to further refinement as part of the development of an application for a CPCN and the associated preparation of an AACE Class 3 estimate for the project.

5.7.4 New Central Okanagan Station

In the 2012 Long Term Capital Plan, the Central Okanagan substation was identified as a future new substation to replace the existing Trout Creek, West Bench, Kaleden, and OK Falls substations with one central 25kV substation over several phases. At the present time, the ongoing sustainment of the existing West Bench and Trout Creek substations is considered more cost effective than constructing additional capacity at the new Central Okanagan station, new 25kV distribution lines to the existing sites, and new step down transformers (25kV/8.3kV) at the existing sites. The Kaleden substation however still remains a concern due its age and capacity. Thus, the Central Okanagan Station will still be required however with a reduced scope. FortisBC intends to file an application for a CPCN for the Central Okanagan station in 2017. Expenditures for this project have a preliminary estimate of $24.0 million; however the estimated expenditures will be subject to further refinement as part of the development of an application for a CPCN and the associate preparation of an AACE Class 3 estimate for the project.

5.7.5 Grand Forks to Warfield Fibre Installations

The backbone of the current FortisBC Fibre Telecommunications network consists of company owned fibre and fibre where FBC has secured an Indefeasible Right of Use for direct fibre access. Figure C5-3 outlines the FBC service territory, with the current fibre routes shown in green.

Figure C5-3: Existing FBC Fibre Routes

As is clearly shown, the fibre network is not contiguous end-to-end (there is a gap between Grand Forks and Trail) and FBC does not have any high speed communications facilities linking the Okanagan to the Kootenays. This impacts operational communications as both the main and backup control centres are in the Kootenay region while the majority of the load is in the Okanagan.

FBC proposes to provide this “missing link” between the Okanagan and Kootenay regions by constructing a new fibre optic cable between the Grand Forks (GFT) and A.S. Mawdsley (ASM) terminal stations. This new cable would be constructed on the existing 161 kV transmission line. An application for a CPCN is expected to be filed for this project in 2013. Expenditures for this project have a preliminary estimate of $4.8 million; however the estimated expenditures will be subject to further refinement as part of the development of an application for a CPCN and the associated preparation of an AACE Class 3 estimate for the project.

5.7.6 Corra Linn Spillway Concrete and Spill Gate Rehabilitation

In mid-2011 the provincial government updated the *BC Dam Safety Regulations* to be consistent with the Canadian Dam Association Dam Safety Guidelines. Under the updated regulations dams are now classified under five categories instead of the four categories previously used. A consulting/construction firm was contracted to determine the consequence of failure for Corra Linn which resulted in a reclassification from Very High to Extreme category. As such, FBC's plan of isolation, access, sandblasting and recoating gates has now increased in scope to include:

- Reassessment of the dam's ability to withstand a seismic event
- Secondary power supply added to operate the spillgates
- Refurbishment of gate hoist mechanisms
- Upgrade of structural towers
- Upgrade of spillway gates

As discussed in Section C5.4.2 above, FBC will perform the detailed engineering analysis for this project beginning in 2015. An application for a CPCN for the execution phase of this project is expected to be filed sometime during the 2016 – 2017 period. Expenditures for this project have a preliminary estimate of $21.6 million; however the estimated expenditures will be subject to further refinement as part of the development of an application for a CPCN and the associated preparation of an AACE Class 3 estimate for the project.

5.7.7 Kootenay Long Term Facilities Strategy

FBC currently has five facilities located in the Kootenay region that support operational requirements for the region including: the Trail Office Building, the SCC, the Warfield Complex, the Castlegar District Office, and the South Slocan Generation Site. Two of these locations have buildings that require immediate investment. One location is the South Slocan Generation Site which requires replacement of both the Administration Office and Warehouse due to age and condition issues. The second location is the System Control Centre at Warfield which requires replacement due to recently identified MRS compliance concerns and increased space requirements. Finally, note that the most current condition assessment for the Castlegar District Office has identified that this facility is nearing end-of-life within the next three to five years.

FBC has reviewed the identified facilities issues for the locations discussed above and believes the acquisition of land and construction of a new, centralized regional facility (the Kootenay Operations Centre) to be the most cost-effective solution to address these issues. FBC is currently reviewing the timing and phasing of the project, and plans to file a CPCN application for the project in 2013.

5.7.8 Upper Bonnington Unit 1, 2, 4 Refurbishment

The Upper Bonnington hydroelectric plant is located on the Kootenay River approximately 17 kilometers downstream from the City of Nelson, BC. The first generating plant at Upper Bonnington was constructed in 1905 with a capacity for four generating units. The first two units installed were Units No. 2 and No. 3 which were rated at 5.6 MW. Later in 1916 Units No. 1 and No. 4 were added. Each of these units were rated at 6 MW. This plant with the four units is referred to as the "Old Plant". In 1940 an extension structure was added on the river side of the "Old Plant" to house two additional units, No. 5 and No. 6 which were rated at 15.75 MW each.

In early 2013, Upper Bonnington Unit 3 was dewatered for its annual inspection upon which substantial damage was found around the lower turbine area, including a possibly bent shaft. FBC is currently proceeding with the necessary mechanical repairs to Unit 3, however, based on the vintage and operational history of the remaining three units at the Old Plant, a refurbishment project is required for the continued safe and reliable operation of these units. This refurbishment will ensure that FBC's capacity and energy entitlements as provided for under the Canal Plant Agreement are preserved for the benefit of customers.

FBC is currently reviewing the scope and timing of the refurbishment project, however based on current information the Company expects to file an application for a CPCN in 2015 with commencement of the project in 2016.

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 $1.2 billion investment in rate base assets with a mix of debt and equity, as approved by the Commission from time to time. FBC's capital structure of debt and equity and its allowed ROE will be reviewed as part of the second phase of the Generic Cost of Capital ("GCOC") Proceeding which will take place during 2013. For purposes of forecasting cost of service and revenue requirements in this RRA, FBC has used a capital structure of 60 percent debt and 40 percent equity, which is consistent with Commission Order G-52-05, and an allowed Return on Equity (ROE) of 9.15 percent, effective January 1, 2013. FBC's allowed ROE of 9.15 percent is based on a 40 basis points risk premium, previously established under Commission Order G-52-05, over the allowed ROE for the benchmark BC utility. As part of the first phase of the GCOC Proceeding, FEI was designated as the benchmark BC utility and Commission Order G-75-13 set FEI's allowed ROE at 8.75 percent effective January 1, 2013.

In this Application, FBC has forecast debt and equity financing costs for 2014 through 2018. The 2015 through 2018 forecast amounts demonstrate the expected trends over the PBR Period and will be updated as part of FBC's subsequent RRA filings and Annual Reviews. The equity costs are subject to separate regulatory processes and rates will be amended accordingly to reflect those determinations.

1.1 *FINANCING COST*

Debt financing costs include the interest expense on issued debt, interest expense on forecast new issuances and financing fees. Debt consists of both Long-term Debt and Short-term Debt.

1.1.1 Long-term Debt

1.1.1.1 2013 Long-Term Debt

Included in the forecast interest expense from 2014 through 2018 is the cost of debt associated with the Company's forecast long-term debt issuance of $105 million in the second half of 2013 with a forecast term of 30 years and a coupon rate of 4.25 percent based on the latest forecasts. The proceeds, net of forecast issuance costs of $1.6 million, are expected to be used to repay the draws on the operating credit facility which have been used to finance rate base. Consistent with all other debt issuance forecasts, the amount, term, pricing and timing of this issuance may change from forecast based on market conditions, the Company's credit ratings at the time of issuance and the Company's on-going financing requirements. The 2013 debt issuance will be issued under the shelf prospectus program approved by the Commission in May 2013 pursuant to Order G-74-13 to issue MTN debentures up to an aggregate amount of $300 million. Should FBC issue its 2013 long-term debt at a rate and amount that differs from what has been forecast in Table D1-3 prior to customer rates being approved, the Company will recalculate 2014 interest expense accordingly.

1.1.1.2 2014-2018 Long-Term Debt

The Company has long-term debentures maturing in 2014 and 2016 of $140 million and $25 million, respectively. The Company expects to refinance these two maturities with debenture issuances in both years, which have been reflected in its forecasts and are described below:

- A $100 million debenture has been forecast for issuance in the second half of 2014 with a coupon rate of 4.75% and a term of 30 years. The proceeds, net of forecast issuance costs estimated at $1.3 million as described in Section D4.5.9 along with draws on the Company's operating credit facilities, are expected to be used to refinance of FBC's Series 04-1 5.48% $140 million debenture which matures in November 2014. This 2014 $100 million debenture will be issued under the $300 million MTN debenture shelf prospectus program approved pursuant to Order G-74-13.

- A $100 million debenture has been forecast for issuance in the first half of 2016 with a coupon rate of 5.50% and a term of 30 years. The proceeds, net of forecast issuance costs of $1.3 million as described in Section D4.5.9, are expected to be used to finance rate base and the refinancing of FBC's Series H 8.77% $25 million debenture which matures in February 2016. Whether this forecast 2016 debt issuance will be by way of short form or shelf prospectus will be determined as part of a separate regulatory application closer to the time of issuance.

The long-term debt issuances described above are FBC's forecast at this time and may change in amount, term, pricing and timing based on changes in market conditions, the Company's credit rating at the time of issuance, CPCN capital expenditures incurred outside of the Capital PBR formula and the Company's on-going financing requirements. Changes in debt issuances after 2014 will be reflected in the Company's annual rate setting process during the PBR period.

1.1.1.3 Short-term Debt

FBC obtains short-term funding primarily through the issuance of Bankers' Acceptances and prime lending rate margin loans drawn on its $150 million operating credit facility. The operating credit facility is comprised of a $100 million, three year revolving facility maturing on May 4, 2016 and a $50 million, 364-day revolving facility maturing on May 1, 2014. The operating credit facility provides liquidity to finance its capital program and working capital requirements. Generally the Company targets to repay the draws on the credit facility with proceeds from long-term debt issuance when the balance of the draws approach approximately $100 million in order to embed long-term debt to match the long-lived nature of the Company's assets. The public debt markets generally consider $100 million to be the minimum issue size that allows for a reasonable level of liquidity and therefore more competitive pricing.

1.1.2 Forecast of Interest Rates

FBC 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.

1.1.2.1 Forecast of long-term interest rates

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained. The estimated issue rate for the forecast 2013, 2014 and 2016 debt issues are shown below in Table D1-1. Changes in interest rates after 2014 will be reflected in the Company's annual rate setting process during the PBR period

Table D1-1: Long Term Debt Interest Rate Forecasts

	2013	2014	2016
30 YR GOC	2.75%	3.25%	4.00%
Indicative Spread	1.50%	1.50%	1.50%
New Issue Rate	4.25%	4.75%	5.50%

1.1.2.2 Forecast of Short-Term Interest Rates

FBC's short-term borrowing rate is based on the rate at which it issues Bankers' Acceptances (or the Canadian Dealer Offered Rate or CDOR) plus an Acceptance Fee Rate, and on the Prime Lending Rate. Since CDOR is not forecast by economists, a forecast needs to be derived by FBC; therefore, the Company must first obtain the 3-Month T-Bill rate forecast then convert it to a CDOR forecast. FBC does this by taking the 3 year historical spread between CDOR and the 3-month T-Bill rate which is calculated as 0.27 percent from 2010 to 2012. At the time of filing this RRA, the 3-month T-Bill rate is projected to increase from approximately 1.2 percent in 2014 to approximately 3.5 percent by 2018. The Company then layers on the Acceptance Fee Rate which is 1.0 percent based on the pricing arising from the Company's April 2013 renewal of its operating credit facility agreement. The Prime Lending Rate (estimated at the Overnight Bank Rate plus 200 basis points) is projected to increase from 3.20 percent in 2014 to 5.50 percent by 2018. Based on the pricing arising from the April 2013 extension of the operating credit facility agreement, there is no prime rate margin associated with Prime Rate Margin borrowings. The short-term interest rate forecasts using current information are shown in Table D1-2 below. The forecasts for 2015 through 2018 will be updated as part of the Company's annual rate setting process during the PBR period.

Table D1-2: Short Term Interest Rate Forecasts

	2013	2014	2015	2016	2017	2018
Banker's Acceptances						
3-month T-Bills	0.98%	1.17%	2.03%	2.80%	3.10%	3.48%
Spread to CDOR	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Acceptance Fee Rate	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Bankers' Acceptance (Rounded)	2.30%	2.50%	3.40%	4.10%	4.40%	4.80%
Prime Lending Rate						
Prime Rate	3.00%	3.20%	4.06%	4.79%	5.14%	5.50%
Prime Rate Margin	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Prime Lending Rate	3.00%	3.20%	4.06%	4.79%	5.14%	5.50%
Weighted Average Short-term I	**2.40%**	**2.60%**	**3.50%**	**4.20%**	**4.50%**	**4.80%**

The average short-term rates are determined based on a weighting of 90 percent to Banker's Acceptances and 10 percent to Prime Lending loans.

1.1.3 Interest Expense Forecast

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

Long-term debt interest expense is determined using the straight line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The calculation for short-term interest expense is determined by applying the forecast short-term debt rate, shown in Table D1-3, to the estimated short-term debt balance. The short-term debt balance is the difference between the balance of long-term debt and the required 60 percent total debt used to finance rate base. Also included in the total interest expense forecast are financing fees which consist of standby fees, banking agreement renewal fees, annual lender and agency fees, demand line interest and other minor interest charges such as interest due to customers on outstanding security deposits. An overview of the forecast interest expense for 2013 and 2014 is shown below in Table D1-3:

Table D1-3: Overview of Forecast Interest Expense ($ thousands)

Description of Debt	Maturity Dates	Coupon Rates	2013 Approved		2013 Projection		2014 Forecast	
			Weighted Average Balance	Interest Expense	Weighted Average Balance	Interest Expense	Weighted Average Balance	Interest Expense
			($000s)		($000s)		($000s)	
Long-Term Debt								
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953	25,000	1,953
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672	134,055	7,346
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,600	100,000	5,600
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000	100,000	5,000
MTN Series 2013	30 year est.	*4.25%	65,425	3,108	30,781	1,308	105,000	4,463
MTN Series 2014	30 year est.	4.75%	-	-	-	-	12,603	599
Total Long-Term Debt			690,425	40,325	655,781	38,525	736,658	41,952
Short-term Debt			31,777	1,106	32,218	773	(1,465)	(38)
Short-term Debt rate**			3.48%		2.40%		2.60%	
Financing Fees				946		550		671
Total Long-Term and Short-Term Debt			**722,202**	**42,377**	**687,999**	**39,848**	**735,193**	**42,585**
Weighted Average Debt Rate				**5.87%**		**5.79%**		**5.79%**

*The revenue requirements derived from the approved 2012-2013 RRA considered a 2013 Debt Issuance using a forecast interest rate of 4.75 percent. For purposes of forecasting 2014 interest expense, a more recent interest rate forecast of 4.25 percent has been used, as included in Table D1-1, which is subject to change based on market conditions.

**The 2013 Projection and 2014 Forecast short term debt interest expense is based on the weighted average balance at the forecast short-term rates included in Table D1-2.

The 2014 forecast of interest expense is $42.6 million which is approximately $0.2 million higher than the 2013 approved interest expense and $2.8 million higher than the 2013 Projection interest expense. The increase is primarily driven by the 2014 forecast approved mid-year rate base of which 60 percent is to be financed with debt. The 2014 forecast short-term debt balance is negative in order to deem the overall weighted average debt balance to 60 percent of rate base. It should be noted that the 2013 and 2014 forecast interest rates are still subject to volatility based on global economic factors and market conditions which are beyond the Company's control.

1.1.4 Request for Interest Expense Variance Deferral Account

To avoid potential gains or losses on forecasting interest expense, which are affected by global economic factors and market conditions beyond the Company's control, FBC is requesting approval to establish an Interest Expense variance rate base deferral account. This proposed Interest Expense Variance rate base deferral account would capture the impact on interest expense of short-term and long-term interest rate variances, as well as variances associated with the volume and timing of issuing long-term debt, as compared to what has been forecast for rate-setting purposes. The ability and timing to issue long-term debt is also dependent on the debt markets and are not within FBC's control.

Establishing such a deferral account would be consistent with the Interest Expense Variance deferral account approved by the BCUC for FBC's sister companies, FEI (Order G-7-03), FEW (Order G-35-09) and Fort Nelson (Order G-147-09). In addition, the BCUC had previously approved, pursuant to Order G-58-06, an interest expense variance deferral account established during each of the five years of FBC's 2007 PBR Plan to capture all interest expense variances from forecast. For purposes of the 2014 PBR, any additions to this rate base deferral account would be included in the deferred charges schedule and an amortization term of three years is proposed.

1.2 *ALLOWED CAPITAL STRUCTURE AND RETURN ON EQUITY*

Based on Commission Order G-75-13, which set the allowed ROE for FEI, the benchmark BC utility, at 8.75 percent, FBC has prepared this Application using an interim allowed ROE of 9.15 percent pursuant to Commission Order G-58-06 which established a premium of 40 basis points over the benchmark BC utility for FBC and an equity thickness of 40 percent. FBC's capital structure of debt and equity and its allowed ROE will be reviewed as part of Stage 2 of the GCOC Proceeding which will take place during 2013. FEI's allowed ROE has been set at the allowed ROE of 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 benchmark ROE in years 2014 and 2015. Further, the Commission has directed FEI to file a cost of capital application no later than November 2015 under Order G-75-13, for determination of cost of capital for periods beyond December 31, 2015. FBC could also be affected by this direction for FEI. The outcome of such a proceeding on FBC would be reflected in rates once determined.

1.3 *SUMMARY OF FINANCING AND RETURN ON EQUITY*

FBC 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 FBC during the term of the PBR, and the forecast debt rates represent reasonable estimates based on current market information and the Company's current credit ratings. FBC 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 an electricity service provider, FBC incurs taxes that are imposed by different government bodies. The tax expenses included in this RRA reflect the current enacted tax legislation which was applied in calculating the forecast revenue requirement for the Company.

2.1 *INCOME TAX*

FBC 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, FBC has used the same corporate tax rate forecast of 25 percent 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.

On June 27, 2013, the BC government reintroduced legislation to increase the general corporate income tax rate by 1 percent effective April 1, 2013, however it is not yet enacted. 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 Company is requesting that the increase in corporate taxes will be calculated and captured in the Tax Variance deferral account (as discussed in Section D2.4.1 below) once the change in the income tax rate is enacted.

As approved by Commission Order G-52-05, 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.

2.1.1 Income Tax Forecast

Forecast income taxes are primarily impacted by accounting income before tax and timing differences which generally include capital cost allowance, capitalized overhead, pension and OPEBs, regulatory flow-through deferrals and depreciation and amortization.

In this Application, FBC has forecast income tax expense for 2013 through 2018. The 2015 through 2018 forecast amounts demonstrate the expected trends over the PBR Period and will be updated as part of FBC's subsequent RRA filings and Annual Reviews.

2.2 PROPERTY TAX

Property taxes are forecast to increase 7 percent in 2014 with the addition of the City of Kelowna distribution assets as well as changes in revenues from electricity 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. Over the period 2015 to 2018, property taxes are forecast to increase on average, approximately 2 percent per year.

In this Application, FBC has forecast property tax expense for 2013 through 2018. The 2015 through 2018 forecast amounts demonstrate the expected trends over the PBR Period and will be updated as part of FBC's subsequent RRA filings and Annual Reviews.

2.2.1 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.

FBC 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.

2.2.2 Property 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 FBC 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, etc.
4. Taxes based on Revenues: Section 353 of the Local Government Act require "utility companies" to pay 1 percent of revenues in lieu of taxes that would otherwise be paid on improvements specified in legislation other than buildings. For FBC, revenues only include those earned from electricity consumed within the specific municipality.

2.2.3 Request for Property Tax Variance Deferral account

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. In this application, consistent with FEI practice, FBC seeks approval for deferral treatment of property taxes as they are driven primarily by legislation, market values of properties and/or political programs outside the control of the Company. Variances between the property tax amounts forecast in rates and actual amounts paid will be captured in the Property Tax Variance account. For purposes of the 2014 PBR, additions to this account have not been forecast and FBC is requesting approval for these variances to be accumulated in this rate base deferral account and amortized over a three year period.

2.3 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 FBC 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. FBC, 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.

2.3.1 PST incurred in 2013

With the re-introduction of PST as of April 1, 2013, FBC recognized the resulting revenue requirement impacts and implementation costs for the transition back to PST in the HST Removal or Reform Variance Deferral account which was approved pursuant to BCUC Order G-110-12. FBC has included $0.4 million as an addition to the deferral account in 2013, of which $152 thousand relates to revenue requirement impact of reinstating PST, and $250 thousand relates to PST conversion costs.

Table D2-1 below provides a summary of the total addition to the approved deferral account. It includes the determination of revenue requirements associated with PST incurred for 9 months in O&M, meters and capital and the resulting impact on O&M, earned return (cost of debt and cost of equity) and income taxes.

Table D2-1: Deferral of 2013 PST Impact ($ thousands)

Line No.	PST Estimated Expenditures for nine months ended December 31, 2013		2013 Forecast
1	O&M		135
2	Meters		20
3	Capital		580
4	Total PST		735
5			
6	Revenue Requirements Impact (derived from above)		
7	O&M (Row 1)		135
8	Earned Return (Derived from Rows 2 and 3)		23
9	Income Tax Expense (Derived from Rows 2 and 3)		(6)
10	Revenue Requirements impact to be deferred	(a)	152
11			
12	Total 2013 PST Impact deferred		
13	PST conversion costs	(b)	250
14			
15	Total addition to deferral account	(a)+(b)	**402**
16			

The Company is seeking approval to amortize this deferred cost over one year beginning January 1, 2014.

The above PST impact on 2013 O&M for nine months is $135 thousand; however for purposes of rebasing 2013 O&M to determine the 2014 forecast 2014 O&M, a full year of PST in the amount of $180 thousand has been incorporated in Section B6.2.4. Similarly, PST has been incorporated in capital project estimates for 2014 and onwards in Section B6.2.5.

2.4 *TAX ISSUES*

2.4.1 Request for Tax Variance Deferral Account

At any time, the Company can face uncontrollable changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed, all of which are out of the Company's control. The Company is seeking an Tax Variance deferral account to capture and accumulate variances from forecast, as referenced in Section D4.3.7, resulting from 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.

The proposed Tax Variance deferral account would also accumulate any required compliance costs, including changes to information systems.

Establishing this deferral account would be consistent with the Tax Variance deferral account approved by the BCUC for FBC's sister companies, FEI (Commission Order G-141-09) and FEW (Commission Order G-138-10). Similarly, FBC was previously approved, pursuant to Order G-58-06, to defer tax variances resulting from changes of Acts of legislation or government regulation, during each of the five years of FBC's 2007 PBR Plan.

For purposes of the 2014 PBR, additions to this account have not been forecast and FBC is requesting the Commission to approve any variances to be accumulated in this rate base deferral and amortized over a one year period.

2.4.2 Discontinuation of Net of Tax Treatment for Pensions and OPEBs

FBC records the difference between amounts funded by ratepayers for pensions and OPEB and amounts actually paid out by the Company in a deferral account, on a net of tax basis. The net of tax basis for pension and OPEBs was previously approved by Commission Order No. G-52-05.

FBC accepts that amounts funded by ratepayers through both pension and OPEBs through the collection of actuarially-determined expense amounts in rates, but not yet paid out by the Company, should be included in Prepaid Pension and OPEB liability deferral accounts. It also follows that any amounts funded by the Company in advance of being funded by ratepayers would also be included in the Prepaid Pension and OPEB liability deferral accounts.

In the past, the Prepaid Pension and OPEB liability deferral account have been treated on a net-of-tax basis instead of adjusting for the difference between the expenses and the contributions as a timing difference in the calculation of income taxes. FBC is proposing to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense.

FBC is proposing to discontinue the net-of tax treatment on the prepaid pension and OPEB liability deferral accounts for a couple of reasons. Firstly, the Prepaid Pension and OPEB liability deferral accounts are not amortized into rates in a manner like other deferral accounts subject to net of tax treatment pursuant to BCUC Order G-52-05 whereby both the deferral balance and the tax effect are amortized into rates. Rather than being amortized, the prepaid pension and OPEB liability deferral accounts balances change based on the amount of employee benefit expenses recognized and contributions paid in each year. As such these employee future benefit deferral accounts are not drawn down in the same manner as other deferral accounts and their related net of tax deferral balances. Secondly, discontinuing the net of tax recognition on these employee future benefit deferral accounts would be consistent with the treatment approved by the BCUC pursuant to G-141-09 for FEI.

In summary, FBC has included the pension and OPEB funding differences in deferral accounts. The existing net-of-tax balances of the pension and OPEB will be carried forward as a starting point for 2014, but future additions to both accounts will be on a pre-tax basis with the timing of tax deductions recognized in the calculation of income tax expense. FBC requests approval to expand the prepaid pension and OPEB liability deferral account to also include pension funding differences, and include the additions to this account in rate base on a pre-tax basis.

2.5 *CONCLUSION*

FBC will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies. The tax expenses included in this Application reflect the current enacted tax legislation that has been applied in calculating the PBR Period forecasts for FBC.

3. ACCOUNTING POLICIES

This section describes the Company's current and anticipated accounting policies over the PBR Period, the financing of deferrals, a net of tax accounting change, an overview of the depreciation methodology and negative salvage, and the Company's updated capitalized overhead study.

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 FBC'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. FBC, along with 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, FBC 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. FBC 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. FBC, in conjunction with Fortis Inc. and its subsidiaries, 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 FBC, in conjunction with Fortis Inc. and its subsidiaries, 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 FBC, 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, FBC 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 FBC 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. FBC has provided this reconciliation in FBC's 2012 BCUC Annual Report Appendix A. This reconciliation provides a link back to Canadian GAAP which existed prior to 2012. However, FBC 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 and the financial schedules included in Section E. Given these developments, FBC does not see any need to continue with the reconciliation and believes that the US GAAP accounting changes for FBC should be treated the same as any other accounting policy change that has been previously implemented and communicated in previous applications. For these reasons, FBC is requesting, as part of this Application, to discontinue this US GAAP to Canadian GAAP reconciliation starting with the 2013 BCUC Annual Report. FBC would still continue to provide the reconciliation between the regulated financial schedules and the external financial statements prepared under US GAAP and is proposing to only eliminate the Canadian GAAP reconciliation.

Other than the financing of deferral accounts described further in Section D3.2, one accounting-related change which is not specifically related to adopting US GAAP has been requested effective January 1, 2014, as follows:

3.1.1 Discontinuation of Net of Tax Treatment for Pension and OPEBs

FBC records the difference between amounts funded by ratepayers for pensions and OPEB and amounts actually paid out by the Company in a deferral account, on a net of tax basis. The net of tax basis for pension and OPEBs was previously approved by Commission Order No. G-52-05. In the past, the Prepaid Pension and OPEB liability deferral account has been treated on a net-of-tax basis instead of adjusting for the difference between the expenses and the contributions as a timing difference in the calculation of income taxes. FBC is proposing to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense. For purposes for forecasting rate base for 2014 to 2018, the FBC has discontinued applying the tax effects to changes in Prepaid Pension and OPEB liability deferral accounts.

3.2 *DEFERRAL ACCOUNT FINANCING*

In this application FBC proposes changes in the treatment of certain of its deferral accounts to earn both an equity and debt return. This change will increase consistency of treatment among the FortisBC Utilities and consistency with the notion of funding regulated expenditures. The proposed treatment recognizes the appropriateness of both rate base and non-rate base deferral accounts and is consistent with the treatment of deferrals by FEI.

In its Decision accompanying Order G-110-12 regarding FBC's 2012-13 RRA, the Commission ordered a number of deferral accounts to be excluded from rate base and to attract financing of debt only (Weighted Average Cost of Debt (WACD) or short term interest rates, as directed), based on the Commission's determination on page 105 which stated that "current period charges are not "investments" which attract a capital return, they are deferred operating costs/current period expenses which, as noted above, in the Panel's view, should not attract rate base rate of return". As a result, there now exist a number of instances where deferral accounts of like characteristics and purposes attract different rates of financing, being Weighted Average Cost of Capital (WACC) (included in rate base) or WACD or short term interest (excluded from rate base).

Commission Order G-110-12 revealed that the Commission and the Industrial Customer Group suggest that it is only appropriate for capital assets to attract a rate base rate of return. The distinction is not valid and FBC disagrees with this concept as it is an inconsistent principle for several reasons:

In its response to G-110-12 dated September 5, 2012, FBC stated that:

> *"there is no distinction to be drawn between deferrals and capital in terms of the utility's financing costs or its right to a fair return. In both cases, the utility incurs a cash expenditure in one period and recovers the cash from ratepayers in a future period. To compensate the utility for the time lag between the expenditure and its recovery, the capital or deferral, as the case may be, is either included in rate base or attracts AFUDC to mimic a rate base return. Similarly, if operating expenses are incurred in the same period that they are recovered from ratepayers (through current period O&M) then the utility calculates an allowance for working capital which is included in rate base to compensate for the timing of expenses within the year. Therefore it is incorrect to draw a distinction between capital and operating costs based on the nature of the expenditures; in all cases the utility is compensated for the time lag between when expenditures are incurred and when they are recovered."*

The distinction made by the Commission in the G-110-12 decision is not consistent with the BCUC's approved treatment of FBC's deferral accounts prior to 2012 and is also not consistent with the treatment of deferred accounts for FEI. FBC submits that the treatment arising from G-110-12 is incorrect, for the reasons explained above, and that the proper treatment of deferral accounts is, in the majority of circumstances, rate base inclusion, or, if excluded from rate base, financing at the WACC rate. In support of this request, FBC notes three recent decisions by the Commission:

- Order G-163-12 dated October 30, 2012 regarding an application by FBC and FEI for *Approval to Implement an On-Bill Financing Two-Year Pilot Program* confirmed that the financing rate applied to the non-rate base deferral accounts was the AFUDC rate;
- Order G-66-13 dated April 26, 2013 regarding FEVI's *Application for Approval of a Deferral Account in Connection with a Development Agreement between FortisBC Energy (Vancouver Island) Inc. and Pacific Energy Corporation* confirmed that the financing rate applied to the non-rate base deferral accounts was the AFUDC rate; and
- Order G- 56-13, the Commission determined that allowing the proposed AFUDC return on the Greenhouse Gas Reductions (Clean Energy) Regulation expenditures while recognized in non-rate base deferral accounts is consistent with the treatment allowed when these same expenditures are transferred to rate base.

Additionally, the Commission has had a consistent practice of approving FBC's deferral expenditures and credits in rate base with a rate base rate of return for many years. The anomaly is the deferral financing treatment pursuant to the 2012-2013 RRA Decision Order G-110-12 and it is not clear as to how the economic substance of such deferral expenditures differs in 2012 and 2013 as compared to prior years.

Further, deferral expenditures or credits should attract a rate base rate of return. In its Order G-110-12, the Commission in making its decision appears to have relied on differentiating a return based on whether items are operating costs or capital costs. The following excerpt is from the Decision:

> "*Normally, a utility, whether a Crown corporation or shareholder-owned, is not entitled to receive a return on operating costs or current period charges but simply recovery of those amounts from its ratepayers, assuming recovery is otherwise justified.*"

What this reasoning fails to recognize is that the moment an item is placed into a deferral account for future recovery or refund; it ceases to become an "operating cost" or "current period charge". It has now become akin to a capital item in that costs are being incurred in one period and not being recovered from ratepayers until a future period. As FBC discussed in its response to G-110-12 above, even operating items that are expensed and recovered within the same test year receive a rate base return through the working capital component to the extent there is a time lag in their recovery during the year.

It is not relevant whether an item was originally of an O&M nature or a capital nature, because the nature of the expense has been changed by recording it into the deferral account. Allowing deferrals to attract a rate base rate of return recovers the costs associated with the timing difference when there is an outlay of funds and when those costs are recovered from ratepayers. A rate base rate of return is the only logical and consistent approach to be applied; providing consistency between those deferrals that are in rate base and those that are held outside of rate base.

It should also be noted that Commission Order G-110-12 directs a variety of financing cost calculations to be applied to a variety of different deferral accounts, some of which were in rate base and others outside of rate base. This decision decreased the transparency of deferral account balances and increased the complexity of accounting and tracking of deferral accounts that had not previously existed prior to 2012.

FBC can also look to the deferral accounting financing principles applied in other jurisdictions. As part of the Alberta Utilities Commission (AUC) Decision 2010-309 (July 6, 2010) for FBC's sister company, FortisAlberta Inc.'s (FAI) 2010-2011 Distribution Tariff Phase 1, the AUC elaborated on the financing of deferred debt issue costs to summarize its position how all deferral expenditures should be financed, as follows:

> *"similar to tangible assets, these costs are capitalized and recovered through amortization charges over a period of years. This creates an intangible or financial asset that is effectively a long-term receivable to be collected over time from customers. Since necessary working capital is a part of rate base, the change indicated by FAI to classify this intangible asset as rate base rather than working capital does not affect the revenue requirement. The Commission considers that a deferred debt cost is a rate base asset that must be financed like any other rate base asset. Such an asset should be financed,*

like any other component of rate base, using the weighted average cost of capital and should not be considered to be financed by debt alone."

The position by the AUC on financing of deferral expenditures in combination with the BCUC's decisions previously referred to, other than Order G-110-12, support FBC's position that deferred expenditures should be included in rate base., and if held as a non-rate base deferral, such deferral costs should appropriately attract WACC.

Consistent with FEI's practice as described in Appendix F5 of FEI's 2014 – 2018 Multi-Year PBR Plan application, FBC's recommendation for rate base versus non rate base treatment depends on the timing of the deferral account request. If FBC is able to forecast balances for deferral accounts and include them in revenue requirements, then that is the preferred treatment.

In situations where the rates for a particular year have already been set and costs need to be recorded in a deferral account, the Company will, where warranted, request approval for a non-rate base deferral account attracting WACC until such time as rates are re-set under the next revenue requirement or during the annual review process of a PBR, and the account will be transferred to rate base.

In the case of deferral accounts for the preliminary engineering of capital projects that will be the subject of CPCN applications, the account would remain outside of rate base, attracting WACC, until the project commences, whereupon the balance will be transferred to Construction Work in Progress.

Consistent with the Uniform System of Accounts, items that are recoverable from customers but not included in rate base (such as Work in Progress or non-rate base deferral accounts) are afforded WACC treatment so that the utility is afforded the opportunity to earn a fair return on costs prudently incurred to provide service to customers.

3.3 *DEPRECIATION RATES AND METHODOLOGY*

The depreciation expense calculated for 2014 to 2018 reflects the depreciation rates approved as part of the 2012-2013 RRA through Commission Order G-110-12. The approved depreciation rates are applied on a straight-line basis to the opening utility plant in service balance. These depreciation rates are based on the updated 2011 Depreciation Study which was included as part of the 2012-13 RRA. Consistent with the recommended approach to update depreciation rates every 3 to 5 years, FBC proposes to 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.

3.4 *NEGATIVE SALVAGE*

FBC's forecast depreciation expense for 2014 to 2018 included in this Application has not included a provision for negative salvage in rates. For 2014, FBC does not propose a change in accounting policy and intends to continue its current accounting treatment of asset removal costs, which are charged against accumulated depreciation as they are incurred, as opposed to pre-collecting estimated net negative salvage during the asset's estimated useful life. FBC will assess and revisit the inclusion of a provision for negative salvage in depreciation rates at the time the next depreciation study is performed.

3.5 *SHARING OF SERVICES WITH FEI*

Since 2010, FBC and FEI have been sharing common resources starting with the sharing of the Executive and Board of Directors. More recently, the sharing of resources between FBC and FEI has continued as the organizations streamline operations and processes. Effective January 1, 2014, the sharing of costs between FBC and FEI will be incurred under the Amended and Restated Mutual Shared Services Agreement included as Appendix F1.

In this Application, sharing of resources between FBC and FEI, except for the Executive and Board of Directors discussed below, 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 charge. As mentioned earlier in Section A3, given the evolving nature of integration efforts between the electric and gas businesses, the traditional timesheet allocation approach continues to be the appropriate approach to allocate the majority of shared costs between the two organizations.

Pursuant to 2012-2013 RRA Decision Order G-110-12, Board of Director costs were approved for allocation among FBC and FEI on the basis of the Massachusetts Formula for 2012 and 2013. 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. The Massachusetts Formula results in an approximately 23 percent allocation to FBC of the shared Board of Director and Committee costs for 2013. Consistent with the allocation methodology approved for Board of Director costs, FBC requests approval to apply the Massachusetts Formula allocation methodology for Executive costs effective January 1, 2014.

3.6 *FBC'S CODE OF CONDUCT (COC) AND TRANSFER PRICING POLICY (TPP)*

FBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP) are in place to establish business practices to be followed when conducting transactions between FBC and Non-Regulated Businesses (NRB). An NRB is an affiliate of FBC not regulated by the Commission or division of FBC offering non-regulated products and services. The COC and TPP are relevant and applicable to those transactions summarized in Appendix C4 Related Party Transaction Report. There are significant positive benefits of contracting FBC personnel to FPHI under the provisions of the COC and TPP, both in terms of incremental revenue to the regulated utility and labour force enrichment.

The COC and TPP were updated in 2009 and approved by the Commission in Order G-5-10A. The processes currently in place and the independent compliance reviews conducted annually by FBC's Internal Audit have been effective in providing a sufficient level of assurance to ratepayers, stakeholders and the Commission. Based on current and expected transactions with NRBs, both the COC and TPP are expected to continue to provide appropriate direction and rules to govern the interaction of FBC and NRB during the proposed PBR term. As such, FBC does not propose any changes to the existing COC and TPP for this RRA. Should there be updates required to the COC or TPP during the PBR term, the Company will do so as part of FBC's RRA filings and Annual Reviews during the PBR period.

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 practice and in accordance with the BCUC Uniform System of Accounts prescribed for Electric Utilities, charges a certain portion of total operating and maintenance costs (O & M) to capital.

In the 2012-2013 RRA the Company proposed that the overheads capitalization rate remain at 20 percent of O&M during the 2012 and 2013, which was accepted by the Commission, but with the following directive at page 72 of Commission Order G-110-12:

> *"For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time."*

Effective January 1, 2012 FBC adopted US GAAP as its financial reporting framework in order to continue application of rate-regulated accounting through the application of ASC 980 *Regulated Operations (ASC 980).* Additional guidance regarding capitalized overhead is provided by the BCUC *Uniform System of Accounts Prescribed for Electric Utilities as well as* the Federal Energy and Regulatory Commission (FERC) *Uniform System of Accounts.*

The Company adopted US GAAP due to the uncertainties surrounding rate regulated accounting associated with the transition in Canada to IFRS.

The Company engaged KPMG to perform a review of the overhead capitalization methodology and resulting overhead capitalization rate under US GAAP with consideration of ASC 980, the results of which have been included as Appendix F3 (2013 Overheads Capitalized Study) to this Application.

KPMG found that there is:

> *"No single regulatory guideline, statement or source exists that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes the types of indirect costs (i.e. those related to capital projects that have not been directly charged to those capital projects), that should be considered for capitalization for purposes of regulatory and financial reporting. There is limited guidance both from regulators and in U.S. GAAP in this area. Therefore, variations in practice exist due to the limitations of the available framework and the capitalization policies approved by the relevant utilities' regulators. Nonetheless, this topic has been the subject of discussion and comment and a body of evidence exists on the topic."* (Appendix F3, Section 1, Page 4)

and,

> *"KPMG finds the FBC Survey-based capital cost allocation methodology… to be a reasonable basis for capitalization of costs related to capital activities that have not been directly charged to capital projects (i.e. overhead* capitalization*). These methodologies are consistent with internally generated evaluation criteria and practice established by the external guidance (referred to in this report), in particular the requirements of U.S. GAAP under ASC 980 Regulated Operations."* (Appendix F3, Section 1, Page 5)

The 2013 Overheads Capitalized Study reviewed two methodologies for estimating a reasonable overheads capitalized rate. The 2013 Overheads Capitalized Study provides details of the two estimating methods - a Survey-based Model and a Mathematical Model. The Survey-based Model suggests a 15 percent rate while the Mathematical Model yielded a 17 percent rate.

FBC's current capitalized overhead is calculated by applying the overhead capitalization rate of 20 percent to O&M expense (O&M net of direct charges to capital and other non-O&M accounts and direct loadings). Capitalized overhead is then ultimately charged on a pro rata basis to the appropriate capital assets.

An external survey was also conducted by FBC to review the applied overhead capitalization rates across the United States and Canada. This survey can be found in Appendix A on page 39 of the 2013 Overheads Capitalized Study. FBC management reviewed a total of 15 organizations that have issued publicly available information on their level of capitalized overhead. Of these 15 utilities, 11 are Canadian based and 4 are U.S. based.

The results of the survey show that there is a significant level of variation in the capitalized rates across the utilities industry in North America due to various factors including:

- the financial reporting framework (IFRS versus US GAAP),
- the volume of capital activities and size of those entities (the capital intensity or ratio of capital expenditures to total expenditures),
- whether the entities are in gas distribution, hydro generation, nuclear, coal or other forms of power production, and
- the capital overhead cost allocation methodology used.

(Appendix F3, Section 8.6, Page 36)

A summary of the rates noted in Canada for certain utility entities which are applying US GAAP is as follows:

Table D3-1: Comparison of Overheads Capitalized Rates

Utility	Jurisdiction	Accounting Framework	Overheads Capitalized Rate
Heritage Gas	Nova Scotia	U.S. GAAP	59.2%[48]
Enbridge Gas	New Brunswick	U.S. GAAP	44.8%
Enbridge Gas	Ontario	U.S. GAAP	19.8%
AltaGas	Alberta	U.S. GAAP	16%
Union Gas	Ontario	U.S. GAAP	15%
Hydro One Networks Inc.	Ontario	U.S. GAAP	9%
Pacific Northern Gas	British Columbia	U.S. GAAP	4%

In the 2013 Overheads Capitalized Study KPMG made the following observations (Appendix F3, Page 39):

[48] 2010 actual

"*The survey's main findings regarding utility overhead capitalization in U.S. and Canada are:*

- *Among the utilities surveyed both in United States and Canada there is no single or common methodology for allocating indirect costs to capital.*

- *Utilities mostly use direct allocation, cost drivers and time (effort) studies for capitalization of indirect costs, which is a similar approach to the survey-based model.*

- *The capitalization rates range between 4% and 60% of O&M costs.*

- *A study of 18 Canadian and U.S. utilities by Black and Veatch for Hydro One concluded that capitalization rates in Canada and the U.S. had an observed median of 19% and the range of overhead capitalization rates varied from 5% to greater than 50%."*

On page 75 of Commission Order G-110-12 the Company was also directed to:

> *"Accordingly, the Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year."*

The Company met with Commission staff on two occasions to discuss the draft results of the KPMG study and the Company's recommendation that the overheads capitalized rate remain at the current 20 percent of O&M based on the following conclusions:

a) The FBC rate is reasonable and within the range of the capitalization rates approved for other Canadian utilities across various regulatory jurisdictions;

b) 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 20 percent of O&M, and

c) As illustrated in Table D3-2 the Company is expecting forecast regular capital expenditures (which include Costs of Removal, exclusive of Capitalized Overheads, Direct Overheads, and AFUDC) for the period 2014 – 2018 to remain at levels that are generally consistent with or higher than the 2010 – 2013 period. In addition the Company intends to submit CPCNs for 7 known major projects as discussed in Section C5.7 so the total level of capital expenditures will greater than those forecast in Table D3-2.

Table D3-2: Actual and Forecast Regular Capital Expenditures ($ millions)

	Actual			Projection	Forecast				
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Regular Capital Expenditures	55,036	48,452	42,091	65,609	75,176	70,435	54,681	53,028	56,960
Average 2010 - 2013									52,783
Average 2014 - 2018									62,056
Average 2010 - 2018									57,935

In conclusion, the Company is requesting that the current capitalization rate of 20 percent be approved by the Commission and remain at that same rate over the PBR term.

3.8 *DIRECT OVERHEAD*

The Company charges a recovery of supervisory and administrative costs that are not directly charged to specific capital projects but are directly attributable to Transmission and Distribution (T&D) capital projects referred to as direct overhead loading. The purpose of the direct overhead loading is to allocate costs that relate to T&D capital projects specifically rather than having those costs included in the corporate capitalized overhead and allocated to Generation or other non-T&D capital projects.

This methodology was introduced in the 2004 Revenue Requirements Application. A primary reason for this approach is due to the administrative burden associated with charging labour time and costs to individual projects. Instead, some direct costs are charged to a direct overhead loading pool. A mechanism is then used to charge the cost to individual projects on a prorated basis. Although it is possible to direct charge every cost to capital projects, this allocation mechanism is a much more efficient approach. A more detailed explanation of the process is found in the 2013 Overheads Capitalized Study Appendix F3, Section 6, Page 18.*"*

Each department estimates of the amount of time by position and expenses that should be charged to T&D projects via the direct overhead methodology. For example, a Construction Foreman might estimate that 25% of their time would be charged to the standing order. All of the costs are totalled to determine the direct overhead cost pool. The direct overhead loading rate is simply the ratio of the total direct overhead cost pool to the total unloaded T&D capital costs. The costs that are included in the direct overhead recovery are deducted from the respective department O&M budgets prior to determining the O&M subject to the capitalized overhead rate.

Pursuant to the 2012-2013 RRA the Commission issued the following Directive on page 77 of BCUC Order G-110-12 in regard to Direct Overhead:

> *"Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification."*

KPMG was retained by FBC comment on the direct overhead loading in conjunction with the overhead capitalization study referred to in Section D3.7 above.

KPMG has reviewed the Company's treatment of the direct overhead loading and provided the following opinion as follows (Appendix F3, Section 1, Page 5):

> *"KPMG finds the FBC direct overhead loading methodology, as detailed in Sections 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities…"*

In addition, per the following, KPMG confirmed that there is no duplication of costs capitalized by the direct overhead and capitalized overhead methodologies (Appendix F3, Section 8.2, Page 29):

> *"This direct overhead loading process does not result in a duplication of the level of overhead which is capitalized, as the evaluation of the capitalized overhead rate is conducted with these direct overhead loading costs excluded from the remaining corporate cost pool being evaluated."*

The Company is of the opinion that the direct overhead methodology be continued over the PBR term based on the following:

a) There has been no material change in T&D operations since the 2012-2013 RRA that would require a change to the direct overhead methodology, and

b) As was previously illustrated in Table D3-2 above the Company is expecting forecast regular capital expenditures (which include Costs of Removal, exclusive of Capitalized Overheads, Direct Overheads, and AFUDC) (including CPCN's) for the period 2014 – 2018 to remain at levels that are generally consistent with or higher than the 2010 – 2013 period

In conclusion the Company has been using the direct overhead loading methodology since 2004 in order to charge costs directly attributable to T&D capital projects in a more efficient manner than direct charging and expects to continue to do so for term of the PBR. Direct overhead loading does not duplicate those costs indirectly attributable to capital and charged to capital via the capitalized overhead rate.

3.9 SUMMARY OF ACCOUNTING POLICIES

This section has provided the rationale behind FBC's position on various accounting policies which included US GAAP, net of tax accounting for employee future benefits, financing of deferral accounts, depreciation methodology, negative salvage, sharing of services, transfer pricing policy, capitalized overheads and direct overheads. These items have all been reflected in the financial schedules attached in Section E of this Application, in the calculation of rates for 2014 and in the forecast of rates in for 2015 to 2018.

4. DEFERRAL ACCOUNTS

FBC utilizes both rate base and non-rate base deferral account, which are described in this section.

4.1 *DEFERRAL ACCOUNT FINANCING*

In this application FBC proposes changes in the treatment of certain of its deferral accounts to increase the consistency of treatment among the FortisBC Utilities as was discussed in Section D3.2. The proposed treatment recognizes the appropriateness of both rate base and non-rate base deferral accounts and is consistent with the treatment of deferrals by FEI.

4.2 *RATE BASE DEFERRAL ACCOUNTS*

FBC has considered the following factors with respect to continuing existing deferral accounts and in seeking deferral account treatment for different matters:

- Maintain as rate base deferral accounts, or resume rate base treatment of, those previously approved accounts that continue to provide benefits as appropriate to customers and the utilities[49];
- Create new mechanisms to address uncontrollable or non-recurring matters appropriately;
- Discontinue the use of certain deferral accounts that are no longer required.

FBC classifies its deferral accounts according to the seven categories described in Table D4-1 below.

Table D4-1: Deferral Accounts Providing Benefits to Customers and the Utility

Deferral Account Category	General Purpose & Description
Energy Policy	• Captures the costs of FBC's PowerSense programs and initiatives to promote energy efficiency for customers. • 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.

[49] In its Decision attached to Order No. G-7-03 in referencing the approval of individual deferral accounts for FEI, 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, the FortisBC utilities have continued to employ deferral accounts previously approved by the Commission.

Deferral Account Category	General Purpose & Description
Revenue and Power Supply	• Captures un-forecast variances in revenue and power purchase expenses caused by factors such as fluctuations in purchased power costs including BC Hydro rate changes, and the impacts of weather and other changes to load. • Also includes revenue deferred for the purpose of rate stabilization. • Decreases the variability in rates caused both by such factors as fluctuations in purchased power costs and the significant impacts of weather and other changes to load. • Deferring the 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 variability.
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.
Preliminary and Investigative Charges	• Costs incurred in determining the feasibility of projects for utility services. Upon commencement of the projects, the costs are transferred to the capital project. • Deferring the investigative costs of capital projects eliminates volatility in O&M expense and ensures that only amounts actually expended are taken into rates.
Cost of Regulatory Compliance	• 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, and incremental labour (such as overtime for bargaining unit employees).
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature.
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.

FBC's deferred charges are subject to net-of-tax deferral accounting pursuant to BCUC Order G-52-05 which stated the following:

> *"The Commission believes that a consistent treatment of deferral accounts is warranted to ensure proper matching of costs and benefits. The Commission Panel directs that all deferred charges (excluding preliminary and investigative costs charges transferred to capital projects) be treated using net-of-tax deferral accounting commencing in 2005".*

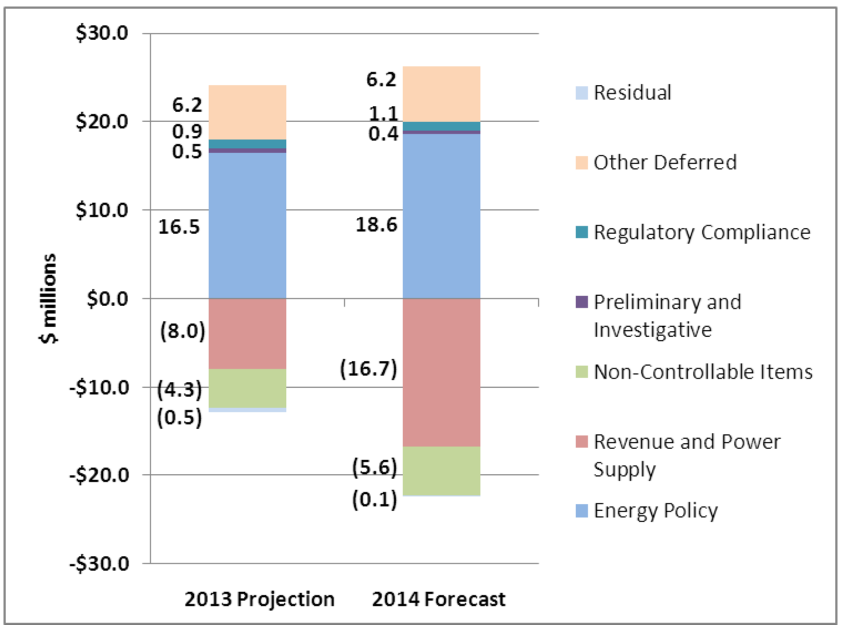
Accordingly, forecast changes in deferred charges from 2014 to 2018 have been recognized net-of-tax with the following exceptions. As described in further detail in Section

D3.1, FBC is proposing to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense.

Similarly, Preliminary and Investigative Charges are either charged to capital or expensed and are not tax-effected

The forecast mid-year balance of unamortized deferred charges in rate base for FBC is approximately $2.4 million in 2014 as balances in the Demand Side Management and debt issue costs are largely offset by the deferred Power Purchase Expense and the Rate Stabilization Deferral Mechanism Account described in Section D4.3.1 below. The forecast mid-year balances range from $(2.5) million to $16.6 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: 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 FBC's other currently approved accounts, the original rationale that justified establishing the accounts. They are expected to continue to accumulate new amounts during the PBR Period, and should remain in place. A summary of all existing and proposed rate base deferral accounts can be found in Appendix F4. For a discussion on non-rate base deferral accounts, please refer to Section D4.7 below.

4.3 NEW ACCOUNTS

FBC is proposing to create new deferral accounts to capture the costs of regulatory proceedings, revenue impacts of BCUC decisions, and other non-controllable items, as detailed in this section. The establishment of deferral accounts for the non-controllable items in this section will result in a consistent treatment, including amortization periods, of those similar items deferred by its affiliates that are also regulated by the BCUC.

4.3.1 Rate Stabilization Deferral Mechanism (RSDM)

In this application FBC proposes a RSDM to mitigate the variability in revenue requirements during the PBR period. This variability is primarily attributed to 2012-2013 deferral variance flow-throughs which reduce revenue requirements in 2014, as shown on line 29 of the Revenue Requirements Overview schedule[50], combined with increases in power supply costs, as described in Section C2.

The RSDM would take the form a deferred credit to be recognized in rate base during 2014 and amortized over the PBR Period to reduce rate variability over the five years of 2014 – 2018. Based on FBC's current forecasts of revenue requirements over the PBR Period, an initial credit of $22.6 million would yield annual rate increases of 3.3 percent, exclusive of the items listed in Section A1 (that is, future projects to be approved by way of applications for CPCNs and impacts arising from the Commission decision regarding the current Stage 2 Generic Cost of Capital proceeding), and changes to forecasts of those cost accounts that are not formula-driven, as presented during each Annual Review in order to set rates for the following year.

The forecast use of the RSDM is shown in Table D4-2 below.

Table D4-2: RSDM Account Balances (Net of Tax) 2014 – 2018 ($ thousands)

	2014	2015	2016	2017	2018
Additions(Amortization)	22,567	(2,430)	(10,112)	(7,100)	(2,925)
Year End Balance	22,567	20,137	10,025	2,925	-

The RSDM has, in part, been proposed in response to Commission Order E-15-12 issued in May 2012. This Order accepted the WAX CAPA for filing as an energy supply contract pursuant to section 71 of the Utilities Commission Act and requires FBC to develop a rate smoothing proposal for the Commission's approval either through a separate submission or with the next Revenue Requirements Application. While the direction to propose rate stabilization was so ordered, the combination of both the WAX CAPA and the 2012-2013 deferral variance flow-throughs are the catalyst to implement the RSDM for the term of the PBR.

The RSDM is also consistent with a rate stabilization mechanism previously approved by the BCUC for FBC. Pursuant to Commission Order G-134-99, a Rate Stabilization Adjustment of

[50] Section E, page 296

$32.9 million at January 1, 2000 was instituted in order to ensure that tariff rates would not increase more than 5 percent annually during the period 2000 through 2002.

The rate stabilization effect obtained by this proposed deferral is similar in nature to the Rate Stabilization Deferral Account (RSDA) approved by the BCUC for FEVI in Commission Order G-140-09. The RSDA was established in 2010 with the intent of capturing the excess of revenues received vs. the actual cost of service, to be amortized into cost of service in setting future rates. The RSDA recorded revenue surpluses in the years 2010 through 2012; starting in 2013 the accumulated surplus is being utilized to manage rate increases that would otherwise have occurred.

4.3.2 Earnings Sharing Mechanism Deferral Account

In Section B6.4, FBC proposes an Earnings Sharing Mechanism (ESM) similar to that contained in its 2007 PBR Plan. Fifty percent of earnings above or below the approved ROE will be recorded in a deferral account for refund or recovery from customers in the subsequent year.

5.7.9 BC Hydro Application for New Power Purchase Agreement with FortisBC Inc.

On May 24, 2013, BC Hydro filed an application for approval of a new long term Power Purchase Agreement (PPA) with FBC. As a party to the PPA, the Company will actively participate in the regulatory process, including responding to Information Requests, and will incur costs, the amount of which will depend on the scope and type of process determined by the Commission. FBC proposes to amortize the costs of this proceeding over one year in 2014.

4.3.3 Generic Cost of Capital Revenue Requirements Impact

On November 28, 2011, the Commission issued a Preliminary Notification of Initiation of Generic Cost of Capital (GCOC) Proceeding to all regulated entities. Order G-20-12, set down a GCOC Proceeding taking place in two stages. Order G-187-12 made interim, effective January 1, 2013, the current ROE and capital structure for regulated utilities (excepting BC Hydro) that rely on the benchmark utility to establish rates. Stage 1 concluded with the issuance on May 10, 2013 of Order G-75-13., setting the ROE for the benchmark utility at 8.75 percent, effective January 1, 2013 and resulting in a decrease in FBC's ROE from the interim 9.90 percent to 9.15 percent.

The regulatory timetable established for Stage 2 by Order G-77-13 contemplates that a decision will be rendered in early 2014.

FBC has recorded the 2013 revenue requirements impact of the Stage 1 decision in a deferral account and proposes to amortize the amount in 2014. This account will also be used to record and flow through any further revenue requirements impacts as soon as reasonably possible following a Stage 2 decision, taking into account the effective date of the Stage 2 order.

4.3.4 Insurance Expense Variance

Insurance expenses may differ significantly from the levels forecast, primarily due to changes in economic factors outside of the Company's control, including copper theft. Global events can influence insurance expense and the impact of this type of event cannot be reasonably incorporated into insurance forecasts, therefore a deferral account to capture the difference between actual and forecast costs of insurance premiums is appropriate.

Insurance market volatility when it comes to estimating premiums year over year results from 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 and the most recent Calgary flooding catastrophe) can have a significant impact on insurance rates anywhere from a 10 percent to 100 percent increase and 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. In fact, in the FEI 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. For purposes of the 2014 PBR, additions to this account have not been forecast and FBC is requesting approval for these variances to be accumulated in this rate base deferral account and amortized over a one year period.

4.3.5 Interest Expense Variance

To avoid potential gains or losses on forecasting interest expense, which are affected by global economic factors and market conditions beyond the Company's control, FBC is requesting approval to establish an Interest Expense Variance rate base deferral account, as described in further detail in Section D1.1.5. This proposed Interest Expense Variance rate base deferral account would capture the impact on interest expense of short-term and long-term interest rate variances, as well as variances associated with the volume and timing of issuing long-term debt, as compared to what has been forecast for rate-setting purposes. For purposes of the 2014

PBR, additions to this account have not been forecast and FBC is requesting approval for these variances to be accumulated in this rate base deferral account and amortized over a three year period.

4.3.6 Tax Variance

At any time, the Company can face uncontrollable changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed. This account will capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction. The account would also accumulate any required compliance costs, including changes to information systems. For purposes of the 2014 PBR, additions to this account have not been forecast and FBC is requesting approval for these variances to be accumulated in this rate base deferral and amortized over a one year period.

4.3.7 Property Tax variance

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. In this application, consistent with FEI practice, FortisBC seeks approval for deferral treatment of property taxes as they are driven primarily by legislation, market values of properties and/or political programs outside the control of the Company. Variances between the property tax amounts forecast in rates and actual amounts paid will be captured in the Property Tax Variance account. For purposes of the 2014 PBR, additions to this account have not been forecast and FBC is requesting approval for these variances to be accumulated in this rate base deferral account and amortized over a three year period.

4.3.8 2014-2018 Annual Reviews

As part of the proposed PBR Plan, FBC will hold an Annual Review for the purpose of setting rates for the upcoming year. The costs of the Annual Review will be recorded in a deferral account, which the Company proposes to amortize into rates in the subsequent year.

4.4 *CHANGES TO AMORTIZATION PERIOD OR CONTENT OF ACCOUNTS*

4.4.1 Demand Side Management (DSM)

The Company is seeking approval for expenditures of $2.25 million after tax ($3.0 million before tax) for its DSM programs in 2014, increasing to $2.4 million ($3.3 million before tax) in 2018. As set out in Appendix H, this reduction in DSM expenditures from 2012 and 2013 levels reflects a marked reduction in the Long Run Marginal Cost (LRMC) which is used in the TRC Benefit/Cost evaluation of DSM measures and programs. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation.

The lower program expenditure level will result in lower average customer rates over the test period by 0.2%-0.4% annually.

FBC is proposing a change in the amortization period of past and future DSM expenditures from 10 years to 15 years. This change in amortization is appropriate for the weighted measure life of FBC's DSM portfolio, and is also consistent with the amortization treatment of BC Hydro's DSM expenditures, as approved by Order G-77-12A. The rationale for changing the amortization period is provided in Appendix H.

4.4.2 On-Bill Financing (OBF) Pilot Program

In accordance with Commission Order G-163-12, FBC created a non-rate base deferral account attracting AFUDC to capture, on a net-of-tax basis: the OBF Pilot Program costs. Pursuant to Order G-163-12 FBC will transfer the balance of this account to rate base effective January 1, 2015. The Company proposes to change the amortization period of this account from 10 years to 15 years, consistent with the proposed amortization period of its DSM expenditures beginning January 1, 2015.

4.4.3 2014-2018 PBR Application

FBC will incur costs in 2013 related to the current PBR Application. 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. This account was established by Order G-110-12; consistent with past practice, FBC requests approval to amortize these costs over a period which represents the period covered by the PBR Application, in this case five years.

4.4.4 Pension and Other Post-Employment Benefits Expense Variance

In this Application, FBC is requesting approval to extend the amortization period of this account from the currently approved 3 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 recently accounting valuation done at December 31, 2012, the EARSL for the defined benefit pension plans is 10 years and the EARSL for OPEBs is 13 years. Using the weighted average of the 2014 through 2018 forecast pension and OPEB expenses, as shown in Table D4-3 below, the average EARSL amortization period is 11 years[1]. This amortization period will be used for the term of

[1] (10 years x 60.8%) + (13 years x 39.2%) = 11.2 years (rounded to 11 years)

this PBR and may be adjusted in the next revenue requirement application based on the calculation of EARSL at that time.

Table D4-3: Weighting of FBC Pension and OPEB Expense

	Pension Expense	OPEB Expense
2014 Forecast	8,342	3,958
2015 Forecast	7,379	4,067
2016 Forecast	6,407	4,185
2017 Forecast	5,559	4,312
2018 Forecast	4,833	4,448
Total	$ 32,520	$ 20,970
Weighting	60.8%	39.2%

4.4.5 City of Kelowna Acquisition Customer Benefit

This account captured the 2013 Customer Benefit resulting from FBC's purchase of the utility assets of the City of Kelowna, including an adjustment to the 2013 Revenue Variance account. FBC requests approval to amortize the $2.6 million Customer Benefit in 2014.

This account will be discontinued effective January 1, 2015.

4.4.6 City of Kelowna Acquisition Legal and Regulatory Costs

Order C-4-13 approved the deferral of up to $0.5 million in closing, regulatory process and legal costs related to the acquisition of the utility assets of the City of Kelowna. FBC requests approval to amortize these costs in 2014.

This account will be discontinued effective January 1, 2015.

4.4.7 2014 – 2018 Capital Expenditure Plan

Preliminary engineering costs for the preparation of FBC's capital expenditure filing (Section C5 of this Application) was approved by Commission order G-110-12[51]. FBC is requesting approval to amortize the costs of the regulatory capital plan over two years beginning in 2014.

4.4.7.1 2012 and 2013 Deferred Expenditures

On December 12, 2012, FBC applied to the Commission for approval to establish certain deferral accounts. The application was consistent with FBC's long-standing practice of requesting approval of deferred accounts in the year the expenses are incurred. Commission Order G-23-13 dated February 8, 2013 approved the establishment of a non rate base deferral account containing the following expenditures but set down the appropriate carrying costs as a

[51] Referred to as the 2014-2015 Capital Expenditure Plan

matter for this current application. FBC requests approval for financing of the non rate base account at the Company's WACC rate during 2013, and further seeks approval to transfer the balance in each of these subaccounts (Sections 4.4.8 to 4.4.13) as at December 31, 2013 to rate base on January 1, 2014.

4.4.8 BCUC Generic Cost of Capital Proceeding

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 reviewed 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. The GCOC Stage 2 will apply the generic benchmark utility in the determination of an appropriate ROE and capital structure for each affected utility.

FBC will incur costs related to the Stage 1 and Stage 2 processes in 2013 and 2014, and proposes to amortize the account over two years beginning in 2014.

4.4.9 BCUC Inquiry into the Mandatory Reliability Standards (MRS) Program

The Commission established by way of Order R-72-12 an Inquiry into the BC MRS Program to review potential changes to the Rules of Procedure and to establish processes for assessing severity and risk for violations under the BC MRS Program. FBC proposes to amortize the costs of participating in the Inquiry in 2014.

4.4.10 Kettle Valley Expenditure Review

By Order G-36-12, the Commission established a written public hearing process to review the prudency of the expenditures on the Kettle Valley Distribution Source Project approved by Order C-5-06. Commission Order G-47-13 dated April 3, 2013 approved the Kettle Valley Expenditures, with the exception of $65,734.[52] The Company incurred approximately $0.1 million ($0.2 million before tax) primarily for legal expenses, for this regulatory process. FBC seeks approval to amortize the deferred amount in 2014.

4.4.11 Transmission and Self-Generating Customer Rate Design

On November 14, 2011 the BCUC issued Order G-188-11 regarding a complaint by Zellstoff-Celgar Limited Partnership (Celgar) concerning the failure of FBC Inc. and Celgar to complete a General Service Agreement and FBC's Application of Rate Schedule 31 Demand Charges.

[52] The Commission also directed FBC to hold the amount of $50,000 in a non rate base, non interest bearing deferral account for recovery from ratepayers when and if this portion of the substation site becomes used and useful. See Section D4.7.1.

The Order included certain directives that will require public consultation, cost of service, and rate design efforts on the part of the Company. Order G-188-11 initiated a separate regulatory process, FortisBC Inc. Guidelines for Establishing Entitlement to Non-PPA Embedded Cost Power and Matching Methodology. This process was not anticipated at the time the original deferral account for the Transmission and Self-Generating Customer Rate Design was established. On April 13, 2012, FortisBC filed its draft guidelines for the level of entitlement to non-BC Hydro PPA embedded cost power by eligible self-generating customers, and a proposed methodology for notionally matching sales to non-PPA resources. This process involved seven interveners and required a number of submissions to the Commission that resulted in Commission Order G-202-12. An Application for new rate schedules for self-generating customers, transmission customers, and a standby rate for Celgar was filed with the Commission on March 28, 2013 and is an active process at the time of this submission.

FBC expects to incur expenditures of $0.1 million net of tax for consultation and rate design activities and the regulatory review of these issues. FBC seeks approval to amortize the deferred amount in 2014.

4.4.12 Mandatory Reliability Standards Audit

WECC, as administrator of BC's MRS Program, conducted its first audit of FBC in 2012, since the program's inception in 2009. The scope and approach for the MRS audit in terms of depth, detail and evidence requirements was far more onerous than had been anticipated by FBC, or indeed than had been experienced in internal or external audits previously. Approximately 50 employees were involved in the audit process, requiring more than 8,700 labour hours, and over 500MB of information was provided to the auditors during the audit period. Eight consultants/contractors were also engaged to support the effort. The audit covered approximately one-third of the requirements for which FBC is responsible. Of those requirements, about 20 percent were in mitigation during the audit and were therefore not formally reviewed.

Of the approximate costs incurred during the audit process, about $231,000 of internal labour costs were charged to Operating and Maintenance (O&M) Expense as budgeted in the 2012 Revenue Requirements. The balance of the audit expenses, were recorded in a deferral account ($0.4 million net of tax). FBC requests approval to amortize the deferred amounts in 2014.

4.4.13 Mandatory Reliability Standards – Operating and Maintenance Expense 2012-2013

FBC's approved O&M Expense for 2012 and 2013 included $1.2 million in each year to maintain full and auditable compliance with the BC MRS. The scope of work related to MRS includes efforts to monitor and maintain security systems, field maintenance, ongoing self audits, participation in BCUC audits, ongoing training and participation in user groups, and evaluating impacts on changes to existing standards and the adoption of new standards.

During 2012 the Company recorded an additional $0.3 million before tax of costs in the deferral account; in 2013 the incremental cost required to ensure that MRS compliance is maintained are estimated to be $0.9 million before tax.

Since the adoption of MRS in BC, the effort and costs associated with MRS are transitioning from capital expenditures to maintaining compliance (in 2010, 100 percent of the effort was capital-related, in 2011 approximately 70 percent was operating expense). As BC's MRS environment continues to evolve, new and amended standards, external processes, and an increasing complexity of reporting requirements necessitate constant oversight and evaluation. Also contributing to increased O&M costs is the completion of the mitigation plans required to achieve initial compliance with standards, which were largely exempt from self-reporting and self-certification while under mitigation. 2013 is the first year in which the Company will not have a significant percentage of the requirements under mitigation, which increases the requirements for "24/7" compliance monitoring.

The costs of MRS compliance directly result from legislation enacted in British Columbia between 2009 and 2012. The Company believed at the time of filing its 2012-13 RRA that it had reasonably estimated the necessary costs of compliance, but there was no provincial experience on which it could rely for calibration or verification of its estimates, nor was it able to obtain comparables from its counterparts in other jurisdictions. The increased expenditures are necessary and prudent if FBC is to provide the services required under the BC MRS Program, as described in more detail in Section C4.10

The Company requests approval to amortize the deferred amounts in 2014.

4.5 *INFORMATION UPDATES*

4.5.1 Revenue Variance

Order G-110-12 approved the revenue variance deferral the majority of which are attributable to weather related load variances, customer usage rate variances and customer count load variances. Order C-4-13 approved an adjustment to the revenue variance arising from the from the City of Kelowna acquisition. FBC will amortize the additions approved by Order C-4-13 during 2014.

4.5.2 On-Bill Financing (OBF) Participant Loans

In accordance with Commission Order G-163-12, FBC created a new 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 OBF Pilot Program and the applicable interest charges and recoveries. FBC 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 (the loan repayment period) until the account is fully recovered.

4.5.3 Kelowna Bulk Transformer Capacity Addition Project

The Company undertook preliminary engineering for the Kelowna Bulk Transformer Capacity Addition project in 2011 and 2012, based on forecast load growth at the time of the Company's 2012-13 RRA. Since that time, updated load projections have deferred the need for this project from 2015 to 2019, as is explained in Section C5.7.1.

Commission Order G-110-12 directed that preliminary and engineering deferral accounts with costs accruing beyond a three year period should be amortized into rates unless a CPCN application or an expenditure schedule is filed. A CPCN application is expected to be filed for this project in 2016, with construction to begin in 2017. Accordingly, FBC will amortize the balance in this account in 2014.

This account will be discontinued effective January 1, 2015.

4.5.4 Section 71 (Waneta Expansion Capacity Agreement) Application

FBC's application for approval of the Waneta Expansion Capacity Agreement (WAX CAPA) was approved by Order E-29-10 on September 23, 2010. Deferred legal, consulting, regulatory and other costs associated with the WAX CAPA and related agreements and the regulatory approval are being amortized over a period of 3 years beginning in 2011 in accordance with Commission Order G-184-10.

The deferred costs also include expenditures arising from an application for reconsideration of E-29-10 filed by the Industrial Customers Group on November 10, 2011. Ultimately the WAX CAPA was accepted for filing as an energy supply agreement pursuant to section 71 of the Act. FBC will recover the balance of the costs in this account during 2014.

This account will be discontinued effective January 1, 2015.

4.5.5 Negotiation of a New Power Purchase Agreement between BC Hydro and FBC

The Company is amortizing the forecast costs of negotiating the new Power Purchase Agreement (PPA) with BC Hydro in 2012 and 2013 as approved by Order G-110-12. Negotiation of the agreement began in 2005, and FBC forecast costs of $0.2 million ($0.3 million) before tax). The total costs expected for the negotiation of the new PPA are $0.3 million ($0.4 million before tax). FBC is requesting approval to amortize the balance of the PPA negotiation costs in 2014.

This account will be discontinued effective January 1, 2015.

4.5.6 Right of Way Encroachment Litigation

The Company is expecting to defer approximately $0.09 million ($0.12 million before tax) of legal costs incurred by the end of 2013 associated with an ongoing litigation matter with a land developer in relation to certain encroachments made by the developer on one of the Company's statutory rights of way in Kelowna, British Columbia. Upon resolution of the dispute, any recovered cost will be recorded to the deferral account and the residual is to be amortized into the Company's rates pursuant to Order G-193-08. Although the dispute is not fully resolved, the matter is not being pursued by the land developer and therefore the residual will be amortized in 2014. The Company does not anticipate recovering costs from the developer.

This account will be discontinued effective January 1, 2015.

4.5.7 Trail Office Lease Cost

Legal and other fees associated with the lease of the Trail Office are being amortized over the lease term in accordance with Commission Order G-41-93. This account will be extinguished with the purchase in 2013 of the Trail Office, as approved by Order G-110-12.

This account will be discontinued effective January 1, 2014.

4.5.8 Trail Office Rental to School District 20

Prepaid rental income is being amortized over the lease term in accordance with Generally Accepted Accounting Principles. The account will also be extinguished with the purchase of the Trail Office.

This account will be discontinued effective January 1, 2014.

4.5.9 Deferred Debt Issue Costs

FBC calculates its debt issue costs using the straight-line method. Issuance costs, which include fees for auditors, legal, dealers, filings, rating agencies and trustees, are amortized over the term of the debt issuance. In 2014 FBC will be required to issue debentures, as set out in Section D1.1.1.2. Similar to its previously incurred debt issue costs, FBC intends to amortize the costs over the, term of the debentures, currently forecast to be 30 years.

4.6 ACCOUNTS TO BE DISCONTINUED

In addition to the discontinuations identified in the previous sections, FBC will be discontinuing the use of the following deferral accounts, which 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.

- 2011 Flow-Through and ROE Sharing Mechanism Adjustments
- 2012 Deferred Revenue
- Harmonized Sales Tax Removal/ Provincial Sales Tax Implementation
- Cost of Service Analysis and Rate Design Application
- 2012-2013 Revenue Requirements Application and 2012 Integrated System Plan
- 2011 Revenue Requirements Application
- BC Hydro Waneta Transaction Proceeding
- Residential Inclining Block Rate Application.
- Implementation of New Rate Structures
- Irrigation Rate Payer Group Consultation and Load Research
- Princeton Light and Power Deferred Pension Credit
- Princeton Light and Power Computer Software
- US Generally Accepted Accounting Principles Conversion Cost
- Joint Pole Use Audits, 2008 and 2013
- Demand Side Management Study
- Mandatory Reliability Standards Implementation
- Revenue Protection

4.7 NON RATE BASE DEFERRAL ACCOUNTS

The recommendation for rate base versus non rate base treatment over the other depends on the timing of the deferral account request. If FBC is able to forecast balances for deferral accounts and include them in revenue requirements, then that is the preferred treatment.

In situations where the rates for a particular year have already been set and costs need to be recorded in a deferral account, the Company will, where warranted, request approval for a non-rate base deferral account attracting WACC until such time as rates are re-set under the next revenue requirement or during the annual review process of a PBR, and the account will be transferred to rate base.

In the case of deferral accounts for the preliminary engineering of capital projects that will be the subject of CPCN applications, the account would remain outside of rate base, attracting WACC, until the project commences, whereupon the balance will be transferred to Construction Work in Progress.

Consistent with the Uniform System of Accounts, items that are recoverable from customers but not included in rate base (such as Work in Progress or non-rate base deferral accounts) are afforded WACC treatment so that the utility is afforded the opportunity to earn a fair return on costs prudently incurred to provide service to customers.

The following section identifies FBC's non rate base deferrals.

4.7.1 Kettle Valley Substation Land

Commission Order G-47-13 dated April 3, 2013 directed FBC to hold the amount of $50,000 in a non rate base, non interest bearing deferral account for recovery from ratepayers when and if this portion of the substation site becomes used and useful.

4.7.2 On-Bill Financing (OFB) Pilot Program

In accordance with Commission Order G-163-12, FBC created a non-rate base deferral account attracting AFUDC to capture, on a net-of-tax basis: the OBF Pilot Program and will transfer the balance of this account to rate base effective January 1, 2015.

4.7.3 On-Bill Financing (OFB) Participant Loans

In accordance with Commission Order G-163-12, FBC created a new 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 OBF Pilot Program and the applicable interest charges and recoveries. FBC is seeking approval in Section D4.5.2 to transfer the balance of this account to rate base on January 1, 2015.

4.7.4 CPCN Projects Preliminary Engineering

FBC incurs preliminary and investigative engineering costs in the development of capital projects which are to be approved by way of a CPCN application. As the Company does not intend to include in revenue requirements the impact of forecast CPCN projects until approved and entering plant in service, it is appropriate to retain the preliminary and investigative costs outside of rate base, attracting AFUDC. Following approval of the CPCN application, costs will be transferred to the capital project.

In 2014 FBC will begin work on a new Ruckles substation, and expects to file a CPCN application for the project in 2015. The project is explained in Section C5.7.3.

4.8 *SUMMARY OF APPROVALS SOUGHT REGARDING DEFERRAL ACCOUNTS*

Table D4-4 provides a summary of the request for approvals in this Application related to all rate base deferral accounts. For clarity, FBC is seeking rate base treatment for all of its deferred accounts effective January 1, 2014, with the exception of the accounts identified in Section D4.7 above.

Table D4-4: Summary of Deferral Account Requests

Type of Change	Account Name	Reference
New Account – Rate Base	Rate Stabilization Deferral Mechanism (RSDM)	Section D4.3.1; amortization period of 5 years commencing January 1, 2014.
	Earnings Sharing Mechanism (ESM) Deferral	Section D4.3.2; balance at December 31 of each year to be amortized into rates in the subsequent year
	BC Hydro Application for a Power Purchase Agreement with FBC (RS 3808)	Section D4.3.3; amortization in 2014.
	Generic Cost of Capital Revenue Requirement Impact	Section D4.3.4; amortization in 2014.
	Insurance Expense Variance	Section D4.3.5; amortization in following year.
	Interest Expense Variance	Section D4.3.6, amortization period of 3 years
	Tax Variance	Section D4.3.7; amortization in following year.
	Property Tax Variance	Section D4.3.8; amortization period of 3 years.
	2014 – 2018 Annual Reviews	Section D4.3.9; amortization period of 1 year,
New Account – Non Rate Base	CPCN Projects Preliminary Engineering	Section D4.7.4; transfer to capital project upon approval.
Amortization Period – New or Modified Rate Base	Demand Side Management	Section D4.4.1:change in amortization period from 10 years to 15 years
	On-Bill Financing Pilot Program	Section D4.4.2; change in amortization period from 10 years to 15 years.
	2014 - 2018 PBR Application	Section D4.4.3; amortization over 5 years beginning January 1, 2014.
	Pension and OPEB Expense Variance	Section D4.4.4; change from 3 year amortization period to an 11 year amortization period (EARSL), commencing January 1, 2014

Type of Change	Account Name	Reference
	City of Kelowna Acquisition Customer Benefit	Section D4.4.5; amortization in 2014.
	City of Kelowna Acquisition Legal and Regulatory Costs	Section D4.4.66; amortization in 2014.
	2014 - 2018 Capital Expenditure Plan (Pre Engineering Costs)	Section D4.4.77; amortization period of 2 years beginning in 2014
	BCUC Generic Cost of Capital Proceeding	Section D4.4.88; amortization over 2 years beginning in 2014.
	BCUC Inquiry into the MRS Program	Section D4.4.99; amortization in 2014.
	Kettle Valley Expenditure Review	Section D4.4.1010; amortization in 2014.
	Transmission Customer Rate Design	Section D4.4.1111; amortization in 2014
	2012 Mandatory Reliability Standards Audit	Section D4.4.12: amortization in 2014.
	Mandatory Reliability Standards 2012 -2013 Incremental O&M Expense	Section D4.4.133; amortization in 2014.
Other Rate Base	On-Bill Financing Participant Loans	Section D4.5.2; 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
	Debt Issue Costs	Section D4.5.9; debt issue costs will be incorporated into one account.
Discontinuance	Kelowna Bulk Transformer Capacity Addition Project	Section D4.5.3; discontinuation of this account effective January 1, 2015.
	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	Section D4.5.4; discontinuation of this account effective January 1, 2015.
	Negotiation of new PPA between BC Hydro and FBC	Section D4.5.5; discontinuation of this account effective January 1, 2015.
	Right of Way Encroachment Litigation	Section D4.5.6; discontinuation of this account effective January 1, 2015
	Trail Office Lease Cost	Section D4.5.7; discontinuation of this account effective January 1, 2014.
	Trail Office Rental to School District 20	Section D4.5.8; discontinuation of this account effective January 1, 2014.
	2011 Flow-Through and ROE Sharing Mechanism Adjustments	Section D4.6; discontinuation of this account effective January 1, 2015.
	2012 Deferred Revenue	Section D4.6; discontinuation of this account effective January 1, 2014.

Type of Change	Account Name	Reference
	Harmonized Sales Tax Removal/ Provincial Sales Tax Implementation	Section D4.6; discontinuation of this account effective January 1, 2015.
	Cost of Service and Rate Design Application	Section D4.6; discontinuation of this account effective January 1, 2015.
	2012 - 2013 Revenue Requirements Application and 2012 Integrated System Plan	Section D4.6; discontinuation of this account effective January 1, 2015.
	2011 Revenue Requirement Application Costs	Section D4.6; discontinuation of this account effective January 1, 2014.
	BC Hydro Waneta Transaction Proceeding	Section D4.6; discontinuation of this account effective January 1, 2014
	Residential Inclining Block Rate	Section D4.6; discontinuation of this account effective January 1, 2015.
	Implementation of New Rate Structures	Section D4.6; discontinuation of this account effective January 1, 2015.
	Irrigation Rate Payer Group Consultation and Load Research	Section D4.6; discontinuation of this account effective January 1, 2015.
	Princeton Light and Power Deferred Pension Credit	Section D4.6; discontinuation of this account effective January 1, 2015.
	Princeton Light and Power Computer Software	Section D4.6; discontinuation of this account effective January 1, 2014.
	US GAAP Conversion Costs	Section D4.6; discontinuation of this account effective January 1, 2015.
	Joint Pole Use Audit, 2008	Section D4.6; discontinuation of this account effective January 1, 2014.
	Joint Pole Use Audit, 2013	Section D4.6; discontinuation of this account effective January 1, 2015.
	Mandatory Reliability Standards Implementation	Section D4.6; discontinuation of this account effective January 1, 2015.
	Revenue Protection	Section D4.6; discontinuation of this account effective January 1, 2015.

E: *FINANCIAL SCHEDULES*

REVENUE REQUIREMENTS OVERVIEW

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	Sales Volume (GWh)	3,240	3,258	3,276	3,295	3,318
2	Rate Base	1,226,737	1,257,107	1,282,570	1,298,617	1,307,066
3	Return on Rate Base	7.13%	6.98%	7.01%	7.01%	7.02%
4						
5	**REVENUE DEFICIENCY**			($000s)		
6						
7	**POWER SUPPLY**					
8	Power Purchases	87,814	116,380	134,204	136,716	140,322
9	Water Fees	10,057	10,532	10,479	10,688	10,902
10		97,871	126,913	144,683	147,404	151,224
11	**OPERATING**					
12	O&M Expense	61,386	61,744	60,960	62,378	63,302
13	Capitalized Overhead	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)
14	Wheeling	5,224	4,856	4,952	5,050	5,208
15	Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
16		46,751	46,621	45,939	47,198	48,030
17	**TAXES**					
18	Property Taxes	15,903	16,329	16,612	16,975	17,290
19	Income Taxes	9,241	4,738	3,896	6,818	9,544
20		25,144	21,067	20,508	23,793	26,834
21	**FINANCING**					
22	Cost of Debt	42,607	41,742	42,925	43,545	43,861
23	Cost of Equity	44,899	46,010	46,942	47,529	47,839
24	Depreciation and Amortization	57,773	56,067	58,217	60,557	62,877
25		145,279	143,819	148,085	151,631	154,576
26						
28	Flow Through Adjustments	(14,207)	-	-	-	-
29	Rate Stabilization	22,567	(2,430)	(10,112)	(7,100)	(2,925)
30		8,360	(2,430)	(10,112)	(7,100)	(2,925)
31						
32	**TOTAL REVENUE REQUIREMENT**	323,405	335,990	349,102	362,926	377,740
33						
34	**LESS: REVENUE AT APPROVED RATES**	312,923	325,111	337,798	351,194	365,502
35	**REVENUE DEFICIENCY FOR RATE SETTING**	10,482	10,879	11,304	11,732	12,237
36						
37	**RATE INCREASE**	**3.30%**	**3.30%**	**3.30%**	**3.30%**	**3.30%**

Note: Minor differences due to rounding.

SCHEDULE 1 – UTILITY RATE BASE

		Actual 2012	Forecast 2013	Forecast 2014
			($000s)	
1	Plant in Service, January 1	1,531,831	1,589,905	1,718,111
2	Net Additions	58,074	128,207	86,167
3	Plant in Service, December 31	1,589,905	1,718,111	1,804,278
4				
5	Add:			
6	CWIP not subject to AFUDC	8,136	6,784	7,678
7	Plant Acquisition Adjustment	11,912	11,912	11,912
8	Deferred and Preliminary Charges	19,052	21,732	(2,530)
9				
10		1,629,005	1,758,539	1,821,339
11	Less:			
12	Accumulated Depreciation			
13	and Amortization	395,823	429,731	467,919
14	Contributions in Aid of Construction	97,671	99,416	102,414
15		493,494	529,147	570,333
16				
17	Depreciated Rate Base	1,135,510	1,229,392	1,251,006
18				
19	Prior Year Depreciated Utility Rate Base	1,111,144	1,135,510	1,229,392
20				
21	Mean Depreciated Utility Rate Base	1,123,327	1,182,451	1,240,199
22	Add:			
23	Allowance for Working Capital	(1,264)	1,232	2,184
24	Deferred Opening Balance Adjustment	(1,015)	(6)	(3,801)
25	Kettle Valley Adjustments	(25,756)	(25,756)	-
26	Adjustment for Capital Additions	(6,822)	(11,259)	(11,845)
27				
28	**Mid-Year Utility Rate Base**	**1,088,470**	**1,146,662**	**1,226,737**

Note: Minor differences due to rounding.

TABLE 1-A – UTILITY PLANT IN SERVICE (2013)

	Account		December 31 2012	Additions	Kettle Valley Adjustments	Retirements	December 31 2013
		Hydraulic Production Plants			($000s)		
1	330	Land Rights	962	-		-	962
2	331	Structures and Improvements	13,805	484		(5)	14,284
3	332	Reservoirs, Dams & Waterways	29,357	1,197		(28)	30,527
4	333	Water Wheels, Turbines and Gen.	95,497	688		(88)	96,097
5	334	Accessory Equipment	42,017	716		(473)	42,260
6	335	Other Power Plant Equipment	43,024	694		(129)	43,589
7	336	Roads, Railroads and Bridges	1,287	-		-	1,287
8			**225,949**	**3,779**	**-**	**(723)**	**229,005**
9		**Transmission Plant**					
10	350	Land Rights-R/W	8,708	207		-	8,915
11	350.1	Land Rights-Clearing	7,981	207		-	8,187
12	353	Station Equipment	173,158	19,517		(737)	191,938
13	355	Poles, Towers & Fixtures	93,943	8,668		(1,288)	101,323
14	356	Conductors and Devices	91,751	5,912		(1,283)	96,380
15	359	Roads and Trails	1,121	-		-	1,121
16			**376,663**	**34,511**	**-**	**(3,308)**	**407,865**
17		**Distribution Plant**					
18	360	Land Rights-R/W	3,283	-		-	3,283
19	360.1	Land Rights-Clearing	10,212	-		-	10,212
20	362	Station Equipment	242,630	12,653	(116)	(728)	254,440
21	364	Poles, Towers & Fixtures	152,562	42,562		(347)	194,776
22	365	Conductors and Devices	248,514	10,073		(482)	258,105
23	368	Line Transformers	115,409	5,732		(1,026)	120,115
24	369	Services	7,292	-		-	7,292
25	370	Meters	14,261	1,604		(341)	15,523
26	371	Installation on Customers' Premises	938	-		-	938
27	373	Street Lighting and Signal System	12,174	-		(43)	12,132
28			**807,275**	**72,624**	**(116)**	**(2,967)**	**876,816**
29		**General Plant**					
30	389	Land	9,150	3,200		-	12,350
31	390	Structures-Frame & Iron	337	-		-	337
32	390.1	Structures-Masonry	30,087	11,226		-	41,314
33	391	Office Furniture & Equipment	6,015	125		-	6,140
34	391.1	Computer Equipment	73,783	6,109		(144)	79,748
35	392	Transportation Equipment	22,178	3,054		(591)	24,640
36	394	Tools and Work Equipment	12,229	1,169		(53)	13,346
37	397	Communication Structures and Equipment	26,239	311		-	26,550
38			**180,018**	**25,195**	**-**	**(788)**	**204,425**
39							
40	101	**Plant in Service**	**1,589,904**	**136,108**	**(116)**	**(7,786)**	**1,718,111**
41	107.1	Plant under construction not subject					
42		to AFUDC	8,136				6,784
43	107.2	Plant under construction					
44		subject to AFUDC	5,503				14,524
45	114	Utility Plant Acquisition Adjustment	11,912				11,912
46							
47	105	Utility Plant per Balance Sheet	**1,615,456**				**1,751,331**

Note: Minor differences due to rounding.

TABLE 1-A – UTILITY PLANT IN SERVICE (2014)

	Account		December 31 2013	Additions	Kettle Valley Adjustments	Retirements	December 31 2014
		Hydraulic Production Plants			($000s)		
1	330	Land Rights	962	-	-	-	962
2	331	Structures and Improvements	14,284	184	-	(5)	14,463
3	332	Reservoirs, Dams & Waterways	30,527	1,163	-	(28)	31,662
4	333	Water Wheels, Turbines and Gen.	96,097	-	-	(88)	96,009
5	334	Accessory Equipment	42,260	794	-	(473)	42,581
6	335	Other Power Plant Equipment	43,589	1,115	-	(129)	44,575
7	336	Roads, Railroads and Bridges	1,287	-	-	-	1,287
8			**229,005**	**3,256**	**-**	**(723)**	**231,539**
9		**Transmission Plant**					
10	350	Land Rights-R/W	8,915	237	-	-	9,152
11	350.1	Land Rights-Clearing	8,187	237	-	-	8,425
12	353	Station Equipment	191,938	11,695	12	(737)	202,908
13	355	Poles Towers & Fixtures	101,323	3,118	16	(1,288)	103,169
14	356	Conductors and Devices	96,380	1,235	12	(1,283)	96,344
15	359	Roads and Trails	1,121	-		-	1,121
16			**407,865**	**16,522**	**41**	**(3,308)**	**421,120**
17		**Distribution Plant**					
18	360	Land Rights-R/W	3,283	-	-	-	3,283
19	360.1	Land Rights-Clearing	10,212	-	8	-	10,220
20	362	Station Equipment	254,440	-	1,215	(728)	254,927
21	364	Poles Towers & Fixtures	194,776	22,346	262	(347)	217,037
22	365	Conductors and Devices	258,105	7,549	397	(482)	265,569
23	368	Line Transformers	120,115	2,641	168	(1,026)	121,897
24	369	Services	7,292	-	-	-	7,292
25	370	Meters	15,523	-	-	(7,762)	7,762
26	370	AMI Meters	-	15,826	-	-	15,826
27	371	Installation on Customers' Premises	938	-	-	-	938
28	373	Street Lighting and Signal System	12,132	-	25	(43)	12,113
29			**876,816**	**48,362**	**2,074**	**(10,387)**	**916,864**
30		**General Plant**					
31	389	Land	12,350	-	-	-	12,350
32	390	Structures-Frame & Iron	337	-	-	-	337
33	390.1	Structures-Masonry	41,314	217	-	-	41,531
34	391	Office Furniture & Equipment	6,140	314	-	-	6,454
35	391.1	Computer Equipment	79,748	8,156	-	(144)	87,760
36	392	Transportation Equipment	24,640	2,541	-	(591)	26,590
37	391.2	AMI Software	-	15,091	-	-	15,091
38	394	Tools and Work Equipment	13,346	597	-	(53)	13,890
39	397	Communication Structures and Equipment	26,550	2,901	1,301	-	30,753
40			**204,425**	**29,818**	**1,301**	**(788)**	**234,756**
41							
42	101	**Plant in Service**	**1,718,111**	**97,957**	**3,416**	**(15,206)**	**1,804,278**
43	107.1	Plant under construction not subject					
44		to AFUDC	6,784				7,678
45	107.2	Plant under construction					
46		subject to AFUDC	14,524				9,862
47	114	Utility Plant Acquisition Adjustment	11,912				11,912
48	105	Plant held for future use	-				-
19	105	Utility Plant per Balance Sheet	**1,751,331**				**1,833,730**

Note: Minor differences due to rounding.

Table 1-A-1 – Additions to Plant in Service (2013)

		CWIP Dec. 31, 2012	Expenditures 2013	CWIP Dec 31, 2013	Additions to Plant in Service
			($000s)		
	Hydraulic Production				
1	All Plants Concrete & Structural Rehabilitation	144	384	-	528
2	Upper Bonnington Spillgate Rebuild / Upgrade	-	(10)	-	(10)
3	All Plants Minor Sustaining Projects	33	1,074	-	1,107
4	Upper Bonnington Old Plant Various Unit Upgrades	(51)	514	-	463
5	Upper Bonnington, South Slocan & Corra Linn Power House Windows	-	215	-	215
6	Lower Bonnington, Upper Bonnington & Corra Linn Fire Panels	-	312	-	312
7	All Plants Public Safety & Security	-	214	-	214
8	All Plants Upgrade Station Service Supply	-	42	-	42
9	Corra Linn Unit 2 Life Extension (replace Turbine)	428	450	-	878
10	Queen's Bay Level Gauge Building Ph.1	25	5	-	29
11	**Total Hydraulic Production**	**579**	**3,200**	**-**	**3,779**
12					
13	**Transmission Plant**				
14	Ellison Sexsmith Transmission Tie	763	7,107	-	7,870
15	Okanagan Transmission Reinforcement	-	150	-	150
16	Huth Split Bus	-	18	-	18
17	Capitalized Inventory	6,307	478	6,784	-
18	Backbone Transport Technology Migration	28	(28)	-	-
19	Transmission Line Urgent Repairs	-	498	-	498
20	Transmission Right of Way Acquisition / Easements	-	414	-	414
21	6 Line / 26 Line River Crossing Reconfiguration	498	720	-	1,218
22	Transmission Line Condition Assessment	-	502	-	502
23	PCB Environmental Compliance	1,412	12,781	402	13,791
24	20 Line Rebuild (Warfield Terminal - Salmo)	-	2,072	-	2,072
25	Transmission Line Rehabilitation	-	2,544	-	2,544
26	21-24 Lines Rebuild (Generation Plants)	714	1,625	-	2,339
27	Station Assessment / Minor Planned Projects	23	910	-	933
28	SCADA Systems Sustainment	-	759	-	759
29	Station Unforseen /Urgent Repairs	-	734	-	734
30	Add Arc Flash Detection to Legacy Metal Clad Switchgear	132	497	-	629
31	2013 Transmission Projects-1 (20 Line Rebuild)	9	-	-	9
32	2013 Transmission Projects-2 (Transmission Line Rehab)	32	-	-	32
33	**Total Transmission Plant**	**9,917**	**31,780**	**7,186**	**34,511**
34					
35	**Distribution Plant**				
36	New Connects System Wide	-	16,070	-	16,070
37	Ellison Feeder 2 - Sexsmith Feeder 1 Tie	-	1,141	-	1,141
38	Distribution Small Growth Projects	294	932	-	1,226
39	Distribution Unplanned Growth Projects	-	730	-	730
40	KSA2 - Saucier Feeder Upgrade	-	626	-	626
41	City of Kelowna Utility Assets Acquisition	-	37,766	-	37,766
42	Distribution Condition Assessment	-	1,491	-	1,491
43	Distribution Rehabilitation	-	1,697	-	1,697
44	Fault Indicator Installation	-	153	-	153
45	Distribution Line Rebuilds	-	2,913	-	2,913
46	Small Planned Capital	-	896	-	896
47	Underground Cable Replacement	-	1,404	-	1,404
48	Distribution Forced Upgrades	-	2,231	-	2,231
49	Distribution Urgent Repairs	-	2,852	-	2,852
50	41 Line Salvage & Distribution Underbuild Rehabilitation	69	736	-	805
51	Switcher Replacements	-	1,322	-	1,322
52	**Total Distribution Plant**	**364**	**72,960**	**-**	**73,324**

Note: Minor differences due to rounding.

Table 1-A-1 – Additions to Plant in Service (2013) cont'd

		CWIP Dec. 31, 2012	Expenditures 2013	CWIP Dec 31, 2013	Additions to Plant in Service
			($000s)		
53					
54	**Other Capital**				
55	Communication Upgrades	-	414	-	414
56	Trail Buildings Purchase	-	10,000	-	10,000
57	Buildings	-	907	-	907
58	Kootenay Long Term Facility Strategy	793	(513)	-	280
59	Okanagan Long Term Solution	238	50	288	-
60	Central Warehousing	1,634	906	-	2,540
61	Furniture & Fixtures	-	125	-	125
62	Fleet	-	3,054	-	3,054
63	Telecommunications	-	187	-	187
64	Application Sustainment	-	1,238	-	1,238
65	Infrastructure Sustainment	-	1,143	-	1,143
66	Desktop Infrastructure Sustainment	-	1,147	-	1,147
67	Applications Enhancements	-	1,271	-	1,271
68	PowerSense DSM Reporting Software	115	905	-	1,020
69	Meter	-	703	-	703
70	Advanced Metering Infrastructure	-	13,834	13,834	-
71	Tools	-	467	-	467
72	**Total Other Capital**	**2,780**	**35,837**	**14,122**	**24,495**
73					
74	**TOTAL**	**13,639**	**143,777**	**21,308**	**136,108**
65					
67	**Reconciliation to Capital Plan**				
67	Less City of Kelowna assets acquired				
68	Less Capitalized Overheads		(11,524)		
69	Less Direct Overheads		(4,650)		
70	Less AFUDC		(449)		
71	Add Cost of Removal		6,039		
72	Total Capital in Table C5-1		**133,193**		

Note: Minor differences due to rounding.

Table 1-A-1 – Additions to Plant in Service (2014)

		CWIP Dec. 31, 2013	Expenditures 2014	CWIP Dec 31, 2014	Additions to Plant in Service
			($000s)		
	Hydraulic Production				
1	All Plants Concrete and Structural Rehabilitation	-	528	-	528
2	All Plants Minor Sustaining Capital	-	1,984	-	1,984
3	All Plants Fire Safety	-	560	-	560
4	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	-	184	-	184
5	**Total Hydraulic Production**	**-**	**3,256**	**-**	**3,256**
6					
7	**Transmission Plant**				
8	42 Line Meshed Operation (Huth and Oliver)	-	180	-	180
9	Voltage Support in South Okanagan/Boundary during Contingency	-	671	671	-
10	19 Line/29 Line Reconfiguration	-	352	-	352
11	Transmission Line Condition Assessment	-	908	461	447
12	Transmission Line Rehabilitation	-	4,575	-	4,575
13	Transmission Line Urgent Repairs	-	416	-	416
14	Transmission Line Right of Way Easements	-	474	-	474
15	Station Urgent Repairs	-	648	-	648
16	Station Assessment/Minor Planned Projects	-	1,473	-	1,473
17	Huth Second Distribution Transformer Addition	-	1,757	1,757	-
18	Osoyoos 63 kV Breaker Additions	-	189	189	-
19	Ground Grid Upgrades	-	857	-	857
20	PCB Environmental Compliance	402	7,248	-	7,650
21	Station Smart Device Upgrades	-	323	-	323
22	Spall Breaker House Reconfiguration	-	1,544	-	1,544
23	Capitalized Inventory & Transformers	6,784	-	6,784	-
24	PBR Adjustments	-	(2,419)	-	(2,419)
25	**Total Transmission Plant**	**7,186**	**19,197**	**9,862**	**16,522**
26					
27	**Distribution Plant**				
28	Distribution Line Condition Assessment	-	1,360	-	1,360
29	Distribution Line Rehabilitation	-	3,353	-	3,353
30	Distribution Line Rebuilds	-	2,137	-	2,137
31	Distribution Line Small Planned Capital	-	901	-	901
32	Forced Upgrades and Lines Moves	-	2,307	-	2,307
33	Distribution Urgent Repairs	-	2,235	-	2,235
34	Small Growth Projects	-	1,234	-	1,234
35	Distribution Unplanned Growth	-	963	-	963
36	New Connects System Wide	-	16,482	-	16,482
37	Kaleden Feeder 1 Capacity Upgrades	-	941	-	941
38	Underground Cable Replacement	-	728	-	728
39	Underground Switcher Replacement	-	380	-	380
40	ArcFM Feeder System Audit	-	337	-	337
41	**Total Distribution Plant**	**-**	**33,360**	**-**	**33,360**

Note: Minor differences due to rounding.

Table 1-A-1 – Additions to Plant in Service (2014) cont'd

		CWIP Dec. 31, 2013	Expenditures 2014	CWIP Dec 31, 2014	Additions to Plant in Service
42			**(000s)**		
43	**Other Capital**		($000s)		
44	Communication Upgrades	-	550	-	550
45	Infrastructure Sustainment	-	1,458	-	1,458
46	Desktop Infrastructure Sustainment	-	1,156	-	1,156
47	Application Enhancements	-	880	-	880
48	SCADA Systems Sustainment	-	706	-	706
49	Vehicles	-	2,541	-	2,541
50	Telecommunications	-	176	-	176
51	Buildings	-	633	-	633
52	Furniture and Fixtures	-	314	-	314
53	Tools and Equipment: Transmission-Distribution-Generation	-	597	-	597
54	Application Sustainment	-	1,420	-	1,420
55	Okanagan Long Term Solution (land)	288	145	434	-
56	Advanced Metering Infrastructure	13,834	18,501	-	32,335
57	PowerSense DSM Reporting Software	-	130	-	130
58	Security	-	628	-	628
59	Transform	-	1,351	-	1,351
60	AMI Capital Impacts	-	359	-	359
61	Pension Adjustment	-	(416)	-	(416)
62	**Total Other Capital**	**14,122**	**31,131**	**434**	**44,820**
63					
64	**TOTAL**	**21,308**	**86,944**	**10,295**	**97,957**
65					
67	**Reconciliation to Capital Plan**				
68	Less Capitalized Overheads		(12,277)		
69	Less Direct Overheads		(5,000)		
70	Less AFUDC		(1,375)		
71	Add Cost of Removal		4,465		
72	Total Capital in Table B6-7		72,758		

Note: Minor differences due to rounding.

TABLE 1-B– DEFERRED CHARGES AND CREDITS (2013)

		Rate Base	Balance at Dec. 31, 2012	Opening Bal. Transf./ Adj.	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2013
							($000s)				
1	**Energy Policy**										
2	Demand Side Management	Y	14,866	-	7,334	-	(1,834)	-	-	(2,179)	18,188
3			**14,866**	**-**	**7,334**	**-**	**(1,834)**	**-**	**-**	**(2,179)**	**18,188**
4											
5	**Revenue and Power Supply Variance**										
6	Rate Stabilization Deferral Mechanism (RDSM)	N/A	-	-	-	-	-	-	-	-	-
7	Power Purchase Expense Variance	N	(8,559)	-	(6,120)	(279)	-	-	-	-	(14,958)
8	Revenue Variance	N	3,426	-	4,242	133	-	-	-	-	7,801
9	Generic Cost of Capital (GCOC) Revenue Requirements Impact	N/A	-	-	(3,611)	(43)	-	-	-	-	(3,655)
10			**(5,134)**	**-**	**(5,490)**	**(189)**	**-**	**-**	**-**	**-**	**(10,813)**
11											
12	**Non-Controllable Items**										
13	Pension & Other Post Employment Benefit (OPEB) Variance	N	3,161	-	5,272	164	(1,359)	-		-	7,239
14	Prepaid Pension Costs and OPEB Liability	N	(12,401)	-	(5,091)	(1,227)	1,665	-	403	(207)	(16,858)
15	US GAAP Pension and OPEB Transitional Obligation	N	5,280	-	-	384	(96)	(827)	(33)	207	4,915
16	Interest Expense Variance	N/A	-	-	-	-	-	-	-	-	-
17	Insurance Expense Variance	N/A	-	-	-	-	-	-	-	-	-
18	Tax Variance	N/A	-	-	-	-	-	-	-	-	-
19	Property Tax Variance	N/A	-	-	-	-	-	-	-	-	-
20			**(3,959)**	**-**	**181**	**(679)**	**210**	**(827)**	**370**	**-**	**(4,705)**
21											
22	**Preliminary and Investigative Charges**										
23	Preliminary and Investigative Charges	Y	-	-	150	-	-	-	-	-	150
24	Kelowna Bulk Transformer Capacity Addition (KBTCA) Project	N	322	-	-	20	-	-	-	-	342
25	Corra Linn Spillway Concrete & Spill Gate Rehab CPCN	N	78	-	-	5	-	-	-	-	82
26			**399**	**-**	**150**	**25**	**-**	**-**	**-**	**-**	**575**
27											
28	**Regulatory Compliance**										
29	2014-2018 Performance Based Ratemaking (PBR) Application	N/A	-	-	500	14	(129)	-	-	-	386
30	2014-2018 Annual Reviews	N/A	-	-	-	-	-	-	-	-	-
31	BC Hydro Application for PPA with FBC	N/A	-	-	175	-	(45)	-	-	-	130
32	BCUC Generic Cost of Capital Proceeding	N	13	-	400	14	(103)	-	-	-	323
33	BCUC Inquiry into the Mandatory Reliability Standards (MRS) Program	N	0	-	100	3	(26)	-	-	-	78
34	Kettle Valley Expenditure Review	N	52	-	120	8	(32)	-	-	-	148
35	Transmission Customer Rate Design	N	62	-	110	9	(30)	-	-	-	151
36	City of Kelowna Acquisition Legal and Regulatory Costs	N	109	-	336	18	(89)	-	-	-	374
37			**236**	**-**	**1,741**	**65**	**(453)**	**-**	**-**	**-**	**1,590**

Note: Minor differences due to rounding.

TABLE 1-B– DEFERRED CHARGES AND CREDITS (2013) CONT'D

		Rate Base	Balance at Dec. 31, 2012	Opening Bal. Transf./ Adj.	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2013
38							($000s)				
39	**Other**										
40	Earnings Sharing Mechanism (ESM) Deferral	N/A	-	-	-	-	-	-	-		
41	Right of Way Reclamation (Pine Beetle Kill)	Y	1,038	-	-	-	-	-	-	(173)	865
42	2012 Integrated System Plan - Engineering	N	1,474	-	-	94	(24)	-	(27)	(508)	1,010
43	2014-2018 Capital Expenditure Plan	N	200	-	483	29	(128)	-	-	-	585
44	2012 MRS Audit	N	441	-	-	37	(9)	-	-	-	469
45	MRS 2012-2013 Incremental O&M Expense	N	248	-	900	49	(237)	(8)	-	-	952
46	City of Kelowna Acquisition Customer Benefit	N	-	-	(2,610)	(31)	-	-	-	-	(2,641)
47	Deferred Debt Issue Costs	Y/N	3,305	-	1,587	34	(177)	-	-	(330)	4,419
48			**6,706**	**-**	**360**	**212**	**(575)**	**(8)**	**(27)**	**(1,011)**	**5,658**
49											
50	**Residual**										
51	2011 Flow-Through and ROE Sharing Adjustments	Y	(1,046)	-	-	-		-		-	(1,046)
52	2012 Deferred Revenue	N	(1,969)	-	-	(24)		1,941	63	-	11
53	Harmonized Sales Tax (HST) Removal/Provincial Sales Tax (PST) Implementa	N	2	-	402	5	(102)	-		-	307
54	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	Y	382	-	-	-		-	-	(86)	296
55	Cost of Service and Rate Design Application	Y	798	-	-	-		-	-	(374)	424
56	2012-2013 Revenue Requirements and 2012 Integrated System Plan	N	550	-	-	(6)	2	-	(36)	(1,244)	(735)
57	2011 Revenue Requirements Application Costs	Y	1	-	-	0	(0)	-	-	-	1
58	BC Hydro Waneta Transaction Application	Y	66	-	-	-		-	-	(66)	0
59	Residential Inclining Block Rate & Industrial Stepped Rate Application	Y	121	-	-	-		-	-	-	121
60	Implementation of New Rate Structures	Y	(2)	-	-	-		-	-	-	(2)
61	Irrigation Rate Payer Group Consultation and Load Research	N	45	-	20	0	(5)	-	(1)	(76)	(17)
62	Negotiation of New PPA between BC Hydro and FBC	N	95	-	271	11	(70)	-	(3)	(117)	186
63	Right of Way Encroachment Litigation	N	67	-	30	6	(9)	-	-	-	94
64	Trail Office Lease Cost	Y	131	-	-	-	-	(131)	-	-	-
65	Trail Office Rental to SD20	Y	(851)	-	-	-	-	851	-	-	-
66	Princeton Light and Power Computer Software	Y	7	-	-	-	-	-	-	(6)	0
67	Princeton Light and Power Deferred Pension Credit	Y	(23)	-	-	-	-	-	-	12	(12)
68	US Generally Accepted Accounting Principles Conversion Cost	Y	178	-	-	-	-	-	-	(297)	(119)
69	Joint Pole Use Audit, 2008	Y	22	-	-	-	-	-	-	(22)	(0)
70	Joint Pole Use Audit, 2013	N	-	-	100	-	(25)	-	(1)	(94)	(20)
71	Demand Side Management Study	Y	61	-	-	-	-	-	-	(61)	(0)
72	MRS Implementation	N	542	-	-	34	(9)	-	(11)	(251)	304
73	Revenue Protection	Y	(12)	-	-	-		-	-	-	(12)
74			**(835)**	**-**	**823**	**26**	**(219)**	**2,661**	**9**	**(2,683)**	**(218)**
75											
76	**Total**		**12,278**	**-**	**5,100**	**(540)**	**(2,871)**	**1,826**	**352**	**(5,872)**	**10,275**

Note: Certain deferral accounts were excluded from rate base in 2012 and 2013 pursuant to Order G-110-12. FBC is requesting rate base treatment for these accounts effective January 1, 2014.

Note: Minor differences due to rounding.

TABLE 1-B– DEFERRED CHARGES AND CREDITS (2014)

		Balance at Dec. 31, 2013	Opening Bal. Transf./ Adj.	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2014
						($000s)				
1	**Energy Policy**									
2	Demand Side Management	18,188	-	3,001	-	(750)	-	-	(1,395)	19,043
3		**18,188**	**-**	**3,001**	**-**	**(750)**	**-**	**-**	**(1,395)**	**19,043**
4	**Revenue and Power Supply Variance**									
5	Rate Stabilization Deferral Mechanism (RSDM)	-	-	(30,089)	-	7,522	-	-	-	(22,567)
6	Power Purchase Expense Variance Deferral	(14,958)	-	-	-	-	14,558	401	-	-
7	Revenue Variance	7,801	-	-	-	-	(7,619)	(182)	-	-
8	Generic Cost of Capital Revenue Requirements Impact	(3,655)	-	-	-	-	3,611	43	-	-
9		**(10,813)**	**-**	**(30,089)**	**-**	**7,522**	**10,550**	**262**	**-**	**(22,567)**
10	**Non-Controllable Items**									
11	Pension & Other Post Employment Benefits (OPEB) Expense Variance	7,239	-	-	-	-	-	(168)	(643)	6,428
12	Prepaid Pension Costs and OPEB Liability	(16,858)	-	(166)	-	-	-	-	-	(17,024)
13	US GAAP Pension and OPEB Transitional Obligation	4,915	-	-	-	-	(827)	-	-	4,088
14	Insurance Expense Variance	-	-	-	-	-	-	-	-	-
15	Interest Expense Variance	-	-	-	-	-	-	-	-	-
16	Tax Variance	-	-	-	-	-	-	-	-	-
17	Property Tax Variance	-	-	-	-	-	-	-	-	-
18		**(4,705)**	**-**	**(166)**	**-**	**-**	**(827)**	**(168)**	**(643)**	**(6,509)**
19	**Preliminary and Investigative Charges**									
20	Preliminary and Investigative Charges	150	-	150	-	-	(150)	-	-	150
21	Corra Linn Spillway Concrete & Spill Gate Rehab CPCN	82	-	-	3	-	(85)		-	-
2	Kelowna Bulk Transformer Capacity Addition (KBTCA)	342	-	-	10	-			(353)	-
23		**575**	**-**	**150**	**13**	**-**	**(235)**	**-**	**(353)**	**150**
24	**Regulatory Compliance**									
25	2014-2018 Performance Based Ratemaking (PBR) Application	386	-	-	-	-	-	(11)	(75)	300
26	2014-2018 Annual Reviews	-	-	100	-	(25)	-	-	-	75
27	BC Hydro Application for Power Purchase Agreement with FBC	130	-	-	-	-	-	-	(130)	-
28	BCUC Generic Cost of Capital Proceeding	323	-	-	-	-	-	-	(161)	161
29	BCUC Inquiry into the Mandatory Reliability Standards (MRS) Program	78	-	-	-	-	-	-	(78)	-
30	Kettle Valley Expenditure Review	148	-	-	-	-	-	-	(148)	-
31	Transmission Customer Rate Design	151	-	-	-	-	-	-	(151)	-
32	City of Kelowna Acquisition Legal and Regulatory Costs	374	-	-	-	-	-	-	(374)	-
33		**1,590**	**-**	**100**	**-**	**(25)**	**-**	**(11)**	**(1,118)**	**536**

Note: Minor differences due to rounding.

TABLE 1-B– DEFERRED CHARGES AND CREDITS (2014) CONT'D

		Balance at Dec. 31, 2013	Opening Bal. Transf./ Adj.	Additions and Transfers	Add Deferred Financing Cost	Less Taxes ($000s)	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2014
34	**Other**									
35	Earnings Sharing Mechanism (ESM) Deferral	-	-	-	-	-	-	-	-	-
36	Right of Way Reclamation (Pine Beetle Kill)	865	-	-	-	-	-	-	(173)	692
37	2012 Integrated System Plan - Engineering	1,010	-	-	-	-	-	-	(337)	673
38	2014-2018 Capital Expenditure Plan	585	-	-	-	-	-	-	(292)	292
39	2012 MRS Audit	469	-	-	-	-	-	-	(469)	-
40	MRS 2012-2013 Incremental O&M Expense	952	-	-	-	-		-	(952)	-
41	City of Kelowna Acquisition Customer Benefit	(2,641)	-	-	-	-	2,610	31	-	-
42	Deferred Debt Issue Costs	4,419	-	1,279	-	(180)	-	-	(359)	5,159
43		**5,658**	**-**	**1,279**	**-**	**(180)**	**2,610**	**31**	**(2,582)**	**6,816**
44	**Residual**									
45	2011 Flow-Through and ROE Sharing Mechanism Adjustments	(1,046)	-	-	-	-	1,046		-	-
46	2012 Deferred Revenue	11	-	-	-	-	-	(11)	-	-
47	Harmonized Sales Tax (HST) Removal/Provincial Sales Tax (PST) Implementation P	307	-	-	-	-	-	(4)	(304)	-
48	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	296	-	-	-	-	-	-	(296)	-
49	Cost of Service and Rate Design Application	424	-	-	-	-	-	-	(424)	-
50	2012-2013 Revenue Requirements and 2012 Integrated System Plan	(735)	-	-	-	-	-	-	735	-
51	2011 Revenue Requirement Application costs	1	-	-	-	-	-	-	(1)	-
52	Residential Inclining Block Rate	121	-	-	-	-	-		(121)	-
53	Implementation of New Rate Structures	(2)	-	-	-	-	-		2	-
54	Irrigation Rate Payer Group Consultation and Load Research	(17)	-	-	-	-	-	-	17	-
55	Negotiation of new PPA between BC Hydro and FBC	186	-	-	-	-	-	-	(186)	-
56	Right of Way Encroachment Litigation	94	-	-	-	-	-	-	(94)	-
57	Princeton Light and Power Deferred Pension Credit	(12)	-	-	-	-	-	-	12	-
58	US Generally Accepted Accounting Principles Conversion Costs	(119)	-		-	-	-		119	-
59	Joint Pole Use Audit, 2013	(20)	-	100	-	(25)	-	-	(55)	-
60	MRS Implementation	304	-	-	-	-	-	-	(304)	-
61	Revenue Protection	(12)	-	-	-	-	-		12	-
62		**(218)**		**100**	**-**	**(25)**	**1,046**	**(14)**	**(889)**	**-**
63										
64	**Total**	**10,274**	**-**	**(25,625)**	**13**	**6,542**	**13,145**	**100**	**(6,979)**	**(2,530)**

Note: Minor differences due to rounding.

TABLE 1-C– ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (2013)

	Account		Acc. Prov. For Depreciation Dec. 31, 2012	Deprec. Rate	Asset Balance Dec. 31, 2012	Depreciation Expense Dec. 31, 2013	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2013
			($000s)			($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(509)	3.8%	962	37	-	(472)
2	331	Structures and Improvements	5,533	1.3%	13,805	178	(47)	5,664
3	332	Reservoirs, Dams and Waterways	6,331	2.0%	29,357	590	(132)	6,789
4	333	Water Wheels, Turbines & Generators	4,550	2.0%	95,497	1,862	(148)	6,264
5	334	Accessory Electrical Equipment	7,872	2.4%	42,017	992	(535)	8,329
6	335	Other Power Plant Equipment	10,706	2.3%	43,024	998	(190)	11,515
7	336	Roads, Railroads and Bridges	523	1.5%	1,287	19	-	542
8			35,007	2.1%	225,949	4,676	(1,052)	38,631
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	8,708	-	-	(62)
11	350.1	Land Rights - Clearing	2,258	1.5%	7,981	117	-	2,375
12	353	Station Equipment	7,800	3.4%	173,158	5,954	(2,351)	11,404
13	355	Poles, Towers & Fixtures	12,018	2.6%	93,943	2,476	(2,004)	12,490
14	356	Conductors and Devices	6,731	2.1%	91,751	1,878	(1,772)	6,838
15	359	Roads and Trails	152	2.7%	1,121	30	-	182
16			28,897	2.8%	376,663	10,456	(6,127)	33,227
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	3,283	-	-	(868)
19	360.1	Land Rights - Clearing	446	2.7%	10,212	270	-	716
20	362	Station Equipment	79,936	2.2%	242,630	5,065	(1,225)	83,777
21	364	Poles, Towers & Fixtures	46,249	2.1%	152,562	3,186	(2,020)	47,416
22	365	Conductors and Devices	73,018	2.6%	248,514	6,290	(878)	78,431
23	368	Line Transformers	24,152	3.4%	115,409	3,894	(1,251)	26,795
24	369	Services	6,559	0.2%	7,292	12	-	6,571
25	370	Meters	6,144	6.7%	14,261	953	(341)	6,756
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	3,865	2.4%	12,174	284	(43)	4,106
28			236,088	2.5%	807,275	19,955	(5,758)	250,286
29		General Plant						
30	389	Land	897	0.0%	9,150	-	-	897
31	390	Structures - Frame & Iron	541	0.7%	337	2	-	543
32	390.1	Structures - Masonry	6,276	6.1%	24,719	1,510	(51)	7,735
33	391	Office Furniture & Equipment	4,886	3.6%	6,015	219	(1)	5,104
34	391.1	Computer Equipment	53,134	7.6%	73,783	5,615	(172)	58,578
35	392	Transportation Equipment	2,843	10.7%	22,178	2,375	(605)	4,613
36	394	Tools and Work Equipment	8,669	4.0%	12,229	493	(58)	9,105
37	397	Communication Structures and Equipment	10,275	8.1%	26,239	1,794	(1)	12,068
38			87,523	6.9%	174,650	12,009	(888)	98,643
39								
40	108	Total Accumulated Depreciation	387,515	3.0%	1,584,536	47,096	(13,825)	420,787
41								
42		Deduct - Portion of CIAC Depreciated				(3,472)		
43								
44	403	Depreciation Expense				43,624		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,396		11,912	186		5,582
48	390	Leasehold Improvements	3,843		5,368	140		3,983
49		Rate Stabilization Adjustment	(932)			311		(621)
50		Total Accumulated Amortization	8,307			637		8,944
51		Accumulated Amortization per						
52		Balance Sheet	395,823			44,261		429,731

Note: Minor differences due to rounding.

TABLE 1-C– ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (2014)

	Account		Acc. Prov. For Depreciation Dec. 31, 2013	Deprec. Rate	Asset Balance Dec. 31, 2013	Depreciation Expense Dec. 31, 2014	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2014
			($000s)			($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(472)	3.8%	962	37	-	(435)
2	331	Structures and Improvements	5,664	1.3%	14,284	184	(29)	5,819
3	332	Reservoirs, Dams and Waterways	6,789	2.0%	30,527	614	(178)	7,225
4	333	Water Wheels, Turbines & Generators	6,264	2.0%	96,097	1,874	(88)	8,050
5	334	Accessory Electrical Equipment	8,329	2.4%	42,260	997	(576)	8,750
6	335	Other Power Plant Equipment	11,515	2.3%	43,589	1,011	(274)	12,252
7	336	Roads, Railroads and Bridges	542	1.5%	1,287	19	-	561
8			38,631	2.1%	229,005	4,736	(1,144)	42,223
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	8,915	-	-	(62)
11	350.1	Land Rights - Clearing	2,375	1.5%	8,187	120	-	2,495
12	353	Station Equipment	11,404	3.4%	191,938	6,609	(2,426)	15,587
13	355	Poles, Towers & Fixtures	12,490	2.6%	101,323	2,683	(1,738)	13,435
14	356	Conductors and Devices	6,838	2.1%	96,380	1,982	(1,461)	7,358
15	359	Roads and Trails	182	2.7%	1,121	30	-	212
16			33,227	2.8%	407,865	11,424	(5,625)	39,025
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	3,283	-	-	(868)
19	360.1	Land Rights - Clearing	716	2.7%	10,212	276	-	992
20	362	Station Equipment	83,777	2.2%	254,440	6,217	(728)	89,266
21	364	Poles, Towers & Fixtures	47,416	2.1%	194,776	4,277	(1,612)	50,080
22	365	Conductors and Devices	78,431	2.6%	258,105	6,827	(909)	84,348
23	368	Line Transformers	26,795	3.4%	120,115	4,178	(1,175)	29,797
24	369	Services	6,571	0.2%	7,292	12	-	6,583
25	370	Meters	6,756	6.7%	15,523	1,037	(4,384)	3,409
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	4,106	2.4%	12,132	289	(43)	4,352
28			250,286	2.6%	876,816	23,113	(8,851)	264,548
29		General Plant						
30	389	Land	897	0.0%	12,350	-	-	897
31	390	Structures - Frame & Iron	543	0.7%	337	2	-	545
32	390.1	Structures - Masonry	8,968	6.1%	38,658	2,362	-	11,330
33	391	Office Furniture & Equipment	5,104	3.6%	6,140	223	-	5,327
34	391.1	Computer Equipment	58,578	7.6%	79,748	6,069	(144)	64,503
35	392	Transportation Equipment	4,613	10.7%	24,640	2,639	(477)	6,775
36	394	Tools and Work Equipment	9,105	4.0%	13,346	538	(53)	9,590
37	397	Communication Structures and Equipment	12,068	8.1%	26,550	2,773	-	14,841
38			99,876	7.2%	201,769	14,606	(673)	113,809
39								
40	108	Total Accumulated Depreciation	422,020	3.1%	1,715,455	53,879	(16,293)	459,606
41								
42		Deduct - Portion of CIAC Depreciated				(3,595)		
43								
44	403	Depreciation Expense				50,284		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,582		11,912	186		5,768
48	390	Leasehold Improvements	2,750		2,656	105		2,855
49		Rate Stabilization Adjustment	(621)			311		(310)
50		Total Accumulated Amortization	7,711			602		8,313
51		Accumulated Amortization per						
52		Balance Sheet	429,731			50,886		467,919

Note: Minor differences due to rounding.

TABLE 1-D– CONTRIBUTIONS IN AID OF CONSTRUCTION

	Actual	Projected		Forecast	
	Dec. 31 2012	2013 Additions	Dec. 31 2013	2014 Additions	Dec. 31 2014
			($000s)		
Gross Book Value	147,743	5,217	152,960	6,593	159,553
Accumulated Depreciation	(50,072)	(3,472)	(53,544)	(3,595)	(57,139)
Net Book Value	**97,671**		**99,416**		**102,414**

Note: Minor differences due to rounding.

TABLE 1-E– ALLOWANCE FOR WORKING CAPITAL (2013)

	Lag Days Calculation	Lag (Lead) Days	2013 Forecast ($000s)	2013 Extended ($000s)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	45.1	304,875	13,750	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	27.6	4,184	115	
5	Contract Revenue	41.4	1,709	71	
6	Miscellaneous Revenue	43.5	1,964	85	
7	Investment Income	15.2	90	1	
8			**$ 312,822**	**$ 14,023**	**44.8**
9					
10	**Expenses**				
11	Power Purchases	42.0	84,266	3,539	
12	Wheeling	40.2	5,210	209	
13	Water Fees	(1.0)	9,387	(9)	
14	*Operating Labour:*				
15	Salaries & Wages	6.8	13,382	91	
16	Employee Benefits	36.1	12,326	445	
17	Contracted Manpower	50.6	10,086	510	
18	Property Tax	1.4	14,867	21	
19	Rental of T&D Facilities	48.6	3,255	158	
20	Office Lease - Kelowna	(15.2)	895	(14)	
21	Office Lease - Trail	91.5	909	83	
22	Materials	39.4	3,647	144	
23	Insurance	(182.5)	1,596	(291)	
24	Income Tax	15.2	10,363	158	
25	Interest	88.3	39,848	3,519	
26			**$ 210,039**	**$ 8,563**	**40.8**
27					
28	**Net Lag/(Lead) Days**				**4.1**
29					
30					
31	**Forecast Working Capital Allowance**				($000s)
32					
33	**Lead-Lag Study Allowance**				
34	Net Lag Days/365 times Expenses				$ 2,336
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			$ 1,598	
38	Employee Loans			$ 349	
39	Uncollectable Accounts			$ 1,024	
40	Inventory (forecast monthly average investment)			$ 481	
41					$ 3,452
42	**Less Funds Available:**				
43	Average Customer Deposits			$ 4,003	
44	Average Provincial Services Tax			$ 310	
45	Average Goods and Services Tax			$ 243	
46					$ 4,557
47					
48	**2013 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**$ 1,232**

Note: Minor differences due to rounding.

TABLE 1-E– ALLOWANCE FOR WORKING CAPITAL (2014)

	Lag Days Calculation	**Lag (Lead) Days**	**2014 Forecast ($000s)**	**2014 Extended ($000s)**	**Weighted Average Lag Days**
1	**Revenue**				
2	Tariff Revenue	45.3	323,405	14,650	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	27.6	4,156	115	
5	Contract Revenue	41.4	1,385	57	
6	Miscellaneous Revenue	43.5	1,962	85	
7	Investment Income	15.2	78	1	
8			**$ 330,987**	**$ 14,909**	**45.0**
9					
10	**Expenses**				
11	Power Purchases	41.7	87,814	3,662	
12	Wheeling	40.2	5,224	210	
13	Water Fees	(1.0)	10,057	(10)	
14	*Operating Labour:*				
15	Salaries & Wages	5.3	13,968	74	
16	Employee Benefits	13.2	12,880	170	
17	Contracted Manpower	50.6	10,288	521	
18	Property Tax	1.4	15,903	22	
19	Rental of T&D Facilities	48.6	3,411	166	
20	Office Lease - Kelowna	(15.2)	1,016	(15)	
22	Materials	45.6	**5,812**	265	
23	Insurance	(182.5)	1,734	(316)	
24	Income Tax	15.2	9,241	140	
25	Interest	85.2	42,607	3,630	
26			**$ 219,955**	**$ 8,518**	**38.7**
27					
28	**Net Lag/(Lead) Days**				**6.3**
29					
30					
31	**Forecast Working Capital Allowance**			($000s)	
32					
33	**Lead-Lag Study Allowance**				
34	Net Lag Days/365 times Expenses				$ 3,807
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			$ 1,279	
38	Employee Loans			$ 349	
39	Uncollectable Accounts			$ 1,024	
40	Inventory (forecast monthly average investment)			$ 481	
41					$ 3,133
42	**Less Funds Available:**				
43	Average Customer Deposits			$ 4,003	
44	Average Provincial Services Tax			$ 422	
45	Average Goods and Services Tax			$ 331	
46					$ 4,756
47					
48	**2014 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**$ 2,184**

Note: Minor differences due to rounding.

TABLE 1-F– ADJUSTMENT FOR CAPITAL EXPENDITURES (2013)

		Plant in Service ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	2,450	11.5	2,348
2	February	2,707	10.5	2,368
3	March	40,586	9.5	32,130
4	April	3,932	8.5	4,359
5	May	2,756	7.5	1,722
6	June	3,390	6.5	1,836
7	July	2,861	5.5	1,311
8	August	4,612	4.5	1,730
9	September	5,012	3.5	1,462
10	October	6,337	2.5	1,320
11	November	15,072	1.5	1,884
12	December	41,177	0.5	1,716
13	**Total**	**130,891**		**54,187**
14	**Less Simple Average**			65,446
15	**Adjustment to Rate Base**			**(11,259)**
16	* Plant in Service is reduced by Contributions in Aid of Construction			

Note: Minor differences due to rounding.

TABLE 1-F – ADJUSTMENT FOR CAPITAL EXPENDITURES (2014)

		Plant in Service ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	1,353	11.5	1,296
2	February	6,622	10.5	5,795
3	March	13,567	9.5	10,740
4	April	5,521	8.5	3,911
5	May	2,704	7.5	1,690
6	June	3,326	6.5	1,801
7	July	2,807	5.5	1,287
8	August	4,525	4.5	1,697
9	September	4,917	3.5	1,434
10	October	6,217	2.5	1,295
11	November	14,787	1.5	1,848
12	December	25,019	0.5	1,042
13	**Total**	**91,364**		**33,837**
14	**Less Simple Average**			45,682
15	**Adjustment to Rate Base**			**(11,845)**
16	* Plant in Service is reduced by Contributions in Aid of Construction			

Note: Minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Actual 2012	Projected 2013	Forecast 2014
1	SALES VOLUME (GWh)	3,144	3,189	3,240
2				
3			($000s)	
4				
5	ELECTRICITY SALES REVENUE	282,943	304,875	323,405
6				
7	EXPENSES			
8	Power Purchases	75,999	84,266	87,814
9	Water Fees	9,253	9,387	10,057
10	Wheeling	4,813	5,210	5,224
11	Net O&M Expense	42,574	45,645	49,109
12	Property Tax	13,912	14,867	15,903
13	Depreciation and Amortization	48,587	49,781	57,773
14	Other Income	(9,270)	(7,947)	(7,582)
15	Flow-Through Adjustments	781	6,159	(14,207)
16	Rate Stabilization	-	-	22,567
17	UTILITY INCOME BEFORE TAX	96,293	97,507	96,747
18	Less:			
19	INCOME TAXES	9,097	10,363	9,241
20				
21	EARNED RETURN	87,197	87,144	87,506
22	RETURN ON RATE BASE			
23	Utility Rate Base	1,088,470	1,146,662	1,226,737
24	Return on Rate Base	8.01%	7.60%	7.13%

Note: Minor differences due to rounding.

TABLE 2-A NET OPERATING AND MAINTENANCE EXPENSE

		Actual 2012	Projected 2013	Forecast 2014
			($000s)	
1	**Gross O&M Expense**	53,542	57,169	61,386
2				
3	Less Capitalized Overhead	(10,969)	(11,524)	(12,277)
4				
5	Net O&M Expense	42,574	45,645	49,109

Note: Minor differences due to rounding.

TABLE 2-B PROPERTY TAXES

		Actual 2012	Forecast 2013	Forecast 2014
			($000s)	
1	Generating Plant	2,834	2,836	3,001
2	Transmission and Distribution	6,453	7,268	7,932
3	Substation Equipment	4,045	4,196	4,376
4	Land and Buildings	580	567	593
5	**Total Property Tax**	**13,912**	**14,867**	**15,903**

Note: Minor differences due to rounding.

TABLE 2-C FLOW-THROUGH ADJUSTMENTS

	Account	Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Adjustment in: 2012	2013	2014
				($000s)				($000s)	
1	2011 Flow-Through and Sharing Mechanism Adjustments					**1,046**	-	-	(1,046)
2	Prior Year Flow-Through and Sharing Mechanism Adjustments						(6,221)	-	-
3	2012 Deferred Revenue					**1,941**	1,941	(1,941)	-
4	Revenue Variance 2012	287,445	282,943	(4,503)	1,126	**(3,377)**	(3,377)		3,377
5	Revenue Variance 2013	310,531	304,875	(5,655)	1,414	**(4,242)**	-	(4,242)	4,242
6	Power Purchase Expense Variance 2012	96,502	85,253	11,160	(2,813)	**8,438**	8,438		(8,438)
7	Power Purchase Expense Variance 2013	101,813	93,653	8,160	(2,040)	6,120	-	6,120	(6,120)
							-	-	
8	Generic Cost of Capital RR Impact			4,815	(1,204)	**3,611**	-	3,611	(3,611)
9	City of Kelowna Acquisition Customer Benefit			3,480	(870)	**2,610**	-	2,610	(2,610)
10	Flow Through Adjustment						**781**	**6,159**	**(14,207)**

Note: Minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

		Actual 2012	Forecast 2013	Forecast 2014
			($000s)	
1	UTILITY INCOME BEFORE TAX	96,293	97,507	96,747
2	Deduct:			
3	Interest Expense	38,686	39,848	42,607
4				
5	ACCOUNTING INCOME	57,607	57,659	54,139
6				
7	Deductions			
8	Capital Cost Allowance	58,308	60,302	67,932
9	Capitalized Overhead	10,969	11,524	12,277
10				
11	Incentive & Revenue Deferrals	(781)	(6,159)	(8,360)
12	Financing Fees	338	655	707
13	Pension Contribution	-	6,388	10,586
14	Other Post Employment Benefit (OPEB) Contribution	-	657	721
15	All Other (net effect)	463	1,192	885
16		69,297	74,559	84,749
17				
18	Additions			
19	Amortization of Deferred Charges	5,439	5,520	6,888
20	Pension Expenses	-	4,222	8,342
21	Other Post Employment Benefit (OPEB) Expenses	-	3,469	3,958
22	Depreciation	43,149	44,261	50,886
23		48,587	57,472	70,073
24				
25	TAXABLE INCOME	36,898	40,572	39,464
26				
27	Tax Rate	25.0%	25.0%	25.0%
28				
29	Taxes Payable	9,224	10,143	9,866
30	Prior Years' Overprovisions/(Underprovisions)	(167)	-	(805)
31	Investment Tax Credit	(18)	-	-
32	Pension Tax Effect	-	45	-
33	Deferred Charges Tax Effect	57	175	180
34				
35	**REGULATORY TAX PROVISION**	9,097	10,363	9,241

Note: Minor differences due to rounding.

TABLE 3-A CAPITAL COST ALLOWANCE (2013)

	Class		2012 Closing UCC	2013 Additions	Half-Year Rule	CCA Rate	2013 CCA	Closing UCC
					($000s)			
1	1A	Buildings	227,724	-	-	4%	9,109	218,615
2	1B	Buildings	4,365	13,726	6,863	6%	674	17,417
3	17	Non Electronic Eq. (All Gen)	118,362	3,779	1,889	8%	9,620	112,521
4	2		21,172	-	-	6%	1,270	19,902
5	3		1,264	-	-	5%	63	1,201
6	6		8	-	-	10%	1	7
7	8	Furniture & Tools / Small Equipment	4,259	2,094	1,047	20%	1,061	5,292
8	1C	COK CCA 4% Rate Class (Prior to 2004)	-	4,100	2,050	4%	82	4,018
9	10	Vehicles	5,707	3,054	1,527	30%	2,170	6,591
10	12	Tools & Equipment	1,231	1,271	635	100%	1,866	636
11	13		1,724	-	-	est	150	1,574
12	42	Fibre & Communication	2,210	601	300	12%	301	2,510
13	46	Network Hardware & Software	3,410	1,143	572	30%	1,195	3,358
14	45	IT Equipment	184	-	-	45%	83	101
15	47	T&D+Environmental (less land)	344,857	85,455	42,727	8%	31,007	399,305
16	50	Electronic Processing Equipment	1,298	3,405	1,703	55%	1,650	3,053
17			**737,775**	**118,628**	**59,314**		**60,302**	**796,101**
18								
19								
20	Land			3,614				
21	Net Salvage			(5,275)				
22	AFUDC			2,400				
23	Capitalized overhead			11,524				
24	CIAC			5,217				
25	Plant in service			**136,108**				

Note: Minor differences due to rounding.

TABLE 3-A CAPITAL COST ALLOWANCE (2014)

Line	Class		2013 Closing UCC	2014 Additions	Half-Year Rule	CCA Rate	2014 CCA	Closing UCC
					($000s)			
1	1A	Buildings	218,615	-	-	4%	8,745	209,870
2	1B	Buildings	17,417	217	108	6%	1,052	16,582
3	17	Non Electronic Eq. (All Gen)	112,521	3,256	1,628	8%	9,132	106,645
4	2		19,902	-	-	6%	1,194	18,708
5	3		1,201	-	-	5%	60	1,141
6	6		7	-	-	10%	1	6
7	8	Furniture & Tools / Small Equipment	5,292	911	456	20%	1,150	5,053
8	1C	COK CCA 4% Rate Class (Prior to 2004)	4,018	-	-	4%	161	3,857
9	10	Vehicles	6,591	2,541	1,271	30%	2,358	6,774
10	12	Tools & Equipment	636	3,009	1,505	100%	2,140	1,505
11	13		1,574	-	-	est	150	1,424
12	42	Fibre & Communication	4,244	726	363	12%	553	4,417
13	45	IT Equipment	101	-	-	45%	45	56
14	46	Network Hardware & Software	3,358	10,512	5,256	30%	2,584	11,286
15	47	T&D+Environmental (less land)	414,270	54,189	27,094	8%	35,309	433,150
16	50	Electronic Processing Equipment	3,053	5,885	2,943	55%	3,298	5,640
17			**812,801**	**81,246**	**40,623**		**67,932**	**826,115**
18								
19								
20	Land			474				
21	Net Salvage			(4,008)				
22	AFUDC			1,375				
23	Capitalized overhead			12,277				
24	CIAC			6,593				
25	Plant in service			**97,957**				

Note: Minor differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

			Actual 2012	Forecast 2013	Forecast 2014
				($000s)	
1	Share Capital		180,122	180,122	180,122
2	Retained Earnings		268,691	293,201	294,496
3					
4	COMMON EQUITY - OPENING BALANCE		448,813	473,323	474,618
5					
6	Less:	Common Dividends	(24,000)	(46,000)	(28,000)
7					
8	Add:	Net Income	48,510	47,295	44,899
9		Shares Issued	-	-	15,000
10					
11	COMMON EQUITY - CLOSING BALANCE		473,323	474,618	506,517
12					
13	SIMPLE AVERAGE		461,068	473,971	490,568
14					
15	Adjustment for Shares Issued		-	-	3,842
16	Deemed Equity Adjustment		-	(15,306)	(3,715)
17					
18	COMMON EQUITY - AVERAGE		461,068	458,665	490,695

Note: Minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

		Actual 2012	Forecast 2013	Forecast 2014
			($000s)	
1	Secured and Senior Unsecured Debt	637,483	655,781	736,658
2	Proportion	57.22%	57.19%	60.05%
3	Embedded Cost	6.03%	5.87%	5.69%
4	Cost Component	3.45%	3.36%	3.42%
5	Return	38,422	38,525	41,952
6				
7	Short Term Debt	15,599	32,216	(616)
8	Proportion	1.40%	2.81%	-0.05%
9	Embedded Cost	1.69%	4.11%	-106.41%
10	Cost Component	0.02%	0.12%	0.05%
11	Return (including fees)	264	1,323	655
12				
13	Common Equity	461,068	458,665	490,695
14	Proportion	41.38%	40.00%	40.00%
15	Embedded Cost	10.52%	9.15%	9.15%
16	Cost Component	4.35%	3.66%	3.66%
17	Return	48,510	47,295	44,899
18				
19	TOTAL CAPITALIZATION	1,114,150	1,146,662	1,226,737
20	RATE BASE	1,088,470	1,146,662	1,226,737
21				
22	Earned Return	87,195	87,143	87,506
23				
24	RETURN ON CAPITAL	7.83%	7.60%	7.13%
25	RETURN ON RATE BASE	8.01%	7.60%	7.13%

Note: Minor differences due to rounding.