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September 28, 2011

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: FortisBC Energy Utilities[1] ("FEU" or the "Companies") 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application" or "RRA")

Update of Tables in the Application (Exhibit B-1) based on the Evidentiary Update dated September 12, 2011 (Exhibit B-21)

On May 4, 2011, the FEU filed the Application referenced above. However, there have been evidentiary updates since that time, such that the Application details are now found in the following exhibits in the proceeding record:

1. Exhibit B-1 (Application filed May 4, 2011 – redacted public version)
2. Exhibit B-1-1 (Confidential portion of the Application filed May 4, 2011)
3. Exhibit B-1-2 (Amendment to the Application dated May 16, 2011)
4. Exhibit B-11 (Evidentiary Update dated July 19, 2011)
5. Exhibit B-21 (Evidentiary Update dated September 12, 2011)

In order to assist all parties during the Oral Public Hearing, the FEU enclose replacement pages for the Application (Exhibit B-1) with tables and quoted figures[2] in the narrative updated to reflect the latest forecasts as included in the financial schedules and rate requests provided in the Evidentiary Update dated September 12, 2011. **We confirm that these replacement pages are for ease of reference only and reflect information already on the record.**

We recommend that the parties insert these pages into the Application binder volume 1, and put a stroke through the original page indicating that it has been replaced and updated.

[1] FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), FortisBC Energy (Whistler) Inc. ("FEW"), and FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson")

[2] Only figures have been updated; where narrative in Exhibit B-1 has been superseded by Commission orders or changes to the Companies' requests since May 4, 2011, the narrative has not been amended.

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

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

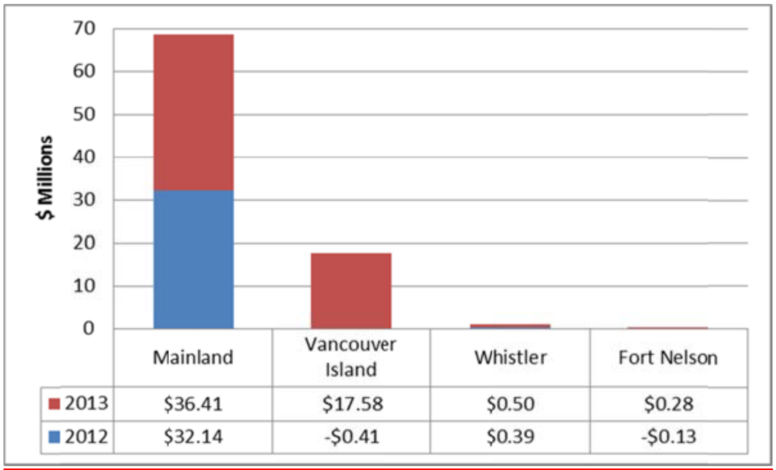
Original signed:

Diane Roy

Attachments

cc: Registered Parties

Figure 1.1-1: Forecast 2012 and 2013 Revenue Deficiencies for the FortisBC Energy Utilities[1]



The revenue deficiencies result in 2012 and 2013 delivery rate changes for Mainland, Whistler and Fort Nelson as shown in Table 1.1-1. There is no revenue deficiency in 2012 for Vancouver Island, as the forecast revenues at existing rates equal the forecast cost of service. In 2013, the forecast revenue deficiency is being offset by part of the projected December 31, 2012 surplus balance of $71.4 million (before tax) in the Rate Stabilization Deferral Account ("RSDA"). In this Application, Vancouver Island is seeking approval for a rate freeze for 2012 (which equals the forecast cost of service) and 2013.

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Table 1.1-1: Mainland, Whistler and Fort Nelson Delivery Rate Changes[2][3]

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Utility/Region	2012	2013	Total
Mainland	5.59%	6.29%	11.88%
Whistler	5.02%	6.54%	11.56%
Fort Nelson	-6.67%	14.98%	8.31%

Overall, the primary drivers for the revenue deficiencies and revenue surplus for Fort Nelson in 2012 are in the four categories described below.

1. Rate base growth

Increases in rate base are a major driver of the revenue deficiencies for 2012 and 2013. The 2012 and 2013 rate base amounts represent the investment by the Companies in utility assets necessary to provide service to our customers. 95 percent of the total FEU rate base of $3.6

1 Section 7.1 to 7.4, Schedules 2 and 3

2 Approximate delivery rate change percent is equal to the revenue deficiency divided by the forecast delivery margin revenue at existing 2011 delivery rates (i.e. excluding cost of gas).

3 Section 7.1 to 7.4, Schedule 14

billion is comprised of net gas plant in service (gross plant in service, less contribution in aid of construction, less accumulated depreciation relating to both, and negative salvage). The remaining portion of rate base consists of:

- work-in-progress not attracting allowance for funds used during construction;
- the mid-year balance of unamortized deferral accounts (regulatory assets and liabilities);
- the thirteen-month average of cash working capital and other working capital;
- mid-year future income tax asset and offsetting liability; and
- in the case of the Mainland, the LILO benefit arising from LILO agreements with several Interior municipalities.

The table below sets out the forecast rate base for 2012 and 2013, for each FortisBC Energy Utility.

Table 1.1-2: Rate Base in 2012 and 2013

Utility/Region, ($ thousands)	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 2,629,185	$ 2,753,641	$ 2,810,535
Vancouver Island	728,993	788,329	815,707
Whistler	42,594	42,046	41,346
Fort Nelson	6,839	7,438	9,291
	$ 3,407,611	$ 3,591,454	$ 3,676,879

The increases to rate base in 2012 and 2013 are a result of both regular capital expenditures, including the incremental capital related to the Long Term Sustainment Plan as discussed in section 1.2.4.3 below, and the implementation of large projects, such as the Mount Hayes LNG Facility, the Customer Care Enhancement ("CCE") Project, the Fraser River, Kootenay River, Muskwa River and Tilbury projects, and the recently approved Victoria Regional Operations Centre. Balances in the Energy Efficiency and Conservation and other deferral accounts are also significant contributors to changes in rate base. Offsetting these increases are reductions in Gas In Storage due primarily to lower commodity rates.

Increases to rate base increase the revenue deficiency primarily through the rate of return on assets and higher depreciation expense.

2. Increases to O&M (net of overheads capitalized)

O&M expenditures are influenced by a number of drivers with cost pressures coming from different sources including non-discretionary increases for inflation on internal labour and benefits, contracts and materials, increases in operating activities, and new business drivers and safety requirements. In particular, incremental funding requests are driven by the five cost drivers discussed in Section 5.2:

- Labour inflation and benefits;
- Codes and regulations spending, reflecting our continued focus on maintaining the safety and reliability of our system summarized in Section 1.2.4.1 and 1.2.4.2;
- Customer and stakeholder expectations, reflecting the in-sourcing of key customer service functions and meter reading cost increases in 2013 (summarized in Section 1.2.1), and also the implementation of our long term resource planning initiative;
- Demographic challenges; and
- Service standards and reliability, driven in part by our Long Term Sustainment Plan requirements summarized in Section 1.2.4.3.

The O&M increases due to each of these cost drivers are described in detail on a department-by-department basis in Section 5.2.

Offsetting these incremental funding requests in 2012, the Companies are forecasting savings as compared to 2011 from the implementation of the Harmonized Sales Tax ("HST"). A discussion of the ongoing uncertainty around the HST is included in Section 5.6 Taxes.

3. Increases in Other Revenue

Overall, the Companies are forecasting a significant increase in other revenue in 2012 and a further modest increase in 2013. For all of the FortisBC Energy Utilities, other revenue includes revenue from service work (connection charges), late payment charges, and returned cheques. In addition, the Mainland utility receives revenue for wheeling charges (from Vancouver Island), third party revenue on its Southern Crossing Pipeline, and starting in 2012, revenue from natural gas for transportation service. The Vancouver Island utility also receives revenue from the Mainland for LNG mitigation.

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4. Other Changes in Revenue Requirements

In this category includes:

- Demand changes driven by customer growth and changes in use rates - all regions are forecast to experience a slight increase in consumption except Whistler, where consumption is forecast to decline by 1 percent from 2012 to 2013;
- Increases to depreciation and negative salvage rates related to removal costs - an update to the depreciation study has been conducted, resulting in increases in both depreciation expense and estimates of negative salvage;
- Increases in property tax. Property tax has a moderate impact on revenue requirements over the two year period; and
- Decreases in interest and income tax rates and changes to the tax treatment of certain items, such as removal costs. The income tax rate has declined from 26.5 percent in 2011 to 25 percent in 2012 and the forecast of short-term interest rates has declined from what was included in the 2011 rates.

The rates sought for each utility and the particular cost drivers affecting each utility are discussed in the following paragraphs. In addition to the delivery rate increases summarized below, with this Application FEI, Fort Nelson and FEW are also requesting changes to the Revenue Stabilization Adjustment Mechanism ("RSAM") Rider for 2012.

FORTISBC ENERGY INC.

Changes to the FEI revenue requirements result in revenue deficiencies of $32.1 million in 2012 and $36.4 million in 2013. These deficiencies are summarized in Figure 1.1-2 below.

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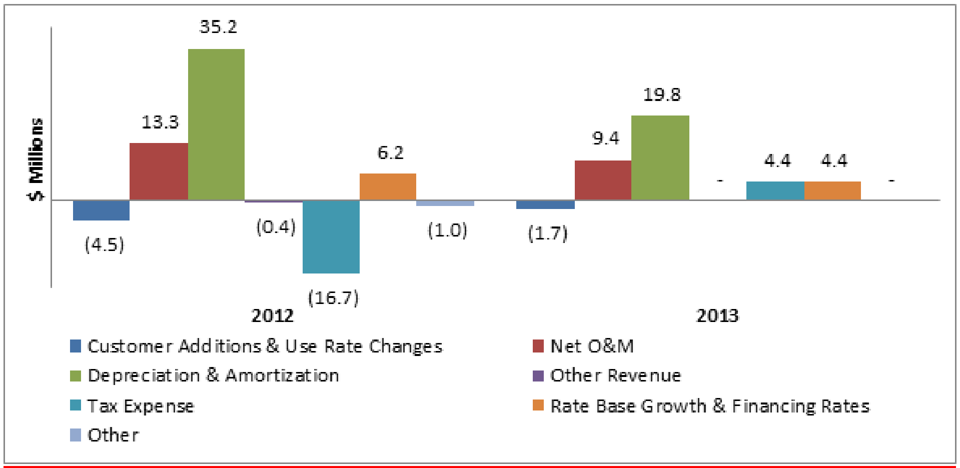
Figure 1.1-2: Mainland Revenue Deficiency Components[4]



The primary drivers of the revenue deficiencies in FEI are rate base and depreciation growth resulting from the implementation of significant capital projects related to system integrity and reliability (including the Fraser and Kootenay River Crossings, the Tilbury Property Purchase and the capital related to the Long Term Sustainment Plan) and our customer care enhancement solution, as well as inflationary pressures on costs, a heightened focus on the safety and security of our gas systems, and our ongoing and growing compliance requirements related to codes and regulations. FEI has continued to manage its costs appropriately in the face of increasing cost pressures, and FEI believes that the costs reflected in the proposed rates are reasonable.

Based on these revenue deficiencies, FEI is seeking an increase in its rates for delivery service of 5.6 per cent in 2012, with an additional increase of 6.3 per cent in 2013 (cumulative increase of 11.9 per cent over two years). The delivery charge is only one component of a customer's total bill. For an average Lower Mainland residential customer, this delivery rate increase results in changes to the annual bill of 2.8 per cent or $27 in 2012 and an additional 3.2 per cent or $31 in 2013.[5] Including the removal of the Earnings Sharing Mechanism rider and an offsetting reduction to the RSAM rate rider, the FEI annual bill impact would be a larger increase, of 3.2 per cent or $30 in 2012.

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4 Section 7.1, Schedule 1
5 Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on current commodity and midstream charges effective October 1, 2011 and excludes the impacts of rate riders.

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FORTISBC ENERGY WHISTLER INC.

Changes to the Whistler revenue requirements result in revenue deficiencies of $387 thousand in 2012 and $496 thousand in 2013. These deficiencies are summarized in Figure 1.1-3 below.

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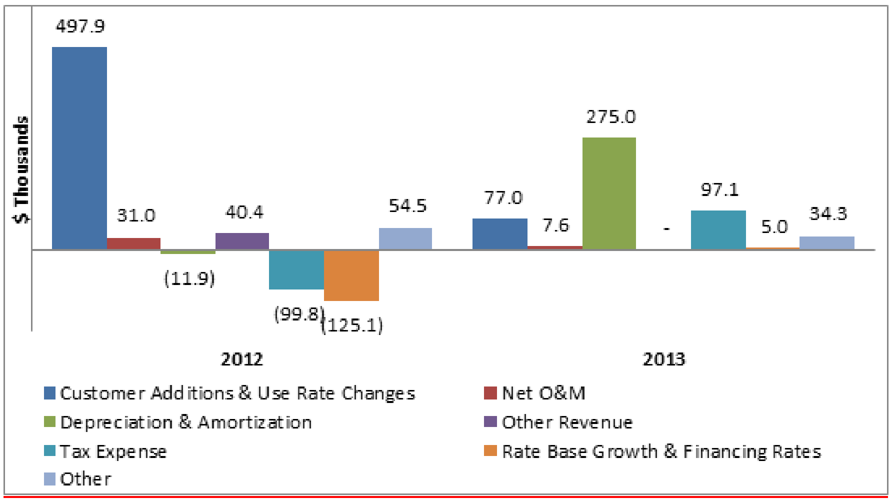
Figure 1.1-3: Whistler Revenue Deficiency Components[6]



In FEW, the primary driver of the revenue deficiencies is a reduction in the total demand forecast for 2012 and 2013, which is offset in large part in 2012 by the one year amortization of credit balances in deferral accounts.

Based on these revenue deficiencies, FEW is seeking an increase in its rates for delivery service of 5.0 per cent in 2012, with an additional increase of 6.5 per cent (cumulative increase of 11.6 per cent) in 2013. This results in an increase to the annual bill of an average Whistler residential customer of 3.3 per cent or $49 in 2012 and an additional 4.3 per cent or $64 in 2013.[7] Adding in the increase from the RSAM rate rider, the FEW annual bill impact would be an increase of 6.5 per cent or $96 in 2012.

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[6] Section 7.3, Schedule 1

[7] Based on a typical annual consumption of a Whistler residential customer consuming 90 GJ. This is also based on current commodity and midstream charges effective October 1, 2011 and excludes the impact of rate riders.

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FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA

Changes to the Fort Nelson revenue requirements result in revenue surplus of $125 thousand in 2012 and a revenue deficiency of $283 thousand in 2013. These amounts are summarized in Figure 1.1-4 below.

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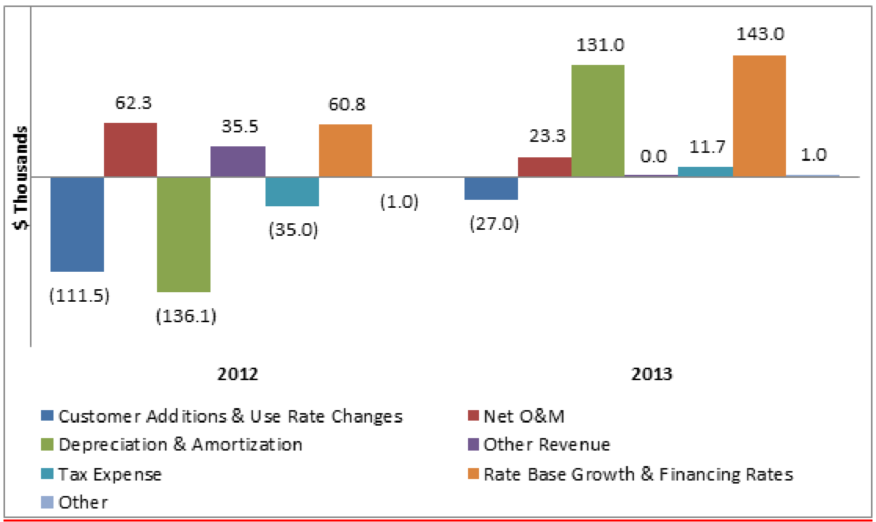
Figure 1.1-4: Fort Nelson Revenue Deficiency Components[8]



The primary driver behind the 2012 revenue surplus in Fort Nelson is the amortization of the credit balance in the Muskwa River Crossing 2011 deferral account. The 2013 revenue deficiency in Fort Nelson is attributable to the necessary replacement of the Muskwa River Crossing that is expected to be complete mid 2012.

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Fort Nelson is seeking a decrease in its rates for delivery service of 6.7 per cent in 2012, with an additional increase of 15.0 per cent (cumulative increase of 8.3 per cent) in 2013. This results in a decrease to the annual bill of an average Fort Nelson residential customer of 2.6 per cent or $26 in 2012 and an increase of 5.9 per cent or $60 in 2013.[9] Including a reduction to the RSAM rate rider, the Fort Nelson annual bill impact would be a decrease of 3.2 per cent or $32 in 2012.

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FORTISBC ENERGY VANCOUVER ISLAND INC.

A revenue surplus of approximately $0.4 million is forecast for 2012 for Vancouver Island; the $40.1 million deficiency that results from the loss of royalty revenues is offset by a $27 million reduction in the cost of gas and $8.1 million in amortization of the Gas Cost Variance Account ("GCVA"). The revenue

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8 Section 7.4, Schedule 1
9 Based on a typical annual consumption of a Fort Nelson residential customer consuming 140 GJ. This is also based on current commodity charges effective October 1, 2011 and excludes the impact of rate riders.

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deficiency in 2013 of $17.6 million is attributable to an increase in the cost of gas, the removal of the one-year amortization of the GCVA, and tax expense and earned return increases, as displayed in Figure 1.1-5.

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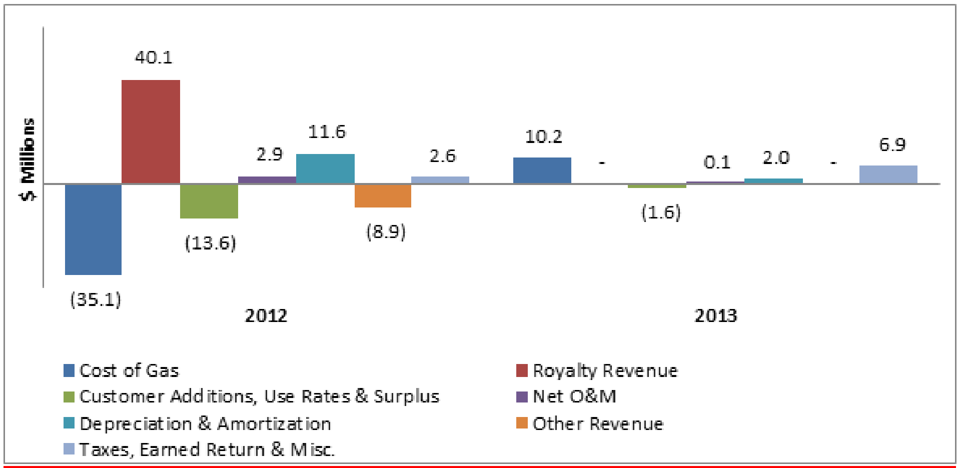
Figure 1.1-5: Loss of Royalty Revenues Offset by Reduction in Cost of Gas in 2012[10]



FEVI is seeking to maintain current rates for all customers except those with specified rates in their transportation service agreements, for a two-year period commencing January 1, 2012. Consistent with the intended purpose of the RSDA, FEVI proposes to use part of the surplus to maintain rates at the 2011 level for 2013. The RSDA was approved as part of the last FEVI revenue requirements application, with the intention of using the accumulated balance to manage cost pressures unique to FEVI. The rate proposal in the present Application implements the previously developed strategy.

THE FORTISBC ENERGY UTILITIES - COMBINED COST OF SERVICE FOR 2013

Later this year, the FEU intend to seek the necessary approvals to amalgamate effective January 1, 2013 and to introduce harmonized rate structures effective on the same date. As the anticipated effective date of amalgamation and harmonized rates falls within this two year revenue requirements period, the orders sought in respect of 2013 rates for the individual entities have been expressed as being conditional upon amalgamation and harmonized rates not taking effect. And, in anticipation of the upcoming application to amalgamate and introduce harmonized rates, the FEU are collectively applying in the present Revenue Requirements Application for approval of the amalgamated utility cost of service for 2013. The FEU believe that this is the most efficient way to proceed and the order approving an amalgamated cost of

[10] Section 7.2, Schedule 1

1.2.1 IN-SOURCING OF KEY CUSTOMER SERVICE FUNCTIONS

In Commission Order No. C- 1-10, FEI received approval to in-source key components of customer care services and implement a new Customer Information System ("CIS") through the Customer Care Enhancement Project ("CCE Project"). The CCE Project is progressing on time with an implementation date of January 1, 2012, and the overall project spend remains on track with no variance to the approved spend of $115.5 million.

As a result of the implementation of the CCE Project, the Customer Service department has been created to manage the contact centres (located in Burnaby and Prince George), the revenue cycle and billing operations, customer relations, bad debt expenditures, and meter reading services. Overall, the 2012 forecast costs for the Customer Service department show a decline of approximately $1.9 million from the 2011 approved amount, as savings are recognized with the transition to the in-sourced service delivery model. In Section 5.3.7 of this Application, the ongoing services and operating expenses for the Customer Service Department are described in detail, as well as the Utilities' plan to maintain existing service quality measures for the two years of this RRA.

Also, in Section 6.3, a deferral account is requested to capture actual expenditures that differ from the forecast 2012 and 2013 O&M expenditure levels for many of the Customer Service functions. The types of uncertainties that the deferral account will address include fluctuations in call volumes, the rate of customer adoption of new communication channels and self serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, and any variances in the anticipated duration required for new staff to become skilled and proficient at their responsibilities. The variance account will also capture spending variances in meter reading costs primarily due to the timing of BC Hydro's Smart Metering Initiative and its impact on joint gas/electric meter reads in 2012 and the uncertainty of costs in 2013. These cost variances are largely beyond the control of the Companies and the use of deferrals will avoid the potential for windfall gains or losses to customers or the shareholder during the transition period.

1.2.2 ENHANCED ENERGY EFFICIENCY AND CONSERVATION PROGRAMS

As part of the 2010-2011 RRA, FEI and FEVI received approval to increase their investment in Energy Efficiency and Conservation ("EEC") to add programs for Interruptible Industrial customers and Innovative Technologies, to reallocate funding to Affordable Housing initiatives, and for additional funding to implement programs until the end of 2011, and an extension of the funding approved by the Commission in the EEC Decision of April 2009. This brought the total funding for EEC activities to $31.0 million in 2010 and $35.3 million in 2011. Of this approved expenditure, FEU spent $10.0 million in 2010 and is projecting to spend $16.8 million in 2011, excluding NGV incentives.

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The 2010 Conservation Potential Review ("CPR") identified significant potential for EEC programs see Appendix K-2, and supports an expansion of EEC initiatives for the benefit of customers. In this Application the FEU are proposing an increase in the allowed funding envelope for 2012 and 2013 to $64.5 million in total for each year. This increase consists of increased budgets for previously-approved program areas (including "conventional" EEC programs and funding for Innovative Technologies), expansion of EEC programs to the Whistler service area, offering industrial programs to FEVI customers, as well as new initiatives such as the Furnace Scrap-It Program.

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The amounts requested for 2012 and 2013 represent a significant increase in the funding envelope relative to 2011. However, the increased amount is supported by the CPR and all expenditures will continue to be evaluated according to Commission-approved mechanisms to ensure that they are beneficial. Also, the FEU are proposing a change in the methodology for recovery of EEC expenditures from customers such that only a base level of spending ($20 million per year) is included in rate base for 2012 and 2013. Expenditures incurred over and above the base level will be placed in a non rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014. The change in methodology is discussed in Section 6.3.2.1, and the details of all planned EEC expenditures are included in Appendix K-1. The FEU believe that the approach of increasing the overall funding envelope for cost-effective programs, while establishing the proposed financial treatment best ensures that FEU can maximize the benefits of EEC programs for customers in a manner that is fair to customers and the Companies.

FEU's ultimate intention is to obtain approval for a long term funding request. The FEU's long term EEC funding request for 2014 and beyond will be made in the FEU Long Term Resource Plan that will be filed with the Commission in 2013. The approvals sought in the present Application will provide the necessary continuity until that long-term request can be made.

1.2.3 EXPANDED SERVICE OFFERINGS FOR CUSTOMERS

The FortisBC Energy Utilities are providing expanded service offerings for customers in the areas of Biomethane, CNG and LNG Fueling, and Alternative Energy Services (now being referred to in this Application by the more descriptive term "Thermal Energy Services"). The costs and revenues associated with the Biomethane and Natural Gas for Transportation programs form part of FEI's natural gas business, and have been included in the forecasts included in this Application. In FEI's 2010-2011 Revenue Requirements Application, the necessary accounting structures were put in place to separate FEI's Thermal Energy Services line of business from the natural gas business. As a result of the approval of that application for FEI, the activities in the area of Thermal Energy Services are captured in a non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in this Application. As a result, there is a reduction in the O&M included in the natural gas cost of service that is associated with the recovery of overheads from the Thermal Energy Services line of business. In the long-run, the more successful the Thermal Energy Services business becomes, the greater the potential benefit to natural gas customers in terms of a recovery of overheads. Each of the three service offerings is discussed below.

On April 13, 2010, FEI submitted to the Commission and Interveners our Final Written Reply Submission, and at the time that this RRA was submitted the NGV Application was still before the Commission for approval. Given customer support[11] for the NGV Application and our belief that this is part of our core business, we have included in this RRA our project costs and revenue to undertake this business for 2012 and 2013. Thus these impacts have been integrated into our other revenue forecasts (Section 5.5), O&M (Section 5.3), capital expenditures (Section 6.2) and rate base deferral (Section 6.3) for the 2011 CNG and LNG Service Costs and Recoveries.

In the recent NGV Application, FEI requested approval for an ongoing rate base deferral account to capture incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand. Further, in this Application, FEI is seeking approval to expand this account to include variations from the revenue forecast pertaining to Rate Schedule 16 of $1.1 million in 2012 and $1.1 million in 2013. FEI has included a comprehensive report in Appendix I summarizing the costs incurred and deferred in 2010 and 2011 related to the program, and also providing a summary of the forecast program costs and revenues that are included in each of Sections 5.5, 5.3, 6.2, and 6.3.

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The growth of the NGV fueling business is inherently reliant upon the adoption of NGVs in our service territory and the Utilities believe that the adoption of NGVs in our service territory is inherently reliant upon the continued availability of these EEC incentives for NGV adoption during the term of the revenue requirement. The Utilities wish to make clear that the provision of cost-effective EEC incentives to fleet operators is not pre-conditioned on any requirement that the Utilities own and operate the NGV refuelling stations to supply the acquired vehicles. It does however require that it be allowed to make that option available to prospective fleet operators in order to see the NGV adoption required to provide meaningful and material benefit to our existing customers. Discontinuance of EEC incentives for NGV's will represent a significant barrier to achieving the objective of adding NGV throughput to the system for the benefit of all existing customers.

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1.2.3.3 Thermal Energy Services

FEI and FEVI, in their respective 2010-2011 Revenue Requirements Applications, requested approval of tariff provisions to permit them to provide Alternative Energy Solutions ("AES"), which included Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the applications. The Companies are now using the more descriptive term "Thermal Energy Services" to encompass these same services. The Negotiated Settlement Agreement for FEI's 2010-2011 RRA, approved by BCUC Order No. G-141-09, acknowledged that FEI would be engaged in Thermal Energy Services (or AES). The Negotiated Settlement

[11] Final Submission Arguments from Registered Interveners BCSEA, BCOAPO, and CEC generally support the proposed NGV Application.

Energy Services have been segregated and allocated to the Thermal Energy Services line of business. FEI activities in the area of Thermal Energy Services will continue to be captured in the approved non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in this Application. There is also a reduction in the O&M included in the natural gas cost of service (i.e. a benefit to natural gas customers) that is associated with the recovery of overheads from the Thermal Energy Services line of business. This is discussed further in Appendix G.

The growing prevalence of thermal solutions such as solar, DES and geo exchange, regardless of the provider of those services, will have an increasingly significant impact on the natural gas requirements over time. Thus, from the perspective of natural gas customers it is important to understand the growth of these energy alternatives over time and how they may impact the natural gas throughput and utilization. FEU sees this as an important issue to address in future filings such as the Long Term Resource Plan and future Rate Design applications. The need for additional resources to examine these impacts as part of the long term integrated resource planning process is discussed further in Section 5.3.8.

1.2.4 INCREASED FOCUS ON INVESTMENTS TO MAINTAIN THE SAFETY AND RELIABILITY OF OUR SYSTEM

In our 2010-2011 RRAs, we requested increases to O&M and capital budgets to ensure ongoing compliance to existing codes and anticipated new or changed codes and to allow us to continue to invest in the safety, integrity and reliability of the energy delivery system. To address these requirements, we received approval for additional O&M in the amount of $5.3 million in 2010 and a further $2.1 million in 2011. This funding allowed us to enhance safety messaging for customers, begin the long-range asset planning and address the specific code changes that were required. How each of these three areas has evolved since then is discussed below. The FEU believes that continued funding in these areas is necessary to ensure safe and reliable natural gas service.

1.2.4.1 Codes & Regulations

In addition to the codes and regulations that were addressed in 2010 and 2011, the FEU have identified new codes and regulations, and changes to existing codes and regulations that need to be addressed. A further discussion of these specific codes and regulations and incremental funding of $1.8 million in 2012 and a further $0.9 million in 2013 to address these requirements is included in O&M Section 5.3.

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Two other areas where the Utilities need funding to address safety and system integrity are:

- The BCOneCall project - a multi-stream two and a half year project that will automate a portion of the BCOneCall process and allow for the realization of significant benefits immediately upon completion of the project; and

In Section 6.2, FEU describes sustainment capital spending for a total of $85.0 million in 2012 and $89.6 million in 2013 that it seeks approval for. These forecast amounts represent incremental spending, excluding CPCN projects, of $25.6 million and $30.2 million in 2012 and 2013 respectively over 2011 approved amounts for the same purpose. FEU believes that the forecast expenditures strike an appropriate balance between the risks to health, safety, system integrity, and property, with rate impacts and many other factors.

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Over the longer term, FEU will continue to improve its asset management practices with the further development of a Long Term Sustainment Planning process. The LTSP will help us analyze a myriad of factors impacting asset replacement decisions and be used to prioritize spending where necessary and help to minimize the impact on rates by spreading costs out over time.

In summary, FEU must continue to address the critical issue of aging infrastructure and asset management in an evolving business environment. FEU believe the programs and expenditures included in this RRA are prudent and in the best interest of customers.

1.2.5 RATE MITIGATION STRATEGY FOR VANCOUVER ISLAND: AMALGAMATION AND HARMONIZED RATE STRUCTURE

In the 2010-2011 RRA for Vancouver Island, we developed and received approval for an interim rate mitigation strategy to help to offset the immediate rate pressure that would otherwise result from the loss of the forecast $40 million of revenues ("Royalty Revenues") provided to FEVI by the Provincial Government that partially offset the cost of gas on Vancouver Island. This interim strategy resulted in a rate freeze for core market customers at a level that exceeded the cost of service and the creation of a Rate Stabilization Deferral Account, to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. The balance in the RSDA would then be used after 2011 to offset future rate increases. However, the balance in the RSDA is insufficient to offset the increased rate pressure for more than a short period of time. FEVI has long recognized that a permanent solution is required, and that the real solution will take the form of amalgamation of the Companies and the implementation of a harmonized rate structure. FEU's intention is to file an application in the Fall of this year seeking approval to amalgamate the Companies effective January 1, 2013 and approval of a harmonized or "postage stamp" rate structure.

In this Application, we have presented the revenue requirement information for each of the FEU separately for 2012 and 2013, and are seeking approval of rates for each company separately. FEVI's revenue requirement for 2013 reflects the utilization of part of the RSDA balance. However, as the intention is to amalgamate the entities half-way through the RRA period, the FEU have also taken the additional step in this Application of presenting an amalgamated cost of service based on the assumption that the three companies will be amalgamated effective January 1, 2013. The Companies are seeking approval of the amalgamated cost of service, which would only be employed if and when the FEU later obtain the necessary approvals to amalgamate and to implement harmonized rates. The amalgamated cost of service, once

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a non rate base deferral account to capture any differences that arise from the implementation of FIN 48.

3.2.2.3 Other US GAAP Items

A number of other adjustments are contemplated on transition to US GAAP that should not affect cost of service or rate base. These potential adjustments include the application of pushdown accounting, adjusting for how FEI accounts for Lease In/Lease Out transactions for external financial reporting, and others. None of these transactions are expected to affect regulatory accounting or reporting and would not affect the revenue requirement.

3.2.2.4 Costs Associated with the Adoption of US GAAP

In their US GAAP Application, the FEU outlined the expected costs of adopting both IFRS and US GAAP. The costs of adopting US GAAP were estimated to be incremental one-time costs of $1.5 million (before tax) and on-going costs of $0.7 million. These one-time costs are generally as a result of audit fees on the adoption of US GAAP. The on-going costs are also as a result of audit fees. These costs have not been included in this application. Under a US GAAP adoption scenario, the FEU would include the recovery of these costs through an evidentiary update to this RRA.

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3.2.3 SUMMARY OF STATUS OF GAAP

In summary, upon receipt of a decision in the US GAAP Application, the FEU will provide an evidentiary update.

If the US GAAP Application is approved as proposed, the FEU will update their Application to include:

1. A total decrease in cost of service from pension and OPEBs (decrease of $782 thousand in 2012 and $2.24 million in 2013 as shown in Table 3.2-1 above) plus any associated income tax impacts;
2. The changes to rate base resulting from the pension and OPEB deferrals discussed in Section 3.2.2.1,
3. A total decrease in O&M of $0.2 million in each of 2012 and 2013 for the ongoing costs of US GAAP compliance; and
4. A rate base deferral to capture the estimated $1.533 million (before tax) in one-time US GAAP conversion costs.

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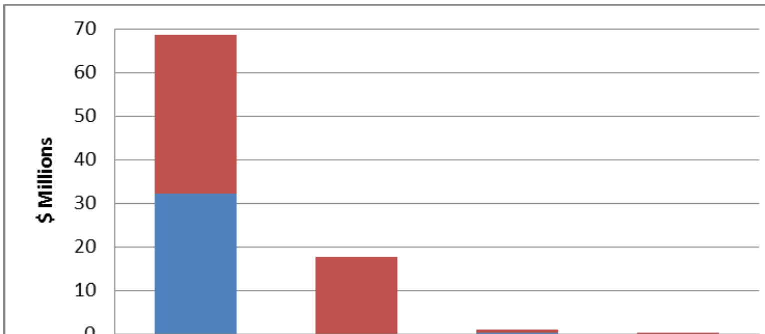
In the event that the FEU are ordered to implement accounting policies other than US GAAP, the FEU will update their Application to include the impacts of those changes.

3.3 Summary of Revenue Requirements for 2012 and 2013

The revenue requirements reflect all of the inputs in the financial schedules, and take into consideration all of the impacts described in this Application. The revenue requirement changes that the Companies are requesting are based on sound research and forecasting, using our knowledge and experience to determine what the Companies believe is the likely course of events over the upcoming forecast periods of 2012 and 2013.

The following figure provides the 2012 and 2013 revenue deficiencies for the FortisBC Energy Utilities. The revenue deficiency or surplus is determined by comparing the forecast cost of service to the forecast revenue at existing 2011 rates for each year.

Figure 3.3-1: Forecast 2012 and 2013 Revenue Deficiencies for the FortisBC Energy Utilities[20]



	Mainland	Vancouver Island	Whistler	Fort Nelson
2013	$36.41	$17.58	$0.50	$0.28
2012	$32.14	-$0.41	$0.39	-$0.13

The revenue deficiencies result in 2012 and 2013 delivery rate changes for Mainland, Whistler and Fort Nelson as demonstrated in Table 3.3-1. The forecast revenue deficiency for Vancouver Island in 2013 is being offset by part of the projected December 31, 2012 surplus balance of $71.4 million (before tax) in the RSDA. In this Application, Vancouver Island is seeking approval for a rate freeze for 2012 (which approximately equals the forecast cost of service) and 2013 and the continuation of the RSDA mechanism for 2012 and 2013.

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[20] Section 7.1 to 7.4, Schedule 2 and 3

Table 3.3-1: Revenue Deficiencies in Mainland, Whistler and Fort Nelson Result in Delivery Rate Increases[21],[22]

Utility/Region	2012	2013	Total
Mainland	5.59%	6.29%	11.88%
Whistler	5.02%	6.54%	11.56%
Fort Nelson	-6.67%	14.98%	8.31%

An explanation of the forecast 2012 and 2013 revenue deficiencies and rate proposals by Utility is provided in the following sections.

3.3.1 SUMMARY OF MAINLAND REVENUE REQUIREMENTS

The total revenue requirements of $1,248.3 million in 2012 and $1,285.6 million in 2013 have been calculated appropriately and reflect the reasonable costs required for FEI to continue to meet the needs of our customers and the communities in which we serve. The following sub-sections will discuss the total Mainland revenue requirement and revenue deficiencies for 2012 and for 2013.

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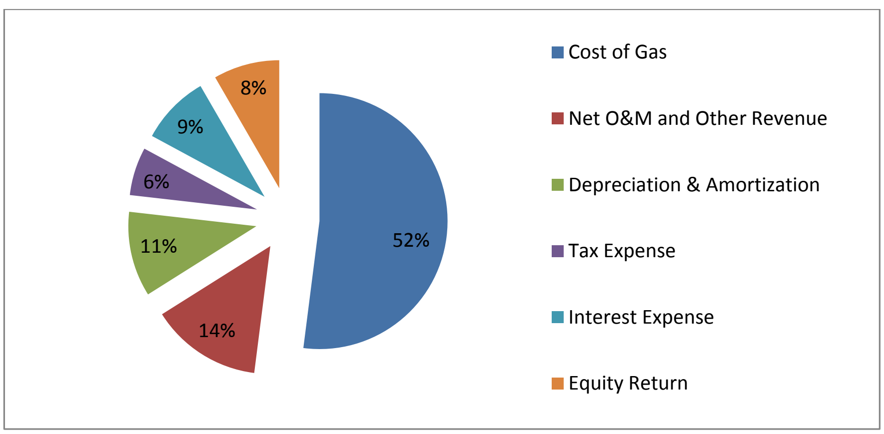
Figure 3.3-2 provides a breakdown of the components of the Mainland total revenue requirement averaged for the two year period.

Figure 3.3-2: Average Composition of the 2012 and 2013 Mainland Revenue Requirement[23]



[21] Approximate delivery rate change percent is equal to the revenue deficiency divided by the forecast delivery margin revenue at existing 2011 delivery rates (i.e. excluding cost of gas).
[22] Section 7.1 to 7.4, Schedules 2 and 3
[23] Section 7.1, Schedule 5 and 6

Changes to the Mainland revenue requirements result in revenue deficiencies of $32.1 million in 2012 and $36.4 million in 2013. These deficiencies are summarized in Figure 3.3-3 below.

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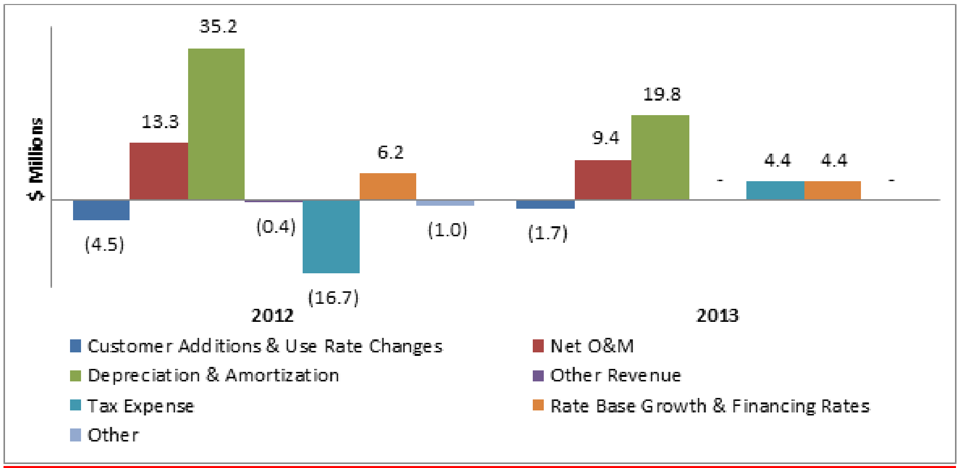
Figure 3.3-3: Mainland Revenue Deficiency Components[24]



3.3.1.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4 is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The non-bypass customer demand determined in Section 4 is 1,859 TJs greater than the demand forecast embedded in 2011 delivery rates, with a further increase of approximately 215 TJs in 2013. This increase in demand is attributable to customer growth and reflects changes in use rates and results in a revenue surplus of approximately $4.5 million in 2012 and $1.6 million in 2013. The table below shows the changes in demand by customer group for 2012 and 2013.

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[24] Section 7.1, Schedule 1

Table 3.3-2: Increased Demand for 2012 and 2013[25]

Non-Bypass Volume Change, TJ	Forecast 2012	Forecast 2013
Residential	1,311	(74)
Commercial	(1,864)	(61)
Other	(835)	3
Total Sales	(1,388)	(132)
Rate 22 Firm	1,318	(127)
Rate 22 Interruptible	1,147	76
Rate 23	974	334
Rate 25	(403)	57
Rate 27	211	7
Total Transportation	3,247	347
Total Non-Bypass Volume Change	1,859	215

The Demand Forecast and Revenue at Existing Rates and have been properly incorporated in the calculation of the Company's revenue requirement.

3.3.1.2 Cost of Gas

As discussed in Section 5.2, the commodity cost recovery charge and the midstream cost recovery charge for the natural gas sales rate customers are subject to quarterly review by the Commission, and Mainland is not requesting approval of forecast gas costs with this Application. Forecast gas costs are required in the determination of working capital and correspondingly rate base and earned return. The cost of gas itself does not impact the determination of the revenue deficiency or surplus because the revenue at existing rates includes commodity and midstream revenue that fully offsets the forecast cost of gas.

3.3.1.3 Operations and Maintenance Expenses

As discussed in Section 5.3, the 2012 and 2013 O&M expense forecasts have been developed in support of the Companies' business priorities and objectives, ensuring that O&M funding is appropriate and prioritized to meet the current and longer-term needs of customers. Key priorities and focus for the utilities in the near future include customer service repatriation; public and employee safety, customer satisfaction, financial management, environmental responsibility and system sustainment, and the demographic challenges we face with our aging workforce. The business drivers and their impacts on forecast O&M in 2012 and 2013 are summarized in

[25] Increase as compared to demand forecast embedded in 2011 rates, Section 7.1, Schedules 7 to 9

the figure below. As shown in Figure 3.3-4, the impact of changes in the O&M is an increase to the revenue requirements of $13.3 million in 2012 and $9.4 million in 2013, net of capitalized overhead.

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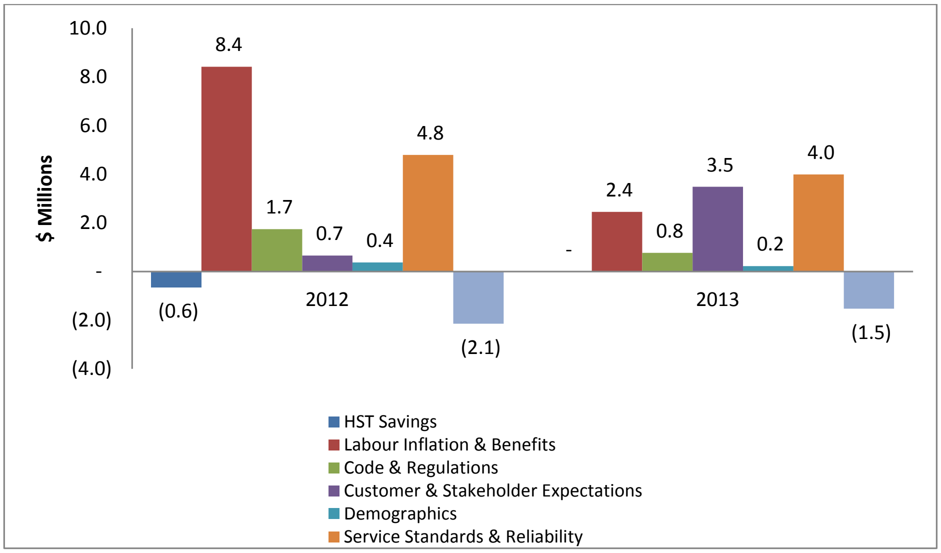
Figure 3.3-4: O&M Funding Results in Increased Revenue Requirements[26]



The items in the figure above are discussed more fully in Section 5.3, and have been properly reflected in the calculation of the Company's revenue requirement.

3.3.1.4 Depreciation and Amortization Expense

As discussed in Section 5.4, an update to the depreciation study has resulted in an increase to depreciation expense of $4.6 million. Additions in 2012 and 2013 have resulted in higher depreciation expense of $13.9 million in 2012 and a further $5.1 million in 2013. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of all depreciation changes is an increase of $24.7 million in 2012 and a further $6.8 million in 2013.

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The removal cost provision has increased $4.9 million in 2012 and a further $0.6 million in 2013. Similar to depreciation expense, the removal cost provision is not deductible for income tax purposes; therefore, the total revenue requirement impact of the removal cost provision is $6.5 million in 2012 and a further $0.8 million in 2013.

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[26] Please refer to Section 5.3, Table 5.3-6 and Table 5.3-7

In addition, amortization expense has increased $4.0 million in 2012 and a further increase of $12.3 million in 2013. Both of these amounts are after-tax, so the impact to revenue requirements is as stated. The three accounts listed in Table 3.3-3 are the key contributors to the increase in amortization expense in 2012 and are accounts that did not have amortization expense in 2011.

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Table 3.3-3: Accounting Impacts Drive Amortization Expense Increases in 2012[27]

Amortization Expense ($ millions)		2012
Deferred Removal Costs		1.5
Gains and Losses on Asset Disposition		0.6
2010-2011 Customer Service O&M		3.0
	$	5.0

The increase in 2013 amortization expense is largely driven by deferral accounts that had credit balances in 2011 and were fully amortized in 2012, such as the Property Tax Variance, Insurance Variance and Tax Variance accounts. The five accounts listed in Table 3.3-4 are the key contributors to the 2013 increase of $12.3 million in amortization expense.

Table 3.3-4: Amortization Expense Increases in 2013[28]

Deleted: Change in Property Tax, Insurance and Tax Variance Accounts Drive

($ millions) Amortization Expense	2012	2013	Change
Property Tax Variance Account	$ (1.1)	$ (0.4)	$ 0.7
Insurance Variance Account	(1.2)	-	1.2
Tax Variance Account	(7.0)	-	7.0
Interest Variance Account	(2.5)	(1.7)	0.8
Energy Efficiency and Conservation	2.2	3.5	1.3
	$ (9.6)	**$ 1.4**	**$ 11.0**

The total impact on revenue requirement of changes in depreciation (including removal costs) and amortization is an increase of $35.2 million in 2012 and $19.9 million in 2013

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27 Section 7.1, Schedules 68 to 71
28 Section 7.1, Schedules 28 and 29

3.3.1.5 Other Revenues

As discussed in Section 5.5, an increase in Other Revenue of $0.4 million in 2012 and no change in 2013 is forecast. Increases in other revenue decrease the revenue requirement, offsetting the revenue deficiency. The increase in other revenue is largely attributable to revenue from natural gas for transportation service.

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3.3.1.6 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax decrease of $0.6 million in 2012 and an increase of $1.6 million in 2013 both affect revenue requirements. Other changes to income tax rates and adjustments to taxable income result in a decrease in revenue requirements in 2012 of $16.1 million and an increase in 2013 of $2.8 million . As shown in Table 3.3-5, the increase in CCA deductions, along with the deduction of removal costs and the reduction in the tax rate are the key components of the decrease in tax expense in 2012. The increase in CCA deductions is driven by the CCE Project. Changes in amortization and earned return are the key contributors to the tax expense increase in 2013.

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Table 3.3-5: Components of 2012 and 2013 Tax Expense Changes[29]

($ millions)	2012	2013	Total
Reduction in Tax Rate	$ (2.0)	$ (0.4)	$ (2.4)
Increase in CCA Deductions	(12.6)	(1.8)	(14.4)
Removal Cost Deduction	(5.0)	0.3	(4.7)
Pension and OPEB	0.6	(0.7)	(0.1)
Changes in Amortization Expense	1.2	4.4	5.6
Changes in Earned Return	1.7	0.8	2.5
Other	-	0.2	0.2
	$ (16.1)	$ 2.8	$ (13.3)

3.3.1.7 Earned Return – Return on Rate Base and Financing Costs

Mainland earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.8 per cent of that change. The rate base proposals contained in Section 6, Rate Base contribute $4.7 million to the 2012 revenue requirement and a further $2.2 million to the 2013 revenue requirement.

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The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Section 5.7, Financing Costs and Return on Equity. The amount of financing

[29] Section 7.1 to 7.4, Schedules 30 to 35. This calculation excluded the tax expense impact of depreciation expense and removal provision which is captured in Section 3.3.1.4

required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. The growth in rate base increases financing costs by $4.4 million in 2012 and $0.8 million in 2013. This is offset in 2012 by a reduction in interest rates, mitigating this impact by $2.9 million with an increase of $1.4 million in 2013, resulting in a net increase associated with financing costs of $1.5 million in 2012 and an increase of $2.2 million in 2013.

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The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing non-bypass delivery rates.

3.3.2 SUMMARY OF VANCOUVER ISLAND REVENUE REQUIREMENTS

The FEU believe that the total revenue requirements of $193.7 million in 2012 and $212.9 million in 2013 have been calculated appropriately and reflect the reasonable costs required for FEVI to continue to meet the needs of our customers and the communities in which we serve. The following sub-sections will discuss the total Vancouver Island revenue requirement and revenue deficiency for 2013.

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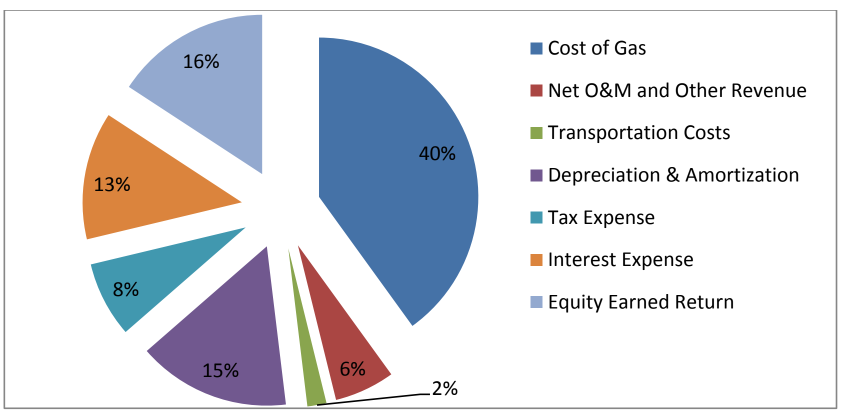
Figure 3.3-5 provides a breakdown of the components of the Vancouver Island total revenue requirement averaged for the two year period.

Figure 3.3-5: Average Composition of the 2012 and 2013 Vancouver Island Revenue Requirement[30]



[30] Section 7.2, Schedules 5 and 6

A revenue surplus of $0.4 million is forecast for 2012; the $40.1 million deficiency that results from the loss of royalty revenues is offset by a $27 million reduction in the cost of gas and $8.1 million in amortization of the GCVA. The revenue deficiency in 2013 of $17.6 million is attributable to an increase in the cost of gas, the removal of the amortization of the GCVA, and tax expense and earned return increases, as displayed in Figure 3.3-6.

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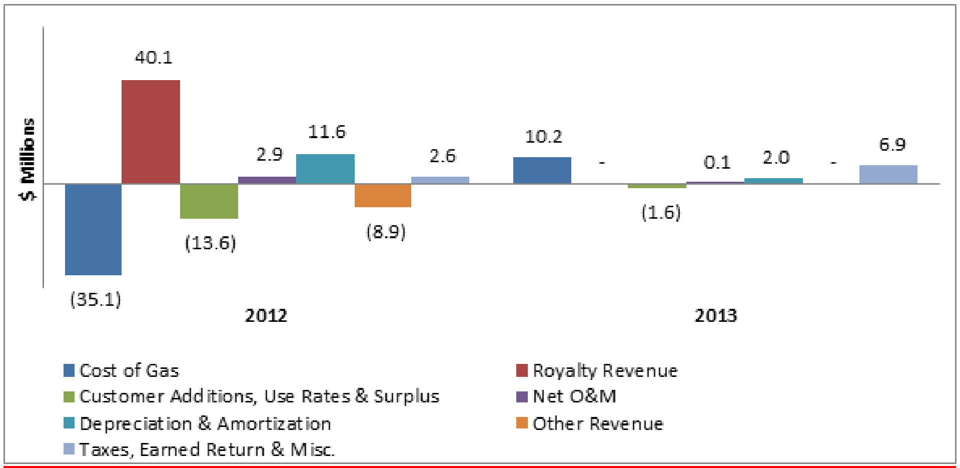
Figure 3.3-6: Loss of Royalty Revenues Offset by Reduction in Cost of Gas in 2012[31]



3.3.2.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4, is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 659 TJs lower than the demand forecast embedded in 2011 rates, with an increase of approximately 86 TJs in 2013. This decrease in demand is attributable to a reduction in use rates that is not offset by customer growth and results in a revenue deficiency of approximately $8.8 million in 2012 and a surplus of $1.6 million in 2013. In addition to the impacts of customer additions and use rates, the existing rates for Vancouver Island have the 2011 approved revenue surplus of approximately $22.4 million embedded within them, providing a net surplus associated with revenues at existing rates of $13.6 million in 2012 and $1.6 million in 2013.

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The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and has been properly reflected in the calculation of the Company's revenue requirement.

[31] Section 7.2, Schedule 1

3.3.2.2 Cost of Gas

As discussed in Section 5.2, Vancouver Island's cost of gas reflects the costs related to commodity, transportation, and storage resources and the impacts of the hedging program. The Royalty Rebate arrangement under which Vancouver Island has received royalty revenues from the Province expires on December 31, 2011; therefore, the 2012 and 2013 forecast cost of gas does not include any royalty revenues. All else equal, the loss of the royalty revenues results in an approximate revenue deficiency of $40.1 million in 2012. As shown in Table 3.3-6, the revenue deficiency of $40.1 million associated with the loss of the royalty revenues is offset by a reduction in the cost of gas and the amortization of the GCVA, for a combined net increase to the revenue requirement of approximately $5.0 million in 2012. With the GCVA fully amortized, the impact of cost of gas to the revenue requirement in 2013 is an increase of approximately $10.2 million.

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Table 3.3-6: Reductions in Commodity Costs Offset the Deficiency Associated with Royalty Revenues in 2012[32]

($ thousands)

	2011 Approved	Increase (Decrease)	2012 Forecast	Increase (Decrease)	2013 Forecast
Cost of Gas	107,311	(26,964)	80,347	2,065	82,412
Royalty Revenues	(40,091)	40,091	-	-	-
Royalty Adjusted Cost of Gas	67,220	13,127	80,347	2,065	82,412
GCVA Amortization	-	(8,124)	(8,124)	8,124	-
Cost of Gas Revenue Requirement	67,220	5,003	72,223	10,189	82,412

3.3.2.3 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects the five key business drivers identified in Section 5.3. Forecast 2012 and 2013 revenue requirements changes associated with these O&M expenses are summarized in the figure below by these drivers, plus the impacts of HST in 2012. As shown in Figure 3.3-7, the impact of changes in the O&M is an increase to the revenue requirements of $2.9 million in 2012 and $0.1 million in 2013, net of capitalized overhead.

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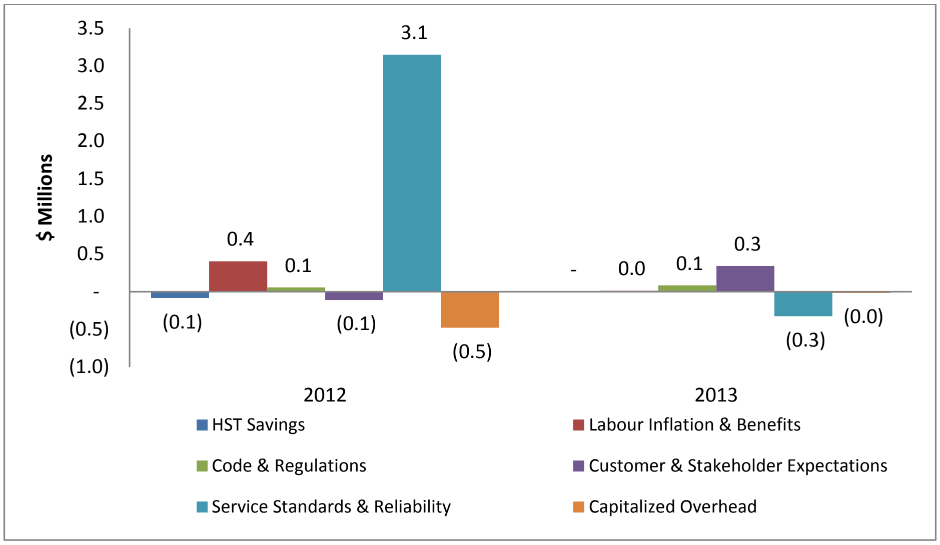
[32] Section 7.2, Schedules 4-6 and Schedule 13

Figure 3.3-7: O&M Funding Results in Increased Revenue Requirements[33]



The items in the chart above are discussed more fully in Section 5.3, and have been reflected in the calculation of the Company's revenue requirement.

3.3.2.4 Transportation Costs

Vancouver Island transportation expenses are related to the Wheeling agreement between FEVI and FEI, the capacity right agreement between FEVI and BC Hydro, and motor fuel tax and social services tax on compressor and station fuel. A revenue requirement decrease of approximately $184 thousand is forecast in 2012 with a further minor increase of $10 thousand in 2013, as shown in the table below.

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Table 3.3-7: Transportation Cost Forecast for 2012 and 2013[34]

($ thousands) Transportation Costs	Approved 2011	Forecast 2012	Forecast 2013
FEI Wheeling Agreement	3,455	3,456	3,464
BC Hydro Capacity Right	375	244	244
Taxes on Compressor and Station Fuel	292	238	240
Total Transportation Expenses	4,122	3,938	3,948

33 Please refer to Section 5.3, Table 5.3-8 and Table 5.3-9
34 Section 7.2, Schedules 4 to 6

FEVI holds a Peaking Agreement with BC Hydro dated September 19, 2007 that provides FEVI limited access to a portion of BC Hydro's firm capacity under the Transportation Services Agreement during each winter period (November 1 to March 31). FEVI pays a Capacity Right Payment each month to BC Hydro whether or not it exercises its Capacity Right. The payment is comprised of a demand toll credit for the right to use peaking capacity and a carrying charge credit to BC Hydro to offset the carrying cost of the distillate required for fuel switching. For purposes of this submission, the forecast annual cost related to this capacity right is $244 thousand for 2012 and 2013.

3.3.2.5 Depreciation and Amortization Expense

As discussed in Section 5.4, an update to the depreciation study has resulted in a reduction to Vancouver Island depreciation expense of $0.3 million. Additions in 2012 and 2013 have resulted in higher depreciation expense of $3.9 million in 2012 and a further $1.2 million in 2013. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of all depreciation changes is an increase of $4.8 million in 2012 and a further $1.6 million in 2013.

The removal cost provision has increased $3.6 million in 2012 and a further $0.1 million in 2013. Similar to depreciation expense, the removal cost provision is not deductible for income tax purposes; therefore, the total revenue requirement impact of the removal cost is $4.8 million in 2012 and a further $0.1 million in 2013.

In addition, excluding the GCVA, amortization expense has increased $2.0 million in 2012 and a further increase of $0.3 million in 2013. Both of these amounts are after-tax, so the impact to revenue requirements is as stated. In addition to the end of the amortization of the 2009 revenue surplus on December 31, 2011 which results in an increase of $1.5 million to amortization expense, several other accounts contribute to the remaining increase of $0.5 million in 2012. Table 3.3-8 reflects accounts that have a significant impact on 2012 amortization expense. The increase of $0.3 million in 2013 is primarily attributable to an increase in amortization expense of the EEC deferral account.

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Table 3.3-8: Full Amortization of 2009 Revenue Surplus Increase Amortization Expense in 2012[35]

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Amortization Expense ($ millions)		2012
Deferred Removal Costs		0.2
Gains and Losses on Asset Disposition		0.1
2010-2011 Customer Service O&M		0.3
		0.6
2009 Revenue Surplus (fully amortized)		1.5
Increase to Amortization Expense	$	2.1

The total impact on revenue requirement of changes in depreciation and amortization is an increase of $11.6 million in 2012 and $2.1 million in 2013

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3.3.2.6 Other Revenues

As discussed in Section 5.5, a significant increase in Other Revenue of $8.9 million in 2012 is forecast with no further change forecast in 2013. Increases in other revenue decrease the revenue requirement and offset the revenue deficiency. The increase in other revenue is attributable to a full year of LNG mitigation revenues from the Mount Hayes LNG facility in 2012 as compared to nine months of LNG mitigation revenues included in the approved 2011 revenue requirement as well as the LNG costs recovered from Commodity of approximately $6 million.

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3.3.2.7 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increases of $0.3 million and a further $0.4 million in 2013 both serve to increase revenue requirements. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $2.2 million and an increase in 2013 of $3.2 million. As shown in Table 3.3-9, the increase in CCA deductions, along with the amortization expense are the key contributors to the decrease in tax expense in 2012. The increase in CCA is primarily attributable to the CCE Project and amortization expense is primarily attributable to the GCVA. Tax expense associated with the earned return has increased in 2012 because of the growth in rate base due to the Mount Hayes LNG Facility and the CCE Project as well as the impact of the expiration of the VINGPA earnings reduction. Changes in amortization and earned return are the key contributors to the tax expense increase in 2013.

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[35] Section 7.2, Schedules 66 to 71

Table 3.3-9: Components of 2012 and 2013 Tax Expense Changes[36]

($ millions)	2012	2013	Total
Reduction in Tax Rate	$ (0.3)	$ (0.3)	$ (0.6)
Increase in CCA Deductions	(1.1)	(0.2)	(1.3)
Removal Cost Deduction	(0.1)	-	(0.1)
Pension and OPEB	(0.5)	0.1	(0.4)
Changes in Amortization Expense	(2.8)	3.0	0.2
Changes in Earned Return	3.1	0.4	3.5
Other	(0.6)	0.2	(0.4)
	$ (2.3)	$ 3.2	$ 0.9

3.3.2.8 Earned Return – Return on Rate Base and Financing Costs

Vancouver Island earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 4.0 per cent of that change. The rate base proposals contained in Section 6, Rate Base contribute $2.4 million to the 2012 revenue requirement and a further $1.1 million to the 2013 revenue requirement.

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The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Section 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, result in $1.3 million of additional financing costs in 2012 and $0.4 million of additional financing costs in 2013. Changes in interest rates mitigate this impact in 2012 by $2.2 and then increase by $1.8 million in 2013, resulting in a net decrease associated with financing costs of $0.9 million in 2012 followed by an increase of $2.2 million in 2013.

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Furthermore, the return on equity reduction associated with the VINGPA adjustment comes to an end on December 31, 2011 and results in an increase to revenue requirement of $1.9 million in 2012.[37]

Although a revenue deficiency of $17.6 million in 2013 is forecast, Vancouver Island is seeking approval for the continuation of existing rates for 2012 and 2013. This is because the forecast

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[36] Section 7.2, Schedules 33 to 35

[37] OIC 1510 Special Direction:
3.1 (b) Adjustment to Cost of Service
For each year from January 1, 1996, to December 31, 2011, the return on the equity component of PCEC's rate base that would have been otherwise approved by the BCUC shall be reduced by the amount of $1,867,000. Such reduction shall not be recovered in whole or in part, directly or indirectly, through rates or tolls in any manner whatsoever.

revenue deficiency described will be offset by part of the projected December 31, 2012 surplus balance of $71.4 million (before tax) in the RSDA. Section 3.4.2 provides a discussion on the RSDA and the 2012 and 2013 Vancouver Island rate proposals.

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3.3.3 SUMMARY OF WHISTLER REVENUE REQUIREMENTS

The total revenue requirements of $11.6 million in 2012 and $12.0 million in 2013 have been calculated appropriately and reflect the reasonable costs required for FEW to continue to meet the needs of our customers in the Whistler area. The following sub-sections will discuss the total Whistler revenue requirement and revenue deficiencies for 2012 and for 2013.

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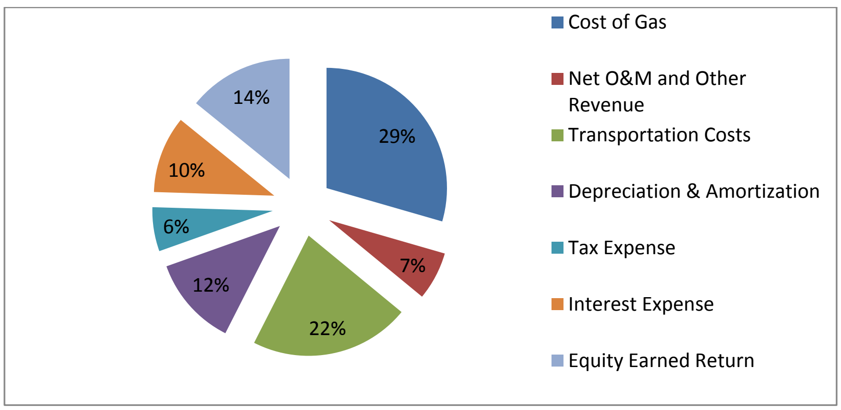
Figure 3.3-8 provides a breakdown of the components of the Whistler total revenue requirement averaged for the two year period.

Figure 3.3-8: Average Composition of the 2012 and 2013 Whistler Revenue Requirement[38]



Changes to the Whistler revenue requirements result in revenue deficiencies of $387 thousand in 2012 and $496 thousand in 2013. These deficiencies are summarized in Figure 3.3-9 below.

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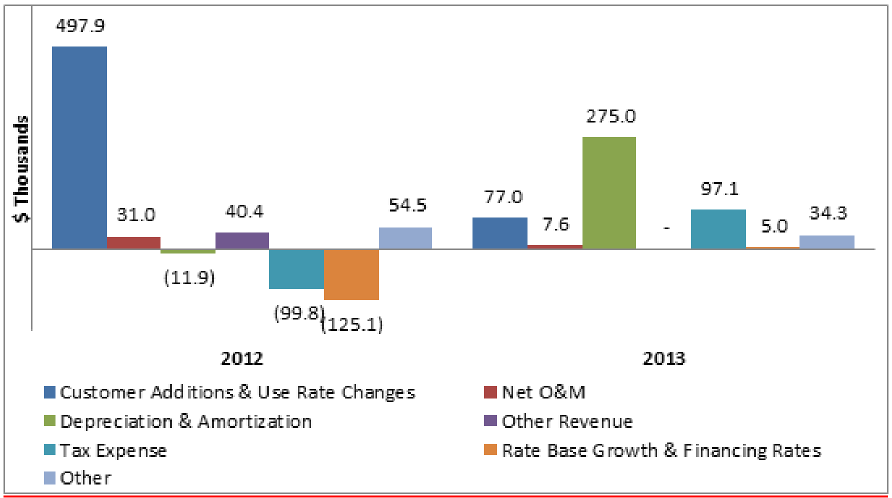
[38] Section 7.3, Schedules 5 and 6

Figure 3.3-9: Whistler Revenue Deficiency Components[39]



3.3.3.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4 is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 48 TJs lower than the demand forecast embedded in 2011 rates, with a further decrease of approximately 7 TJs in 2013.[40] This decrease in demand is attributable to the projection for the use rate on an ongoing basis being lower than originally anticipated, as Whistler customers have consumed less natural gas than they had historically consumed propane. This trend has not been offset by customer growth. This decrease in demand results in a significant revenue deficiency of approximately $498 thousand in 2012 and $77 thousand in 2013.

The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and have been properly reflected in the calculation of the Company's revenue requirement.

3.3.3.2 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects four of the key business drivers identified in Section 5.3. 2012 and 2013 revenue requirements are summarized in the figure below by these drivers, plus the impacts of HST in 2012. As shown in Figure 3.3-10, the impact of changes in the O&M

[39] Section 7.3, Schedule 1
[40] Section 7.3, Schedules 4 to 9

is an increase to the revenue requirement of $31 thousand in 2012 and $8 thousand in 2013, net of capitalized overhead.

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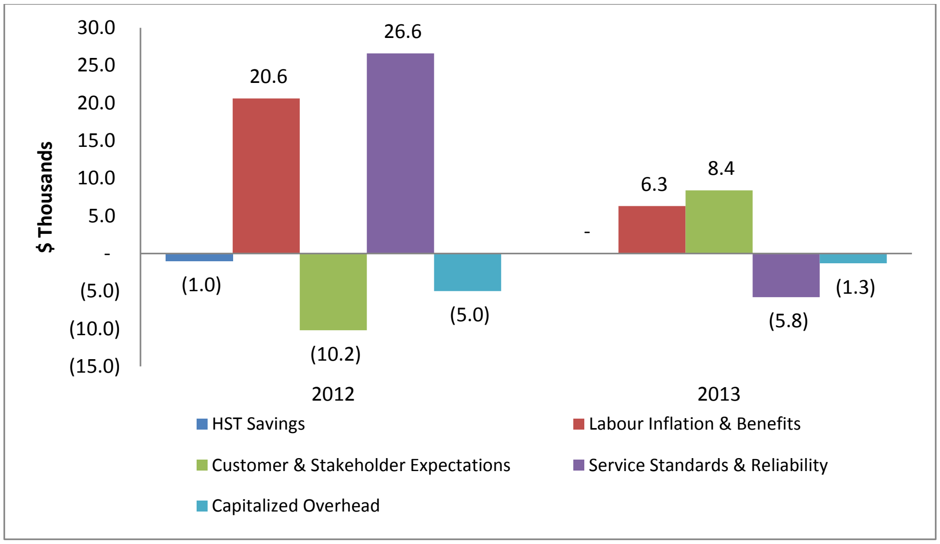
Figure 3.3-10: O&M Funding Results in Increased Revenue Requirements[41]



The items in the chart above are discussed more fully in Section 5.3, and have been reflected in the calculation of the Company's revenue requirement.

3.3.3.3 Transportation Costs

Whistler transportation costs reflect the charge paid by Whistler to Vancouver Island for gas transportation service on the Whistler Pipeline. The transportation costs are forecast at approximately $2.6 million per year for 2012 and 2013, increasing the revenue requirement by $60 thousand in 2012 and $35 thousand in 2013.[42]

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3.3.3.4 Depreciation and Amortization Expense

As discussed in Section 5.4, an update to the depreciation study has resulted in an increase to Whistler depreciation expense of $30 thousand. Additions in 2012 and 2013 have resulted in higher depreciation expense of $3 thousand in 2012 and a further $16 thousand in 2013. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement

[41] Please refer to Section 5.3, Table 5.3-10 and Table 5.3-11
[42] Section 7.3, Schedules 4 to 6

impact of all depreciation changes is an increase of $44 thousand in 2012 and a further $21 thousand in 2013.

The removal cost provision has increased $75 thousand in 2012 and a further $2 thousand in 2013. Similar to depreciation expense, the removal cost provision is not deductible for income tax purposes; therefore, the total revenue requirement impact of the removal cost is $100 thousand in 2012 and a further $3 thousand in 2013.

In addition, amortization expense has decreased $156 thousand in 2012 and increased $251 thousand in 2013. Both of these amounts are after-tax, so the impact to revenue requirements is as stated. The decrease in 2012 and corresponding increase is 2013, is largely attributable to the one year amortization of the credit balance in the Pipeline Cost Variance Account of $434 thousand. Please refer to Section 6.3 for a discussion of each of the deferral accounts.

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3.3.3.5 Other Revenues

As discussed in Section 5.5, a decrease in Other Revenue of $40 thousand in 2012 is forecast with no further change forecast in 2013. Decreases in other revenue increase the revenue requirement and the revenue deficiency. The decrease is attributable to a forecast reduction in Late Payment Charges; a downward trend consistent with the lower bad debt expense experienced by the Utilities.

3.3.3.6 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax reduction of $42 thousand in 2012 results in a decrease to the revenue requirement and is increased by $8 thousand in 2013. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $57 thousand and an increase in 2013 of $89 thousand.

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3.3.3.7 Earned Return

Whistler earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 4.0 per cent of that change. The rate base proposals contained in Section 6, contribute an $22 thousand reduction to the 2012 revenue requirement and a further reduction of $28 thousand to the 2013 revenue requirement as costs associated with the Whistler natural gas conversion continue to amortize.

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The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, and changes in interest rates result in a net decrease associated with financing costs of $103 thousand in 2012 followed by an increase of $33 thousand in 2013.

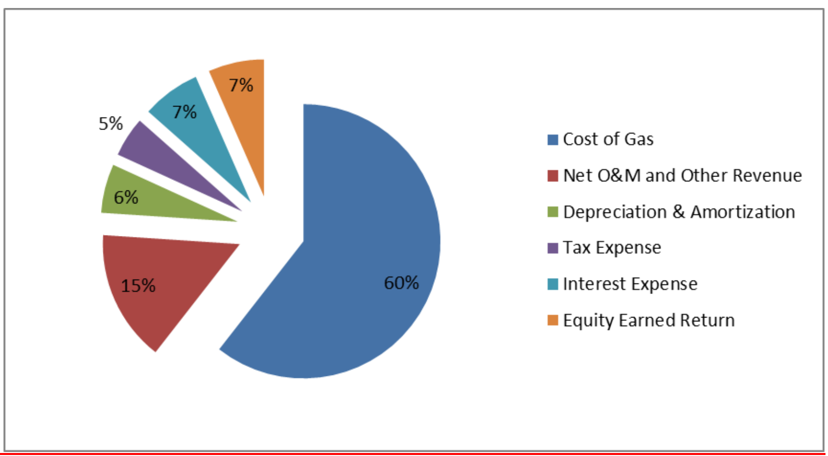
The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing delivery rates.

3.3.4 SUMMARY OF FORT NELSON REVENUE REQUIREMENTS

The total revenue requirements of $4.6 million in 2012 and $5.0 million in 2013 have been calculated appropriately and reflect the reasonable costs required for Fort Nelson to continue to meet the needs of our customers. The following sub-sections will discuss the total Fort Nelson revenue requirement and revenue deficiencies for 2012 and for 2013.

Figure 3.3-11 provides a breakdown of the components of the Fort Nelson total revenue requirement averaged for the two year period.

Figure 3.2-11: Average Composition of the 2012 and 2013 Fort Nelson Revenue Requirement[43]



Changes to the Fort Nelson revenue requirements result in a revenue surplus of $125 thousand in 2012 and a deficiency of $283 thousand in 2013, as summarized in Figure 3.3-12 below.

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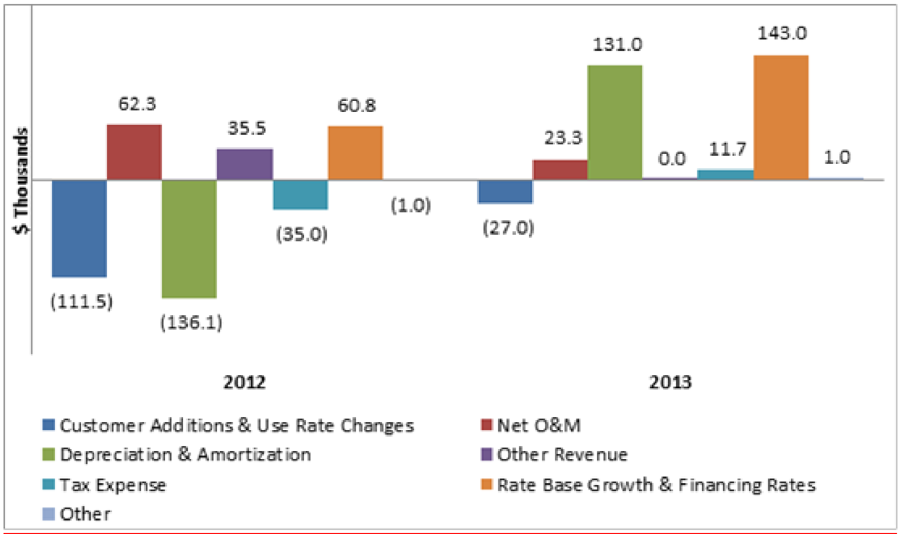
[43] Section 7.4, Schedules 5 and 6

Figure 3.3-12: Fort Nelson Revenue Deficiency Components[44]



3.3.4.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4, is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 34 TJs greater than the demand forecast embedded in 2011 rates, with an increase of approximately 9 TJs in 2013. This increase in demand is attributable to customer growth and changes in use rates and results in a revenue surplus of approximately $112 thousand in 2012 and $27 thousand in 2013.[45]

The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and has been properly reflected in the calculation of the Company's revenue requirement.

3.3.4.2 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects the two key business drivers identified in Section 5.3. 2012 and 2013 revenue requirements are summarized in the figure below by these drivers. As shown in Figure 3.3-13, the impact of changes in the O&M is an increase to the revenue requirement of $62 thousand in 2012 and $23 thousand in 2013, net of capitalized overhead.

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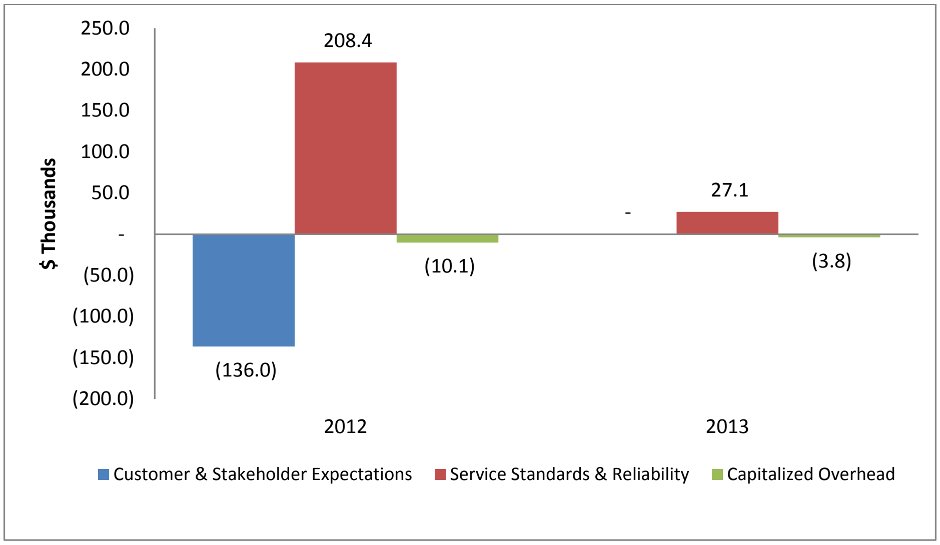
44 Section 7.4, Schedule 1
45 Section 7.4, Schedules 4 to 9

Figure 3.3-13: O&M Funding Results in Increased Revenue Requirements[46]



The items in the chart above are discussed more fully in Section 5.3, and have been properly reflected in the calculation of the Company's revenue requirement.

3.3.4.3 Depreciation and Amortization Expense

A full year of depreciation associated with the Muskwa River Crossing Project in 2013, as well as additions in 2012 and 2013, have resulted in higher depreciation expense of $47 thousand in 2012 and a further $33 thousand in 2013. This increase is offset by the impacts of the changes in depreciation rates which reduce the expense by $30 thousand in 2012. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of depreciation changes is an increase of $22 thousand in 2012 and a further $44 thousand in 2013.

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In addition, amortization expense has decreased $158 thousand in 2012 and increased 87 thousand in 2013. This amount is after-tax, so the impact to revenue requirements is as stated. The decrease in 2012 and corresponding increase is 2013, is largely attributable to the Muskwa River Crossing 2011 deferral account. This deferral account refunds to customers the 2011 cost of service associated with the Muskwa River Crossing Project that was recovered from customers through 2011 delivery rates. This deferral account can be found on Tab 7.4, Schedule 68, Line 18.

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46 Please refer to Section 5.3, Table 5.3-12 and Table 5.3-13

3.3.4.4 Other Revenues

As discussed in Section 5.5, a decrease in Other Revenue of $36 thousand in 2012 is forecast with no further change forecast in 2013. Decreases in other revenue increase the revenue requirement and the revenue deficiency. The decrease is attributable to a forecast reduction in Late Payment Charges; a downward trend consistent with the lower bad debt expense experienced by the Utilities.

3.3.4.5 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increase of $7 thousand in 2012 and a further increase of $6 thousand in 2013 result in increases to the revenue requirement. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $42 thousand and an increase in 2013 of $6 thousand.

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3.3.4.6 Earned Return

Fort Nelson earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.8 per cent of that change. The rate base proposals contained in Section 6 increase revenue requirement by $23 thousand in 2012 and have a further increase of $70 thousand to the 2013 revenue requirement.

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The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, and changes in interest rates result in a net increase associated with financing costs of $38 thousand in 2012 followed by an increase of $73 thousand in 2013.

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The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing delivery rates.

3.3.5 SUMMARY OF AMALGAMATED COST OF SERVICE

As discussed in Section 1.2.5, in addition to seeking approval of rates for each of the FEU, we are also seeking approval of the amalgamated cost of service for 2013. This will form the first step of the Companies' plans to amalgamate, and will be followed by an application in Fall 2011 requesting approval to amalgamate with a rate design based on the amalgamated cost of service. As the FEU are seeking approval for the amalgamated cost of service prior to the merits of amalgamation being considered by the Commission, the FEU have phrased the approval requested in this application to be conditional upon the amalgamation being approved and going forward. The efficiency rationale for proceeding in this fashion is also discussed in Section 1.2.5.

In Section 3.3.5.1, the FEU provide a summary of the amalgamated cost of service. The amalgamated cost of service represents the summation of the Mainland, Vancouver Island, Whistler and Fort Nelson cost of service as described above, as well as adjustments to account for cost of service line items that will eliminate or change upon amalgamation.

3.3.5.1 FEU Amalgamated Cost of Service

The FEU amalgamated cost of service of $1.509 billion ($779.9 million delivery margin) is determined in Section 7.5, Schedule 2, as follows:

Table 3.3-10: Amalgamated 2013 Cost of Service

($ thousands)	Reference	2013 Total	2013 Cost of Gas	2013 Cost of Service[1]
Mainland	*Section 7, Tab 7.1, Schedule 6, Column 5*	$ 1,282,763	$ 658,568	$ 624,195
Vancouver Island	*Section 7, Tab 7.2, Schedule 6, Column 5*	214,087	76,399	137,688
Whistler	*Section 7, Tab 7.3, Schedule 6, Column 5*	12,173	3,455	8,718
Fort Nelson	*Section 7, Tab 7.4, Schedule 6, Column 5*	5,001	2,945	2,056
		1,514,024	741,367	772,657
Add (Deduct):				
FEI (LNG Mitigation fee to FEVI)		-	(12,024)	12,024
Other Cost of Service & Rate Base		(2,158)	-	(2,158)
FEW Transportation Charge		(2,585)	-	(2,585)
Squamish Transportation Charge		(416)	(416)	-
Total Amalgamation Adjustments		(5,159)	(12,440)	7,281
Amalgamated FEU Cost of Service		**$ 1,508,865**	**$ 728,927**	**$ 779,938**

[1] *Cost of service excluding cost of gas*

Note: Table 3.3-10 has not been updated to reflect September 12th Evidentiary Update. Financial schedules pertaining to the amalgamated cost of service will be provided in the Phase "A" Rate Design Application

AMALGAMATION ADJUSTMENTS

The cost of service must be adjusted to reflect intercompany items that will be eliminated upon amalgamation and rate harmonization. In the case of shared services and wheeling or transportation charges between the Regions, the amalgamation of the entities results in the inter-company agreements ceasing to be in effect, and the need to retain them for regulatory purposes disappears upon amalgamation. In the case of the three items below, an adjustment must be made to the cost of service.

- The LNG mitigation revenues are included in the Vancouver Island delivery cost of service with the offset cost residing in the Mainland midstream costs. For purposes of this analysis, FEU has taken the approach of showing this $12 million adjustment to the delivery cost of service and cost of gas; however, the allocation of the LNG mitigation revenues as between midstream and delivery will be reviewed in the Fall 2011 Amalgamation and Rate Design Phase 'A' Application and may result in changes from what has been presented in this RRA.

- Other cost of service impacts from changes in interest expense and cash working capital occur. The short term interest expense for the amalgamated cost of service is determined using the FEI short term debt rate, which results in a reduction to the cost of service of approximately $1.9 million. The cash working capital for the amalgamated cost of service is determined using the FEI approved Lead and Lag days.

- The FEW Transport charges are accounted for as a cost in FEW but as a revenue FEVI; therefore the delivery cost of service has been adjusted to remove these costs.

- The Squamish Transport charges are accounted for as commodity costs in FEI but as revenue in FEVI; therefore the cost of gas has been adjusted to remove these costs.

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The Companies do not expect that there will be material cost savings as a result of the amalgamation, since the operations and management of the utilities are already fully integrated and the savings have been captured for the benefit of customers over the 2004 through 2011 period; however, some small annual savings will be realized. These savings would be limited to reporting efficiencies such as financial, legal and regulatory reporting and debt issuance requirements. There will also be costs incurred to effect a future legal amalgamation of the Companies, if approved. For the one year of amalgamated cost of service (2013) relevant to this RRA, the costs and savings are expected to offset each other, and therefore the FEU have not forecast a change to the cost of service for this item. The FEU will capture any variances from the forecast of zero in a deferral account for future recovery from/return to customers. Although the costs related to the legal amalgamation are one-time in nature, any efficiency savings, although not large, will be ongoing, and will be included in future RRAs.

3.4 Rate Proposals

3.4.1 DELIVERY RATES

The proposed delivery rates reflect the revenue requirements for each Utility as discussed in Section 3.3. Preliminary bill impacts and tariff continuity schedules for all customers are provided in Appendix F-2, showing the annual bill impacts below. The following summary for each Utility provides the delivery rate change required and a summary of the annual bill impact of the rate proposals for an average residential customer in Mainland, Whistler, and Fort Nelson.

3.4.1.1 Mainland

The Mainland proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 5.6 per cent in 2012 and an additional effective base rate delivery increase of 6.3 per cent in 2013 (cumulative increase of 11.9 per cent).[47] These proposed increases along with changes to the RSAM and ESM rate riders for 2012 result in changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 3.0 per cent or $30 in 2012 and an additional 3.2 per cent or $30 in 2013.[48]

3.4.1.2 Whistler

The Whistler proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 5.0 per cent in 2012 and an additional effective base rate delivery increase of 6.5 per cent in 2013 (cumulative increase of 11.6 per cent).[49] These proposed increases along with changes to the RSAM rate rider for 2012 result in changes to the annual bill of an average Whistler residential customer with an approximate net increase of 6.5 per cent or $96 in 2012 and an additional 4.3 per cent or $64 in 2013.[50]

3.4.1.3 Fort Nelson

The Fort Nelson proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate decrease of 6.7 per cent in 2012 and an additional effective base rate delivery increase of 15.0 per cent in 2013 (cumulative increase of 8.3 per cent).[51] These proposed increases along with changes to the RSAM rate rider for 2012 result in changes to the annual bill of an average Fort Nelson residential customer with an approximate net decrease of 3.2 per cent or $32 in 2012 and an increase of 6.0 per cent or $60 in 2013.[52]

3.4.2 VANCOUVER ISLAND EFFECTIVE RATES

FEVI has been operating under the Vancouver Island Natural Gas Pipeline Act Special Direction[53] (the "Special Direction") since 1995.[54] The Special Direction is appended to the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA"), an agreement among the predecessor companies to FEVI, the Province, and (by assignment from Westcoast Energy Inc.) Fortis BC Holdings Inc. ("FHI"). The VINGPA contemplates the payment by the Provincial

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47 Section 7.1, Schedules 2 and 3
48 Appendix F-2, Tab 1.1.1 and Tab 1.2.1, Page 1
49 Section 7.3, Schedules 2 and 3
50 Appendix F-2, Tab 3.1 and Tab 3.2, Page 1
51 Section 7.4, Schedules 2 and 3
52 Appendix F-2, Tab 4.1.1 and Tab 4.2.1, Page 1
53 OIC No. 1510 (Dec. 13, 1995).
54 The Special Direction states that it shall cease to have any application after the latest of three conditions occurring: (a) the time when the balance of the RDDA has been reduced to zero; (b) the expiration/termination of the Joint Venture Transportation Service Agreement ("JV TSA"), but no later than January 1, 2011; or (c) the date of the termination of the Squamish Gas TSA. Although the RDDA has been reduced to zero and January 1, 2011 has passed, the Squamish Gas TSA continues to remain in effect thus keeping the Special Direction in effect.

Government of gas royalty revenues to FEVI through 2011, which are based on the wellhead price of gas until December 31, 2011, and have mitigated fluctuations in the cost of gas to the benefit of FEVI's Core Market customers. The Special Direction and the VINGPA contemplate the creation of the RDDA. The RDDA held Annual Revenue Deficiencies through 2002, and thereafter the Commission was directed by the Special Direction to set rates so as to permit the recovery of the Accumulated Revenue Deficiency in the RDDA over the shortest period reasonably possible, having regard to the competitive position of FEVI's rates relative to alternative energy sources and the desirability of reasonable rates for customers. The Core Market rates set by the Commission for FEVI under the Special Direction from 2003 to 2009 were based on the "Soft-Cap" mechanism and tied to electricity and fuel oil rates as competitive alternatives, appropriately recognizing the difficult competitive environment faced by FEVI. Although Core Market customer rates increased over time, the Soft-Cap ensured relative rate stability compared to competitive alternatives and volatile natural gas prices.

The 2010/11 RRA and RDA was FEVI's first rate application following the repayment of the RDDA. In that application, Vancouver Island developed and received approval for an interim rate mitigation strategy to offset the rate pressure resulting from the loss of the gas royalty revenues on December 31, 2011. This interim strategy resulted in a rate freeze for sales customers and the creation of a RSDA, to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. As demonstrated in Table 3.4-1, this was a successful strategy resulting in a projected after tax balance of $51.7 million at the end of 2011 to be used for future rate mitigation.

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In this Application, Vancouver Island is seeking approval for a continuation of the existing rates for sales customers, Whistler and BC Hydro. The rates for VIJV and Squamish will remain in accordance with their respective Transportation Service Agreements. As discussed in Section 1.2.5, FEVI believes that a rate freeze is an appropriate rate mitigation strategy for the 2012 and 2013 forecast period in light of the continued long term significant upward pressure on rates for Vancouver Island customers, and continued pressure to remain competitive with other energy sources. FEU's plans to amalgamate via the forthcoming Amalgamation and Phase 'A' Rate Design Application in Fall 2011 which, if approved, will provide the long-term risk mitigation strategy for FEVI customers. A rate freeze for the next two year period will enable continued rate certainty for FEVI customer's until the longer term solution is in place. In the event that amalgamation is not approved, a two year rate freeze will enable natural gas on Vancouver Island to remain competitive with other energy sources for an additional 1-2 year period.

To achieve this rate freeze, the RSDA mechanism must remain in place for 2012 and 2013; FEVI is seeking approval for the continuation of the RSDA. The RSDA will continue to capture the differences in 2012 and 2013 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. The existing surplus balance in the RSDA will be used to partly offset the forecast revenue deficiency in 2013 and results in forecast closing RSDA balances of $53.5 million, after tax in 2012 and $42.3 million, after tax in 2013.

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Table 3.4-1: The RSDA Mitigates Rate Impacts Today and in the Future,

($ Thousands)	Actual 2010	Projected 2011	Forecast 2012	Forecast 2013
Opening RSDA Balance, net of tax	(3,300)	(35,618)	(51,677)	(53,513)
Annual (Surplus)/ Deficiency	(44,743)	(20,661)	(409)	17,173
Add: Interest on Balance	(457)	(1,188)	(2,038)	(2,234)
Less: Tax	12,882	5,790	612	(3,735)
Closing RSDA Balance, net of tax	**(35,618)**	**(51,677)**	**(53,513)**	**(42,308)**
Tax Rate	28.5%	26.5%	25.0%	25.0%
Closing RSDA Balance, before tax	**(49,816)**	**(70,309)**	**(71,350)**	**(56,411)**

As discussed in Section 1.2.5, using the existing low cost of gas as the base case, the future rate impacts expected for Vancouver Island are still in the range of a 20 percent increase over the next several years. This impact will be magnified, and may be doubled, should increases in the cost of gas occur. Therefore, FEVI believes that it is appropriate to maintain a rate freeze for 2012 and 2013 and preserve the RSDA mechanism to mitigate future rate increases for our customers.

3.4.3 DELIVERY RATE RIDERS

3.4.3.1 Mainland

The Mainland RSAM Rider reflects a projected balance of $8.4 million owing to customers at December 31, 2011. As noted in Section 6.3.1.3, RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a credit rider of $0.032/GJ in 2012 applicable to Rate Schedules 1, 1B, 1U, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23; the 2013 Rider will be set as part of FEI's Fourth Quarter 2011 Gas Cost report.[55] The change in the RSAM rider results in a decrease to the annual bill of an average Lower Mainland residential customer of 0.1 percent or $1 in 2012.[56]

As shown in Appendix F-2, the expiry of the Mainland Earnings Sharing Mechanism credit rider will result in a nominal increase to the annual bills of Mainland non-bypass customers. The expiry of this riders results in changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 0.5 per cent or $5 in 2012.[57]

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55 Section 7.1, Schedule 85
56 Appendix F-2, Tab 1.1.1, Page 1
57 Ibid

3.4.3.2 Whistler

The Whistler RSAM Rider reflects a projected balance of $0.8 million recoverable from customers at December 31, 2011. As noted in Section 6.3.1.3, RSAM account balances are requested to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a debit rider of $0.524/GJ in 2012 applicable to all Whistler customers; the 2013 Rider will be set as part of FEW's Fourth Quarter 2011 Gas Cost report.[58] The impact of the RSAM rider is significant and results in an increase to the annual bill of an average Residential Whistler customer of 3.2 per cent or $47 in 2012.[59]

3.4.3.3 Fort Nelson

The Fort Nelson RSAM Rider reflects a projected balance of $16.0 thousand owing to customers at December 31, 2011. As noted in Section 6.3.1.3, RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a credit rider of $0.011/GJ in 2012 applicable to Rate Schedules 1, 2.1, 2.2 and 25; the 2013 Rider will be set as part of Fort Nelson's Fourth Quarter 2011 Gas Cost report.[60] The impact of the RSAM rider results in a decrease to the annual bill of a Residential Fort Nelson customer of 0.6 per cent or $6 in 2012.[61]

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[58] Section 7.3, Schedule 85
[59] Appendix F-2, Tab 3.1, Page 1
[60] Section 7.4, Schedule 85
[61] Appendix F-2, Tab 4.1.1, Page 1

For Vancouver Island, rising UPC in almost all Commercial Rate Schedules has helped offset the declining demand in the Residential Rate Schedule that is forecast to occur as a result of the continuing declining UPC. Following the recent volatility in both the housing market and UPC, Vancouver Island observed some returning stability in 2010. However in 2011, the industrial rate class, based on transportation contract demand, is projected to increase by 15 percent compared to 2010 actual resulting in an overall increase of 9 percent for Vancouver Island compared to 2010. For 2012 and 2013, total demand remains relativity flat for FEVI as a whole.

For Whistler, declining use per customer in the Commercial Large General Service Rate Schedules ("LGS-2" and "LGS-3") combined with reduced customer additions offset increases seen in the other commercial and residential Rate Schedules, resulting in overall reduced demand.

For Fort Nelson, an increasing UPC in commercial Rate Schedule 2.2 drove the increase in demand for this region.

As shown in the following Table 4.2-2, net customer additions for all Companies are expected to drop slightly in 2011 compared to 2010. For 2012 and 2013, net additions are forecast to rebound to and then exceed 2010 levels. Forecast additions are up significantly from the 8,144 customers added in 2009 but fall short of the 12,775 customers added in 2008.

Table 4.2-2: The Companies – Forecast Customer Additions

	2010 Actual	2011 Forecast	2012 Forecast	2013 Forecast
Mainland	6,928	6,314	6,656	6,923
Vancouver Island	2,432	2,422	2,557	2,658
Whistler	12	18	19	19
Fort Nelson	21	23	22	24
All Companies	**9,393**	**8,777**	**9,254**	**9,624**

The following Table 4.2-3 describes the existing Rate Schedules included in each of the three rate groups (Residential, Commercial, Industrial) for the four regions[63] discussed in this section.

[63] Note: The Mainland region presented in this section includes the Lower Mainland, Inland, Columbia and Revelstoke regions.

5 COST OF SERVICE

5.1 Introduction to Cost of Service

FEU's revenue requirements are composed of the changes in revenue at existing rates (Section 4) and the cost of service.

Of these two components, changes in the cost of service have the biggest impact on the revenue requirement. Section 5 describes all of the components of the cost of service, and the changes in the forecast components for 2012 and 2013.

The cost of service is composed of:

1. Cost of gas (Section 5.2)
2. Operations and maintenance expenses (Section 5.3)
3. Depreciation and amortization expense (Section 5.4)
4. Other revenue (Section 5.5)
5. Taxes (Section 5.6)
6. Financing Costs and ROE (Section 5.7)

In turn, the depreciation and amortization and financing costs and ROE sections are dependent on the rate base forecasts included in Section 6.

Each of the following sections describes how the components have been calculated. The forecasts included in the following sections appropriately reflect the reasonable costs required for FEU to continue to meet the needs of our customers and the communities in which we serve.

5.2 Cost of Gas

5.2.1 INTRODUCTION TO COST OF GAS

This section of the Application describes the cost of gas, where the term "gas" refers to natural gas, propane, and biomethane, for the FEU. Biomethane makes up a very small component of the FEU gas supply portfolio and the biomethane costs are discussed in Appendix J. The total cost of gas is forecast to be approximately $746.1 million in 2012 and $747.4 million in 2013. Effectively managing these costs is essential to providing reliable and cost effective service to customers.

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Table 5.2-1: Cost of Gas Forecasts[70]

($ thousands)

Utility/Region	Forecast 2012	Forecast 2013
Mainland	$ 659,338	$ 658,568
Vancouver Island	80,347	82,412
Whistler	3,493	3,455
Fort Nelson	2,900	2,945
Total	**$ 746,078**	**$ 747,380**

5.2.2 MANAGING GAS COSTS TO ENSURE RELIABLE, COST EFFECTIVE SUPPLY

The total cost of gas is comprised of the forecast natural gas and propane commodity costs, and the forecast costs for midstream components (storage and transportation). The gas costs for Mainland, Whistler, Fort Nelson, and Revelstoke sales rate customers are reviewed and approved in separate applications by the Commission and FEI (including Fort Nelson and Revelstoke) and FEW are not requesting approval of those forecast gas costs as part of this Application. These forecast gas costs are, however, required to determine a number of revenue requirement line items that form part of this Application.

Unlike FEI and FEW, FEVI is requesting approval of its forecast cost of gas, as described in Section 5.2.3.2, in order to determine the approved cost of gas, as variances between the approved and incurred cost of gas are recorded in the Gas Cost Variance Account, which is further described in Section 6.3. The FEVI forecast gas costs are also required to determine a number of revenue requirement line items that form part of this Application.

5.2.2.1 Gas Supply Management

Gas Supply is the area within the Energy Supply and Resource Planning department that manages the Companies' natural gas and propane supply functions. The department ensures that there are reliable, secure and cost effective supplies of natural gas and propane for Mainland, Vancouver Island, Whistler, Fort Nelson, and Revelstoke customers. The gas supply function encompasses most elements of the merchant role, providing supply to firm and interruptible customers. The cost to complete these management activities is included in Core Market Administration Expense ("CMAE") and forms part of the cost of gas. CMAE is discussed in more detail later in this section.

The key objectives relating to the management of natural gas and propane supply include:

- providing natural gas and propane supply to customers;

70 Section 7.1 to 7.4, Schedule 13

Table 5.2-2: Vancouver Island 2011-2013 Cost of Gas Excluding Royalty Revenues and GCVA Impacts

	Amounts in $ Thousands		
	2011 Projected	**2012 Forecast**	**2013 Forecast**
Commodity	$ 38,841	$ 46,828	$ 51,919
Transportation Demand Charges	7,451	8,173	7,584
Storage Demand Charges	9,971	9,509	9,445
Hedging Cost / (Gain)	16,394	15,174	12,786
Gas Supply Management Costs	630	663	678
Total Cost of Gas	**$ 73,287**	**$ 80,347**	**$ 82,412**

With this Application, FEVI seeks approval of the 2012 and 2013 cost of gas. Variances between the actual incurred cost of gas and the approved forecast cost of gas for the two-year period of the 2012-2013 revenue requirements will be captured in the GCVA for amortization through future rates.

5.2.3.3 Fort Nelson Cost of Gas

For the 2012 and 2013 forecast period, the forecast cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The gas cost recovery charges for the sales rate customers are subject to quarterly review by the Commission, and Fort Nelson is not requesting approval of forecast gas costs with this Application. Forecast gas costs are, however, required in the determination of a number of revenue requirement line items.

The currently approved gas cost recovery charge was set with the 2011 First Quarter Gas Cost report that was filed on March 3, 2011. The gas cost recovery rates for Fort Nelson customers effective at April 1, 2011 remained unchanged from January 1, 2011 rates, as accepted by Commission Letter No. L-16-11.

5.2.3.4 Revelstoke Cost of Gas

For the 2012 and 2013 forecast period, the forecast cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The approved propane reference price, and corresponding gas cost recovery charges, for the sales rate customers are subject to quarterly review by the Commission, and Revelstoke is not requesting approval of forecast gas costs with this Application. Forecast gas costs are, however, required in the determination of a number of revenue requirement line items.

- Operations Support – manages procurement, supply chain management, meter and measurement services, and communication and instrumentation systems.
- Facilities – manages all non-gas assets including buildings, property, security, space and furniture requirements as well as centralized office services.
- Human Resources – manages the overall workforce strategy, employee services, labour relations, compensation and benefits, recruiting, and employee development.
- Finance & Regulatory Affairs – manages the financial and regulatory reporting requirements.
- Corporate – provides overall management and leadership.

The table below shows the O&M (before capitalized overheads) for the years 2010 through 2013. O&M increases in the test period are 7.6 percent for 2012 and 4.1 percent for 2013.

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Table 5.3-1: O&M Funding Reflects Our Continued Commitment to Safety and Integrity

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 206,464	$ 206,519	$ 214,680	$ 214,680	$ 230,189	$ 241,103
Vancouver Island	$ 31,229	$ 29,852	$ 32,702	$ 32,702	$ 36,117	$ 36,232
Whistler	$ 849	$ 773	$ 868	$ 868	$ 904	$ 913
Fort Nelson	$ 814	$ 794	$ 812	$ 812	$ 884	$ 911
Total	$ 239,356	$ 237,938	$ 249,063	$ 249,063	$ 268,094	$ 279,159

For 2012 and 2013, the O&M expenditure changes can be divided into five categories or cost drivers: labour inflation and benefits, codes and regulations, customer and stakeholder expectations, demographics, and a continued focus on service standards and reliability.

The following section will describe the five O&M cost drivers. Summary tables showing the incremental spending by cost driver for each of the departments for 2012 and 2013 is provided in Section 5.3.3. An overview of the changes in staffing levels is provided in Section 5.3.4. A description of changes on a department by department basis is provided in Sections 5.3.5 through 5.3.16. Capitalized overhead and corporate and shared services will also be discussed in Sections 5.3.17 and 5.3.18, respectively.

cash compensation at the median of our defined peer group. Our total compensation core guiding principle is to deliver a total compensation program that includes employee understanding, administrative ease and cost controls that drive a perceived value which exceeds program costs. Paying competitive rates will allow FEU to attract the appropriate talent and help to retain employee knowledge in key areas of the Companies that are critical to the future success of the business. FEU needs to ensure that the Total Rewards cater to a diverse population and respond to the broad needs of a diverse workforce while retaining, attracting and motivating the talented individuals that FEU needs in order to continue to meet business goals and deliver service to our customers. The compensation philosophy of the FEU is discussed in Section 3.1.3.

The forecast O&M labour inflation and benefit increases for 2012 and 2013 are shown in the following table.

Table 5.3-2: O&M Labour and Benefit Increases for 2012 and 2013[74]

($thousands) Utility/Region	2012 Labour Inflation	2012 Benefits	Total for 2012	2013 Labour Inflation	2013 Benefits	Total for 2013
Mainland*	2,160	6,256	8,416	2,507	(59)	2,448
Vancouver Island	152	252	404	140	(127)	13
Whistler	17	4	21	4	3	6
Total	**2,329**	**6,512**	**8,841**	**2,651**	**(183)**	**2,467**

* Fort Nelson - Labour Inflation and Benefits is included in Mainland and allocated to Fort Nelson

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[74] The in-sourcing of the Customer Service department results in roughly 300 incremental employees. For this new employee group, 2012 is considered to be the base year, so that no incremental labour inflation or benefits are displayed for this department in that year in this table. Labour Inflation and benefit increases for the Customer Service group in the amount of $0.6 million is included in 2013.

Unions explored options which helped to mitigate the contribution rate increases, and we will continue to explore methods to mitigate these in the future.

Valuation of the IBEW and COPE defined benefit pension plan was recently completed while valuation of the M&E defined benefit pension plan is in progress with results expected in May, 2011. Due to the 2008 financial sector crisis, competitive plan benefits, increasing liabilities and lower than anticipated plan investment returns, contribution rate increases are occurring for both the Companies and plan members. Plan contribution rates for both the Companies and plan members are as follows:

- For non-union employees, 7.5 percent of pensionable earnings effective October 1, 2010;
- For COPE and IBEW, 12.95 percent of plan earnings effective April 1, 2011.

These plan contribution rates are expected to remain in effect for a period of up to three years as the most recent actuarial valuations of the above noted plans were completed in late 2010 and early 2011. Actuarial valuations are only required to be completed every three years and the recently completed valuations are expected to be valid until late 2013.

Pension and OPEB expenses are based upon actuarial estimates provided by the Company's actuaries, Towers Watson and Morneau Sobeco. Both firms have provided actuarial services to FEU for more than ten years and are very knowledgeable about FEU's pension plans and actuarial forecasting. For regulatory purposes, pension and OPEB expense forecasts for 2012 and 2013 have been prepared using approved US GAAP accounting methodologies.

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- For the Mainland, the actuarial estimates for pension and OPEB costs, excluding pension and OPEB for the incremental employees in the Customer Service department, are $18.5 million for 2012 and $17.1 million for 2013. A pro-rata share is allocated to Fort Nelson.

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- Actuarial estimates of the pension and OPEB costs for the incremental employees in the Customer Service department are $0.4 million for 2012 and $0.4 million for 2013.
- For Vancouver Island, the actuarial estimates for pension and OPEB costs are $2.3 million for 2012 and $2.2 million for 2013 with a pro-rata share being allocated to Whistler.

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These actuarial estimates do not translate directly into O&M expenses because a portion of the pension and OPEB expenses are capitalized. Pension and OPEB expenses are apportioned into two components, a current service component and a net benefit expense which includes the current service component not capitalized. The current service component is included in labour loadings and therefore in both O&M and capital expenditures, consistent with the treatment approved in the 2010-2011 RRA. The past service cost component is included in O&M only, as these costs have already vested.

- For FEI in 2012, the pension and OPEB costs are forecast to increase $7.5 million over 2011. This consists of an increase to the current service component of $3.9 million, and an increase to the past service component of $3.6 million. After the allocation of the current service component to capital and deferrals, the net impact to O&M in 2012 is an increase of of $5.7 million. For FEI in 2013, the Pension and OPEB costs are forecast to decrease $1.4 million over 2012. This consists of an increase to the current service component of $0.4 million, offset by a reduction to the past service component of $1.8 million. After the allocation of the current service component to capital and deferrals, the net impact to O&M in 2013 is a reduction of $1.5 million.

- For FEVI in 2012, the pension and OPEB costs are forecast to increase $0.5 million over 2011. This consists of an increase to the current service component of $0.2 million, and an increase to the past service component of $0.3 million. After the allocation of the current service component to capital and deferrals, the net impact to O&M in 2012 is an increase of of $0.4 million. For FEVI in 2013, the pension and OPEB costs are forecast to decrease $0.1 million over 2012. This consists of a marginal increase to the current service component, offset by a marginal reduction to the past service component. The net impact to O&M in 2013 is a reduction of $0.1 million.

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With respect to accounting treatment, we have prepared the O&M, capital and deferral estimates included in this RRA, including Pension and OPEB expenses, under the US GAAP scenario in 2012 and 2013 in accordance with BCUC Order G-117-11. This contrasts with FEU's calculation of pension and OPEB estimates for 2011, which was done as a result of the requirement to adopt IFRS by January 1, 2011 at the time of filing the 2010-2011 Revenue Requirements. (Prior to that date, we had calculated pension and OPEB estimates under Canadian GAAP.)

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5.3.2.3 Codes and Regulations

Codes and Regulations funding requirements are driven by the Companies' need to comply with existing codes and regulations as well as anticipated new or changed codes and regulations. The UCA, *Oil and Gas Commission Act*, *Workers' Compensation Act*, *Environmental Management Act*, *Safety Standards Act*, fire codes and safety standards, Provincial and Federal Emergency Acts, and Canada Standards Association Codes are some of the key codes and legislation with which the Company must be in compliance. These, along with other legislation, regulations, and bylaws, define FEU's level of reporting and compliance activities. These

Table 5.3-6: Mainland 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	43,153	(54)	1,738	120	-	160	2,410	4,375	47,528
Transmission	14,994	(57)	244	(130)	133	91	1,005	1,287	16,280
Energy Supply & Resource Development	3,748	(14)	125	-	-	-	84	195	3,943
Customer Service	56,935	(15)	120	-	(1,653)	-	-	(1,548)	55,388
Energy Solution & External Relations	14,370	(4)	606	750	1,616	-	85	3,054	17,423
Information Technology	20,095	(185)	233	4	-	-	1,358	1,410	21,505
Operations Engineering	13,288	(122)	326	533	-	(190)	242	788	14,076
Operations Support	9,847	(91)	675	352	67	-	387	1,391	11,238
Facilities	6,201	(57)	24	-	-	-	262	228	6,430
Human Resources	8,280	(14)	265	59	-	313	65	687	8,966
Environmental & Safety	2,615	(5)	76	50	36	-	121	278	2,893
Finance and Regulatory	9,953	(1)	417	-	457	-	62	935	10,888
Corporate	11,201	(27)	3,566	-	-	-	(1,110)	2,429	13,630
Total	214,680	(645)	8,416	1,738	656	374	4,971	15,509	230,189

Table 5.3-7: Mainland 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	47,528	-	1,307	600	-	270	1,128	3,305	50,833
Transmission	16,280	-	185	(75)	106	(46)	1,048	1,218	17,499
Energy Supply & Resource Development	3,943	-	99	-	-	-	154	253	4,196
Customer Service	55,388	-	553	-	3,018	-	-	3,571	58,959
Energy Solution & External Relations	17,423	-	489	100	299	-	128	1,015	18,439
Information Technology	21,505	-	290	-	-	-	475	765	22,270
Operations Engineering	14,076	-	378	44	-	-	135	557	14,633
Operations Support	11,238	-	252	65	10	-	237	564	11,802
Facilities	6,430	-	62	-	-	-	(139)	(77)	6,353
Human Resources	8,966	-	265	-	-	-	151	416	9,382
Environmental & Safety	2,893	-	52	35	50	-	27	164	3,057
Finance and Regulatory	10,888	-	328	-	-	-	-	328	11,216
Corporate	13,630	-	(1,811)	-	-	-	645	(1,166)	12,464
Total	230,189	-	2,448	769	3,483	224	3,990	10,914	241,103

Table 5.3-8: Vancouver Island 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	5,379	(31)	87	-	-	-	353	409	5,787
Transmission	6,134	(41)	62	(92)	-	-	693	621	6,755
Energy Supply & Resource Development	100	-	-	-	-	-	-	-	100
Customer Service	5,459	(3)	-	-	(198)	-	-	(201)	5,257
Energy Solution & External Relations	1,464	(1)	37	150	-	-	7	193	1,657
Information Technology	421	(0)	1	-	-	-	-	1	422
Operations Engineering	679	(2)	-	-	-	-	-	(2)	677
Facilities	1,618	(5)	-	-	-	-	(150)	(155)	1,463
Finance and Regulatory	383	(0)	-	-	89	-	-	89	472
Corporate	11,065	(1)	217	-	-	-	2,245	2,461	13,526
Total	32,702	(85)	404	58	(109)	-	3,147	3,415	36,117

Table 5.3-9: Vancouver Island 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Year End Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	5,787	-	139	40	-	-	402	582	6,369
Transmission	6,755	-	63	45	-	-	201	308	7,064
Energy Supply & Resource Development	100	-	-	-	-	-	-	-	100
Customer Service	5,257	-	-	-	342	-	-	342	5,599
Energy Solution & External Relations	1,657	-	30	-	-	-	7	37	1,694
Information Technology	422	-	4	-	-	-	-	4	426
Operations Engineering	677	-	-	-	-	-	-	-	677
Facilities	1,463	-	-	-	-	-	(924)	(924)	539
Finance and Regulatory	472	-	-	-	-	-	-	-	472
Corporate	13,526	-	(223)	-	-	-	(11)	(234)	13,292
Total	36,117	-	13	85	342	-	(325)	115	36,232

Table 5.3-10: Whistler 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	451	-	21	-	-	-	(44)	(23)	428
Customer Service	156	-	-	-	(10)	-	-	(10)	146
Corporate	261	(1)	-	-	-	-	70	69	330
Total	868	(1)	21	-	(10)	-	27	36	904

Table 5.3-11: Whistler 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	428	-	6	-	-	-	(6)	(0)	428
Customer Service	146	-	-	-	8	-	-	8	154
Corporate	330	-	-	-	-	-	1	1	331
Total	904	-	6	-	8	-	(6)	9	913

Table 5.3-12: Fort Nelson 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations *	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	347	-	-	-	-	-	(4)	(4)	344
Customer Service	136	-	-	-	(136)	-	-	(136)	-
Corporate	329	-	-	-	-	-	211	211	541
Total	812	-	-	-	(136)	-	208	72	884

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

Table 5.3-13: Fort Nelson 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	344	-	-	-	-	-	7	7	350
Corporate	541	-	-	-	-	-	21	21	561
Total	884	-	-	-	-	-	27	27	911

5.3.4 EMPLOYEES

FEU will be increasing its staffing levels over the forecast period, driven primarily by the in-sourcing of Customer Service functions. Table 5.3-14 below provides the forecast employee levels for the 2012 and 2013 periods with the most recent years (2010 and 2011) included for comparison. Similar tables along with explanations for changes year over year are also provided for each department in their respective sections.

Not all the employees and their associated labour hours and dollars are for support of O&M activities. To provide clarity regarding the employee distribution, the employees have been allocated between O&M, Capital and Deferral activities (i.e. EEC programs).

Table 5.3-14: Growing Employees to Support In-Sourced Customer Service and Enhanced Reliability[79]

SUMMARY

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	1,294	1,314	1,311	1,692	1,701	1,701
Vancouver Island	111	107	122	124	123	124
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	1,411	1,425	1,438	1,821	1,828	1,829

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	298	282	287	671	358	358
Vancouver Island	39	31	40	45	42	42
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	337	313	327	716	400	400

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	996	1,032	1,024	1,021	1,343	1,343
Vancouver Island	72	76	82	79	81	82
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	1,074	1,112	1,111	1,105	1,428	1,429
Dependant Contractors excluded	23	15	23	3	3	3

The requirements driving the overall employee numbers are described in each of the individual department discussions in Sections 5.3.5 through to 5.3.16.

The 2010 Approved and Actual, and the 2011 Approved employees listed in Table 5.3-14 above do not include any employees hired into the Customer Service Department as a result of the approval of the Customer Care Enhancements Certificate of Public Convenience and Necessity ("CPCN") Project (the "CCE Project"). The Customer Service department accounts for 331 of

[79] Employees in this Section are the number of Full Time Equivalent employees as at December 31. Starting in 2011, dependant contractors have been mostly replaced by employees, reducing their numbers from 23 to 3 with an offsetting increase in Capital and O&M employees, as shown in the 2011 Projection. The dependant contractors are all IBEW; this change in status is more fully explained in the Operations O&M Section 5.3.5

Table 5.3-15: Distribution O&M Forecast to Meet Future Requirements

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 40,438	$ 41,887	$ 43,153	$ 43,153	$ 47,528	$ 50,833
Vancouver Island	$ 5,626	$ 5,238	$ 5,379	$ 5,379	$ 5,787	$ 6,369
Whistler	$ 446	$ 383	$ 451	$ 451	$ 428	$ 428
Fort Nelson	$ 359	$ 338	$ 347	$ 347	$ 344	$ 350
Total	$ 46,869	$ 47,846	$ 49,330	$ 49,330	$ 54,086	$ 57,980

Table 5.3-16: Distribution Employees to Meet Future Requirements

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	536	519	539	571	577	586
Vancouver Island	80	72	80	82	79	79
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	622	595	624	658	661	670

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	176	153	162	201	195	197
Vancouver Island	39	31	39	44	41	41
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	215	184	201	245	236	238

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	360	367	377	370	382	389
Vancouver Island	41	41	41	38	38	38
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	407	411	423	413	425	432

For a discussion of the Distribution capital expenditures, please refer to Section 6.2.

2011 PROJECTION VERSUS 2011 ALLOWED

The 2011 Projected Distribution O&M of $451 thousand is expected to equal the Allowed amount under the 2010-2011 RRA. The reduction in Distribution Manager costs is permanent; however, in 2011 these savings are expected to be offset by continued system stabilization repair work (gas odour calls, leak repairs, meter set maintenance). These activities have increased as Whistler conversion customers were encouraged to call in upon the detection of any gas odour to ensure the many fittings touched during the conversion were tightened and that the conversion had been completed safely and to the customers' satisfaction.

5.3.5.6 Distribution 2010 and 2011 Review - Fort Nelson

2010 ACTUAL VERSUS 2010 ALLOWED

The principal reasons the 2010 actuals varied from the allowed amount were due to reductions in vehicle and employee related expenses.

2011 PROJECTION VERSUS 2011 ALLOWED

The 2011 Projected Distribution Fort Nelson O&M of $347 thousand is expected to equal the allowed amount as part of the 2011 Fort Nelson RRA.

5.3.5.7 Distribution 2012 and 2013 Forecast – Mainland

The Mainland requires incremental O&M in 2012 and 2013 to ensure we continue to provide safe, reliable, cost-effective service to our customers. The requirements are presented under the following three cost driver categories and are summarized in Table 5.3-17 below:

1. Codes and Regulations;
2. Demographics; and
3. Service Standards and Reliability.

Table 5.3-17: Increases Required to Meet Mainland Regulatory Requirements and Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	43,153	(54)	1,738	120	-	160	2,410	4,375	47,528
2013	47,528	-	1,307	600	-	270	1,128	3,305	50,833

such as the Gateway projects in the Lower Mainland. FEI requires $448 thousand of O&M in 2012 and $58 thousand of O&M in 2013 to hire the additional resources to manage the workload and maintain service standards in the Operations Centre group.

The Operations Centre will require six additional positions in 2012 and three additional positions in 2013 to address the increase in workload. In 2012, three Planners and three Operational Support Representatives ("OSRs") in the Closing and System Survey sub-group of the Distribution group are required. In 2013, three additional Planners, including a work-leader to supervise a large planning group, are required. The Planners, who typically meet on construction sites with homeowners, developers and municipalities to design and cost estimate gas system infrastructure, are required primarily for capital activities; however, they also engage in training, supervision and reviews of municipal project plans which are classified as O&M activities.

ASSET MANAGEMENT

The Asset Management group requires an analyst and assistant in 2012 ($160 thousand). Two assistants are required in 2013 ($140 thousand). These roles will support O&M, capital, sustainment planning and the biomethane programs. The existing and new assets require maintenance planning and administration to ensure ongoing safety, reliability and cost effectiveness. Asset Management must be adequately staffed with skilled personnel in order to manage the increased workload (biomethane assets, internal reporting and data management to improve asset management) and meet customer and regulatory requirements. Asset Management requires adequate skilled resources to ensure capital investments are properly screened, prioritized and administered.

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Distribution also requires a reporting analyst ($90 thousand) to manage steadily growing internal and external operational reporting requirements as well as reporting technology changes and individual and departmental performance management. Distribution also requires a process support analyst ($70 thousand) to manage the increase in system applications supported and number of users.

FIELD SERVICE DELIVERY

Field Service Delivery includes six primary work categories: Preventive Maintenance, Corrective Maintenance, Operations, Meter Exchange, Emergency Management and Meter to Cash. The Field Service Delivery budget is the largest component of the Distribution budget at $20.8 million. Incremental increases in O&M of $416 thousand in 2012 and $272 thousand in 2013 are required in the category of Service Standards and Reliability for field service delivery activities. The changes in budget requirements are caused by changes in activity levels and unit costs. Activity levels are impacted by system and customer growth and maintenance frequencies. Unit costs are impacted by labour/vehicle rates as well as the efficiency and experience of the employees and contractors performing the activities. 2012 and 2013 forecast unit costs primarily reflect the 2010 experience together with inflation.

A new area within the Preventive Maintenance category is the budget to operate and maintain NGV and biomethane assets.

Regular operation and maintenance of NGV assets, specifically CNG and/or LNG stations, are required to ensure public safety and reliability. Starting in 2012, the O&M costs will be forecast in Distribution, and as the number of NGV assets increases, the operation and maintenance requirements will increase. The Mainland requires $115 thousand in 2012 and no incremental costs in 2013 to operate and maintain the NGV assets. A summary of all NGV costs and revenues is included in Appendix I.

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Biomethane service received a two-year Commission approval for inclusion in the regulated natural gas utility business. Regular operation and maintenance of biomethane assets, similar to pressure regulating stations, is required. Starting in 2012, the O&M costs will be forecast in Distribution, and as the number of biomethane assets increase, the operation and maintenance requirements will increase. The Mainland requires $23 thousand in 2012 and an incremental $68 thousand in 2013 to operate and maintain the biomethane assets. A summary of all biomethane costs and revenues is included in Appendix J.

Also included in the Field Service Delivery category, driven by changes in activity levels and inflation in unit costs or a combination thereof, are additional funds for:

- Battery upgrades for industrial meters ($160 thousand);
- Bridge crossing repairs ($110 thousand);
- Station transition repairs ($100 thousand);
- Leak repairs ($110 thousand);
- Line locates ($125 thousand);
- Valve inspections ($200 thousand);
- Gas odour calls ($200 thousand); and
- Meter to cash (lock-offs, etc.) ($1.13 million).

These additional requests are partially offset by the following savings:

- Operations – general (primarily line heater fuel) ($590 thousand);
- First response standby ($440 thousand); and
- Meter to cash recoveries ($1.12 million). The Companies plan to increase the reconnection/reactivation fee to $100 (regular hours) and $140 (after hours) as allowed

Table 5.3-19: Efficiencies Realized in Meeting Whistler Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	451	-	21	-	-	-	(44)	(23)	428
2013	428	-	6	-	-	-	(6)	(0)	428

SERVICE STANDARDS AND RELIABILITY

The costs for Whistler are forecast to decrease in the 2012-2013 period from 2011 due primarily to the reduction in management costs and declining system post-conversion repairs. Partially offsetting these reductions are annual inflation and scheduled commercial/industrial meter maintenance ($20 thousand) coming due in 2012 that is on a three year cycle.

5.3.5.10 Distribution 2012 and 2013 Forecast - Fort Nelson

Fort Nelson requires similar O&M levels in 2012 and 2013 as compared to 2011 to ensure we continue to provide safe, reliable, cost-effective service to our customers. Some minor inflationary wage pressures are offset by some minor expense and material savings which together are embedded in the Service Standards and Reliability category. The Fort Nelson operation consists of three employees and the annual expenditure requirement is a mix of direct costs and allocated costs from FEI.

Table 5.3-20: Changes in O&M to Meet Fort Nelson Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	347	-	-	-	-	-	(4)	(4)	344
2013	344	-	-	-	-	-	7	7	350

5.3.5.11 Transmission O&M Expenditures and Employees

Code and regulations compliance forms the foundation of many of our operating programs and activities in the Transmission area. Code changes, asset age, asset base expansion, and inflation all drive the need for incremental O&M funding in the Transmission group to allow FEU to continue to provide natural gas service in a safe and reliable manner. Table 5.3-21 sets out approved, actual, projected, and forecast O&M costs for Transmission. These costs are reviewed later in this section.

Table 5.3-43: IT Department O&M Increases to Maintain Service Standards and Reliability

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 18,353	$ 17,012	$ 20,095	$ 20,095	$ 21,505	$ 22,270
Vancouver Island	$ 423	$ 387	$ 421	$ 421	$ 422	$ 426
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 18,776	$ 17,400	$ 20,516	$ 20,516	$ 21,927	$ 22,696

The costs of IT employees (M&E and COPE) are included in the O&M costs that are set out in Table 5.3-43 above, as well as being included in IT capital projects. Table 5.3-44 that follows sets out approved, actual, projected, and forecast employees for IT.

Table 5.3-44: Employees Supporting IT Department Operations

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	63	64	63	65	74	75
Vancouver Island	1	1	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	64	65	64	66	75	76

Capital/Deferral Employees

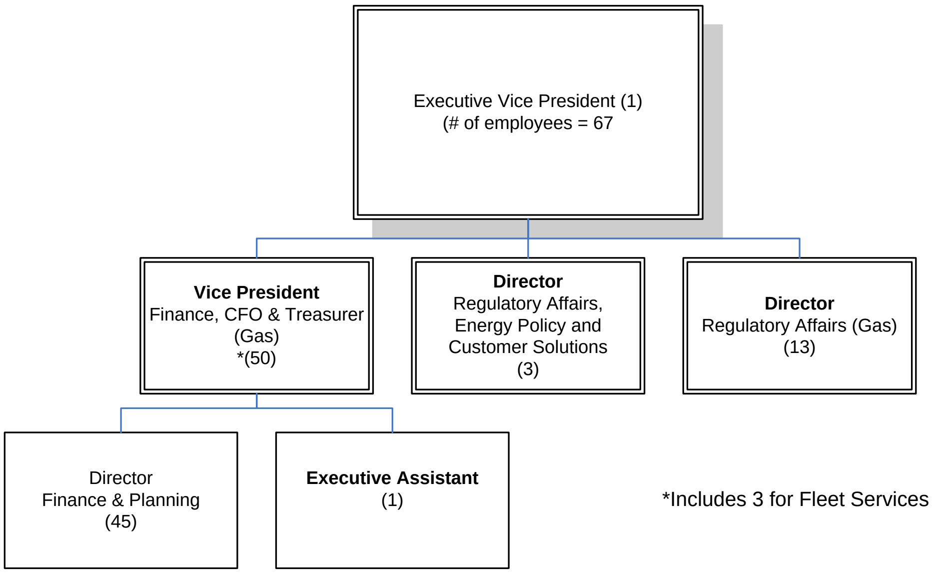
Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	6	6	6	6	9	9
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	6	6	6	6	9	9

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	57	58	57	59	65	66
Vancouver Island	1	1	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	58	59	58	60	66	67

FINANCE AND REGULATORY AFFAIRS ORGANIZATION CHART

Figure 5.3-11: Organization Chart for Finance and Regulatory



5.3.15.2 Finance and Regulatory Affairs O&M Expenditures and Employees

In order to continue to successfully meet the requirements of our various stakeholders, the Finance and Regulatory Affairs department requires the forecast expenditures and headcount for the 2012 and 2013 test years as shown in Tables 5.3-64 and 5.3-65 below. The Companies believe these forecast expenditures are reasonable, and consistent with expenditure levels observed in recent years.

Table 5.3-64: Finance and Regulatory O&M Forecast to Meet Future Requirements

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 9,616	$ 9,343	$ 9,953	$ 9,953	$ 10,888	$ 11,216
Vancouver Island	$ 380	$ 381	$ 383	$ 383	$ 472	$ 472
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 9,997	$ 9,724	$ 10,336	$ 10,336	$ 11,360	$ 11,688

Table 5.3-65: Finance and Regulatory Employees to Meet Future Requirements

	Total Employees					
Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	69	68	69	69	69	69
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	69	68	69	69	69	69

The number of employees is expected to remain unchanged during the forecast period. An overview of the O&M changes is provided in Sections 5.3.15.3 through 5.3.15.5 below.

5.3.15.3 Finance and Regulatory Affairs 2010 and 2011 Review – Mainland

During 2010 the Finance and Regulatory Affairs department spending was below the 2010 approved budget. Labour savings resulting from staff turnover and vacancies contributed to the lower spending for the FEU as per Table 5.3-65 above.

In 2011, as vacancies have been filled and the staffing levels in Finance and Regulatory Affairs normalize, the department is expected to meet its budget.

The 2010 Actuals and 2011 Projection O&M are in line with the approved amounts, with the exception of the labour challenges discussed above. The Finance and Regulatory department remains committed to providing the necessary support to the various departments within the FEU in order to achieve our overall organizational commitments.

5.3.15.4 Finance and Regulatory Affairs 2012 and 2013 Forecast – Mainland

Finance and Regulatory Affairs will require the forecast incremental expenditures for 2012 and 2013, described further below, to continue to provide the expected level of service.

The total forecast O&M for the Mainland Finance and Regulatory Affairs departments in 2012 of $10.9 million is comprised of the following:

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- $7.44 million of compensation and related costs for the 69 COPE and M&E staff. The employee group is a mix of professionals (Chartered Accountants, Certified General Accountants, Certified Management Accountants and MBA graduates) holding management and senior analyst positions, and other non professional staff providing clerical and administrative services;

- $3.17 million of fees (including BCUC quarterly assessments, audit and filing fees, bank charges, contractor fees and other); and
- $0.28 million for employee training costs, travel expenses, miscellaneous administrative costs, materials and supplies, and professional membership dues.

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The table below shows the incremental change in the Mainland Finance and Regulatory Affairs department O&M for 2012 and 2013.

Table 5.3-66: Increased O&M is Required to Stakeholder Needs and Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	9,953	(1)	417	-	457	-	62	935	10,888
2013	10,888	-	328	-	-	-	-	328	11,216

CUSTOMER & STAKEHOLDER EXPECTATIONS

In 2012, the $457 thousand increase in this category includes the following: $300 thousand to reflect recent experience of higher BCUC quarterly assessments (in 2010 the actual BCUC fees were $300 thousand greater than the approved amount), $67 thousand for the change in accounting audit fees due to the transition to US GAAP, and $90 thousand due to the new requirements around emission reporting as described in Section 5.3.14.3 (starting 2011 the *Greenhouse Gas Emissions Act* requires external verification/audit of greenhouse gas emissions reporting).

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SERVICE STANDARDS & RELIABILITY

In 2012, the $62 thousand increase in this category is due to non-labour inflation.

5.3.15.5 Finance and Regulatory Affairs 2012 and 2013 Forecast - Vancouver Island

Finance and Regulatory Affairs O&M in Vancouver Island consists of BCUC Quarterly Assessments, audit fees and bank charges. The table below shows the incremental change in the Finance and Regulatory Affairs department O&M for 2012 and 2013.

Table 5.3-67: Finance & Regulatory Incremental O&M on Vancouver Island

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	383	(0)	-	-	89	-	-	89	472
2013	472	-	-	-	-	-	-	-	472

CUSTOMER & STAKEHOLDER EXPECTATIONS

The 2012 forecast increase of $89 thousand in this category includes the following: $50 thousand increase in BCUC quarterly assessments; $29 thousand in accounting audit fees due to the transition to the US GAAP, and $10 thousand increase driven by the government policy around emission reporting. The rationale for seeking these increases is discussed in Section 5.3.15.4, above.

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In 2013, the total Vancouver Island O&M forecast for the Finance and Regulatory Affairs is expected to remain unchanged from the 2012 level.

5.3.15.6 Finance and Regulatory Affairs Summary

The increases in Finance and Regulatory Affairs O&M sought in this Application are primarily driven by inflation and changes in Stakeholder Expectations. They represent the resources needed to meet compliance standards and the requirements of regulatory stakeholders.

5.3.16 CORPORATE

5.3.16.1 Corporate Departmental Overview

The Corporate department provides overall management and leadership for the FortisBC Energy Utilities.

The Corporate department centralizes certain corporate wide cost items including: external legal fees, company insurance premiums, the retiree portions of the pension expense and the OPEB costs, FortisBC Holdings Inc. ("FHI") corporate services fees, industry association fees (i.e. Canadian Gas Association, Western Energy Institute), shared service charges and recoveries between affiliated utilities and shared service recoveries from CMAE, and recoveries from non-regulated businesses.

5.3.16.2 Corporate O&M Expenditures and Employees

The overall O&M and employee labour requirements for the Corporate department for the four regions are outlined in Tables 5.3-68 and 5.3-69 below. These forecast expenditures reflect the allocation of common costs to the various Companies as discussed further in Section 5.3.18.

Table 5.3-68: Corporate O&M for the Forecast Period

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 11,274	$ 13,915	$ 11,201	$ 11,201	$ 13,630	$ 12,464
Vancouver Island	$ 11,057	$ 10,506	$ 11,065	$ 11,065	$ 13,526	$ 13,292
Whistler	$ 251	$ 264	$ 261	$ 261	$ 330	$ 331
Fort Nelson*	$ 317	$ 321	$ 329	$ 329	$ 541	$ 561
Total	$ 22,898	$ 25,007	$ 22,856	$ 22,856	$ 28,027	$ 26,649

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

Table 5.3-69: Staffing in the Corporate Department

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	2	1	2	1	1	1
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	2	1	2	1	1	1

There are several cost drivers for the Corporate operating costs. Corporate legal fees are influenced by the level of external legal support required by the different departments in the FortisBC Energy Utilities. The Companies' insurance premiums are affected by a number of factors such as the insurance company's insured losses, coverage levels and investment income.

In addition, included under the Corporate department are the shared services costs/recoveries between regulated affiliates as well as the corporate services management fee from FHI. The amounts of inter-company charges are based on the level of activities performed and are governed by the Shared Services Agreements and the Corporate Services Agreement. These agreements benefits the organizations involved as they enable the FEU to harvest the benefits of economies of scale by having a single corporate management and support structure while avoiding duplication of work, and allowing customers to benefit from the efficiencies realized.

For 2010 and 2011 in the Whistler and Fort Nelson regions, O&M tracked very close to the approved amounts. In 2010, the $2.59 million higher cost for the Mainland region is primarily driven by executive retirements and the $550 thousand favourable variance on Vancouver Island was due to lower support costs including employee incentive plan related costs.

With the retirement of FEU's past president in 2010, the number of employees became one and is expected to remain unchanged during the forecast period.

The changes in Corporate O&M for the forecast periods are described in Section 5.3.16.3 thorough 5.3.16.6 below.

5.3.16.3 Corporate 2012 and 2013 Forecast - Mainland

The total Mainland O&M forecast for the Corporate department in 2012 of $13.63 million is comprised of the following: $10.72 million for the FHI corporate services fee, $4.4 million for insurance premiums, $7.67 million for retiree portions of employee pension and OPEB expenses, $1.4 million for supporting costs, $623 thousand for corporate legal expenses, and $467 thousand in cross charges from FortisBC Inc.; offset by a $11.04 million credit for shared services recoveries from Vancouver Island, Whistler, Fort Nelson, Thermal Energy Services, and CMAE.

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In addition, included in the $13.63 million is a one-time $616 thousand credit for a shared services true-up. In its 2010 – 2011 Revenue Requirement Application, FEI proposed to include in its 2012 O&M forecast a two year cumulative shared services true-up of actual costs between FEI and FEVI and FEW. Consistent with this approach, included in the 2012 Corporate O&M forecast is a $616 thousand one time true-up of the shared services recoveries ($600 thousand from FEVI and $16 thousand from FEW.) These estimates are based on the observed 2010 actual levels of shared services between FEI and other FEU Companies. In 2010, shared Services provided to FEVI were $300 thousand higher than approved, whereas the shared Services provided to FEW were $8 thousand higher than the approved. The Companies have forecast the 2011 level of Shared Services to mirror the observed 2010 actual levels, so the true-up for each year is the same amount.

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Table 5.3-70 below shows the year over year changes broken down by the five cost drivers.

Table 5.3-70: Mainland Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	11,201	(27)	3,566	-	-	-	(1,110)	2,429	13,630
2013	13,630	-	(1,811)	-	-	-	645	(1,166)	12,464

LABOUR INFLATION AND BENEFITS

An increase in this category in 2012 and a decrease in 2013 are due to the changes in the past service cost component of pensions and OPEBs as described in Section 5.3.2.2.

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SERVICE STANDARDS AND RELIABILITY

In 2012, the $1.11 million net decrease in this category includes the following items:

- A decrease in costs resulting from an increase in shared services fee recoveries from Vancouver Island, Fort Nelson and Whistler of $1.69 million and the one-time $616 thousand credit for 2010 and 2011 shared services fee recoveries from FEVI and FEW as described above; offset by
- A $1.07 million increase in the corporate cervices fee from FHI and a $125 thousand increase which is the net result of an increase in executive cross changes from FortisBC Inc. and removing the salary of FEU's past president, and an inflationary increase in supporting costs.

In 2013, the $645 thousand net increase in this category is primarily due to:

- a $616 thousand increase due to the removal of the one-time shared services true-up discussed above;
- a $311 thousand increase in the corporate services fee from FHI;
- $220 thousand in higher insurance premiums representing a 5 percent increase over the 2012 estimate;
- a $46 thousand increase in supporting costs; offset by
- $550 thousand higher shared services recoveries from Vancouver Island, Whistler and CMAE.

Please see Section 5.3.18 for a thorough discussion of Shared Services and Corporate Services.

5.3.16.4 Corporate 2012 and 2013 Forecast - Vancouver Island

The total Vancouver Island O&M forecast for the Corporate department in 2012 of $13.53 million is comprised of the $9.04 million shared service fee allocated from the Mainland, the $600 thousand one-time Shared Service true-up discussed above, $1.14 million corporate service fee allocated from FHI, $1.08 million for retiree portions of employee OPEB and pension expenses, $1.04 million for insurance premiums and $630 thousand of supporting costs.

Please refer to the Table 5.3-71 below for the year over year changes broken down by the five cost drivers.

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Table 5.3-71: Vancouver Island Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	11,065	(1)	217	-	-	-	2,245	2,461	13,526
2013	13,526	-	(223)	-	-	-	(11)	(234)	13,292

LABOUR INFLATION AND BENEFITS

An increase in this category in 2012 and a decrease in 2013 are due to the changes in the past service cost component of pensions and OPEBs as described in Section 5.3.2.2.

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SERVICE STANDARDS AND RELIABILITY

In 2012, the $2.25 million increase in this category is primarily due to a $1.5 million increase in the shared service fee from the Mainland, the $600 thousand one-time true up discussed above, $110 thousand increase in insurance premiums and a $35 thousand increase in supporting costs.

The increase in the shared service fee is reflective of the increase in O&M for the Mainland business areas which provide operational support but do not charge their cost directly to Vancouver Island.

In 2013, the $11 thousand decrease is primarily due to a removal of the $600 thousand one-time shared service true-up, offset by a $500 thousand increase in the shared service fee from the Mainland, $39 thousand increase in the FHI corporate services fee and $50 thousand increase in the insurance premium.

5.3.16.5 Corporate 2012 and 2013 Forecast - Whistler

The total Whistler O&M forecast for the Corporate Services department in 2012 of $330 thousand is comprised of $251 thousand in shared service fees allocated from the Mainland, $48 thousand of corporate services fees from FHI, a $16 thousand one-time true-up of shared services discussed above and $15 thousand of supporting costs.

Table 5.3-72: Whistler Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	261	(1)	-	-	-	-	70	69	330
2013	330	-	-	-	-	-	1	1	331

SERVICE STANDARDS AND RELIABILITY

In 2012 the $70 thousand increase in this category is driven by a $39 thousand increase in the shared service fee from the Mainland, a $16 thousand one-time true up discussed above, and a $15 thousand increase in insurance premiums.

In 2013, the $1 thousand increase is due to a $17 thousand increase in the shared service fee from Mainland offset by the removal of $16 thousand one-time true-up included in 2012 and discussed above.

5.3.16.6 Corporate 2012 and 2013 Forecast - Fort Nelson

For financial reporting purposes, the O&M costs for Fort Nelson are included in the overall operating and maintenance expense of Mainland. For regulatory reporting purposes, an allocation from Mainland Corporate O&M is made, recognizing the functional support provided to Fort Nelson. This approach is consistent with the past practice and was approved by Commission Order No. G-27-08.

The increase in Corporate O&M is driven by an increase in the Mainland O&M which is used as an allocation base for Fort Nelson and the 2012 reclassification of Customer Service costs. Following the in-sourcing of the customer service function in 2012, customer service related costs are no longer being captured under the Customer Service department. Instead these costs are included as part of Corporate costs and calculated based on the methodology describe above.

Table 5.3-73: Fort Nelson Corporate Incremental O&M

Year (in $000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012*	329	-	-	-	-	-	211	211	541
2013	541	-	-	-	-	-	21	21	561

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

5.3.16.7 Corporate Summary

For 2010 and 2011, FEU and stakeholders agreed that the requested level of Corporate O&M was appropriate to provide the required leadership to the Companies in an effective and efficient manner. The Corporate department requires the above levels of forecast expenditures for 2012 and 2013 and believes the forecast expenditures are reasonable and appropriate.

FBC. The change being requested should simplify the charges between the two entities as both move towards a more shared management structure. Additionally, FEU has reviewed the overhead charge between the gas customers and the AES customers and has proposed a fee based on the expected utilization of services by the AES customers. Other than these proposed changes, the current transfer pricing policies are appropriate for the period of this Application.

5.3.18.4 Summary of Corporate and Shared Services

In summary, this section has described the corporate services provided by Fortis Inc. and FHI to the FEU and how the FEU share costs amongst each other and with FBC. The relationship between the FEU, FHI and Fortis Inc. is generally unchanged from the time of filing of the 2010/2011 RRA. Certain organizational changes as a result of a shared executive team have changed the relationship between the FEU and FBC. The shared executive team has resulted in cross charges between FEU and FBC for the portion of executive time spent on each others business. Shared services across the FEU is similar to what was filed in the 2010/2011 RRA. While the costs are different, the drivers of those costs are as filed in the 2010/2011 RRA.

5.3.19 SUMMARY OF OPERATIONS AND MAINTENANCE EXPENSE

The Companies' 2012 and 2013 O&M forecasts reflect the changes in operating requirements that are anticipated over the forecast period. In particular, incremental funding requests are driven by five requirements – labour inflation and benefits, codes and regulations, customer and stakeholder expectations, demographics, and a continued focus on service standards and reliability. In total, these drivers serve to increase O&M by 7.6 percent in 2012 and 4.1 percent for 2013. The FEU believe that the O&M levels that have been forecast prudently reflect the known and expected impacts of their operating environment, and required increases related to safety and regulatory requirements.

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5.4 Depreciation and Amortization

5.4.1 INTRODUCTION TO DEPRECIATION AND AMORTIZATION

The FortisBC Energy Utilities received approval to update their depreciation rates, excluding any amount for recovery of negative salvage, effective January 1, 2010. Excerpts from the relevant Commission Orders follow.

Appendix A to Order G-141-09 approving the Negotiated Settlement Agreement in the 2010-2011 FEI (then Terasen Gas Inc.) Revenue Requirement Application states:

"22. Depreciation Study

that time, the accumulated depreciation balances were transferred to the SAP accounting system as one amount for each asset class. Then, a program was run that calculated what the accumulated depreciation should have been given the current depreciation rates in the system and the age of the assets, and an entry was created to split the accumulated depreciation into two components – one to reflect the current remaining life of the existing assets, and the balance to the accumulated loss component. This calculation was done because historically Vancouver Island had never calculated losses on retirement and it was decided an estimation of the accumulated losses was required. As we have no ability to determine in hindsight the accuracy of this allocation, there is no further analysis that can be completed. Excluding these disaggregation entries and incurred removal costs of approximately $1.4 million, the accumulated loss balance at the end of 2009 would only be in the order of $1.6 million.

As demonstrated in the report included in Appendix E-3, the accumulated losses represent investments in utility plant required to continue providing service to customers, and have resulted from a number of factors, reflecting the environment that a natural gas utility operates in. In addition, and although not specifically addressed in the report included in Appendix E-3, a portion of the accumulated losses also results from inadequate recovery of depreciation from past customers. Adjustments to depreciation rates are required on a regular basis to reflect changes in the expected lives of assets. The past practice of deferring depreciation rate increases has contributed to losses being accumulated. Although the approval of previously recommended increases in depreciation rates would not have resulted in a material reduction in the balance of accumulated losses that existed at the end of 2009, they were designed to address the recovery of those losses over the expected lives of the assets.

Consistent with past practice, the depreciation rates included in the Depreciation Study filed with this Application include a portion related to the recovery of the unrecognized loss balances that were accumulated prior to 2010.

Net losses realized subsequent to 2009 have been recorded in a deferral account instead of in accumulated depreciation, as agreed to in the 2010-2011 Negotiated Settlement. As discussed in Section 6.3, the FEU propose to maintain this treatment for 2012 and 2013, and have proposed a 20 year amortization period for the deferral account that is aligned with the average service life of the asset categories that are contributing to the losses. This treatment will achieve the same result for ratepayers as the historical treatment followed by the Utilities and provided for in the BCUC Uniform System of Accounts.

5.4.5 AMORTIZATION OF CONTRIBUTIONS IN AID OF CONSTRUCTION ("CIAC")

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For FEI, the amortization rate of 2.89 percent for Distribution CIAC has been determined based on the average depreciation rate for the relevant distribution asset classes, namely, 473 Services, 474/478 Meters, and 475 Mains. The depreciation rate of 1.68 percent for Transmission CIAC has been determined based on the average depreciation rate for the

Table 5.5-3: Lower Late Payment Charges Forecast for Vancouver Island

($thousands) Vancouver Island	Approved 2011	Forecast 2012	Forecast 2013
Late Payment Charges	$ 345	$ 223	$ 224
Connection Charges	380	399	409
NSF Returned Cheque Charges	5	3	3
Other Recoveries	2	-	-
Total	**$ 732**	**$ 625**	**$ 636**

Table 5.5-4: Lower Late Payment Charges Forecast for Whistler

($thousands) Whistler	Approved 2011	Forecast 2012	Forecast 2013
Late Payment Charges	$ 49	$ 11	$ 11
Connection Charges	5	4	4
NSF Returned Cheque Charges	-	-	-
Other Recoveries	2	1	1
Total	**$ 56**	**$ 16**	**$ 16**

Table 5.5-5: Lower Late Payment Charges Forecast for Fort Nelson

($thousands) Fort Nelson	Approved 2011	Forecast 2012	Forecast 2013
Late Payment Charges	$ 38	$ 13	$ 13
Connection Charges	20	11	11
NSF Returned Cheque Charges	-	-	-
Other Recoveries	2	-	-
Total	**$ 60**	**$ 24**	**$ 24**

5.5.3 MAINLAND – VANCOUVER ISLAND WHEELING CHARGES

The Vancouver Island Wheeling Agreement, as approved by Commission Order No. G-149-07, is up for renewal at October 1, 2011. Under section 17.2 of the Wheeling Agreement, FEVI has the option to extend the term for 20 years with the demand rate for the first year of the renewal period determined in reference to the payment in the final year of the initial agreement.

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FEVI will exercise its option to extend the agreement and there will be no changes to the determination of Wheeling Charges. Therefore, for the purposes of determining the 2012 and 2013 revenue requirements, FEI has calculated the Vancouver Island Wheeling Charge using the approved 2011 demand rate and has updated the other components of the charge in

The initial term of the T-South Enhanced Service was May 1, 2010 to April 30, 2012. As a result of the success of this service, Spectra Energy and the Company executed an extension of the Service to October 31 2014 which was approved by the Commission in Order No. G-69-11 dated April 14, 2011.

Any variance from the forecast net mitigation revenues of $5.7 million will be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a five year period. Please refer to Section 6.3 for a discussion on this deferral account.

As discussed above, FEI is seeking approval in this Application for a change in the allocation between the delivery margin and midstream of the SCP costs and revenues, and of the Spectra Energy Kingsvale South charges related to the NWN capacity. As shown in Table 5.5-6 above, the net impact to the forecast annual SCP revenues for 2012 and 2013 of this change, as compared to the approved 2011 SCP revenues, is zero because the allocation of additional costs associated with NWN related Spectra Energy Kingsvale South capacity component is offset by the allocation of an additional $3.3 million in net mitigation revenues associated with the T-South Enhanced Service.

5.5.5 MAINLAND - NATURAL GAS FOR TRANSPORTATION SERVICE REVENUE

Natural Gas for Transportation Service is the compression and dispensing service for CNG fueling and transportation, delivery, fuel storage and dispensing service for LNG fueling. On December 1, 2010 FEI submitted its Application for Approval of a Service Agreement for CNG Service and for Approval of General Terms and Conditions for CNG and LNG Service (the "NGV Application") to the Commission. On April 13, 2011, FEI submitted to the Commission and Interveners our Final Written Reply Submission. The forecasts made in relation to NGVs and NGV fueling infrastructure in the 2012-2013 RRA are premised on the assumption that the NGV Application will be approved as filed. Further, it is also based on the premise that the EEC incentives for NGV will continue. After the Commission's Decision on the NGV Application has been issued, FEI will file an evidentiary update to this Application to the extent required to reflect the Commission's determinations on these matters.

The other revenue forecast of $1.3 million in each of 2012 and 2013 includes two components related to the NGV Application:

4. Fueling station revenue
5. Incremental delivery margin revenue

Table 5.5-8 outlines the components of other revenue associated with CNG and LNG Service included in the determination of the revenue requirements for 2012 and 2013.

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Table 5.5-8: CNG and LNG Service Provide Benefits to All Customers in the Forecast Period

($thousands)	2012	2013
CNG Service Fueling Station Revenue	$ 191	$ 191
LNG Service Fueling Station Revenue	519	519
Total Fueling Station Revenue	711	711
CNG Service Delivery Margin Revenue	45	45
LNG Service Delivery Margin Revenue	549	549
Total Delivery Margin Revenue	593	593
Total CNG Service Revenue	236	236
Total LNG Service Revenue	1,068	1,068
Total CNG and LNG Service Revenue	**$ 1,304**	**$ 1,304**

The fueling station revenue is the recovery of the costs associated with the CNG and LNG fueling stations and reflects existing approved stations. We have forecast CNG Service fueling station revenue of $0.2 million in each of 2012 and 2013. We have also forecast LNG Service fueling station revenue of $0.5 million in each of 2012 and 2013. This results in a total fueling station revenue forecast of $0.7 million in each of 2012 and 2013.

The incremental delivery margin revenue reflects the forecast volume on the delivery system that the CNG and LNG Service fueling stations are expected to provide. The volume is determined by Rate Schedules 6, 23, 25 and 16 and is forecast to provide incremental throughput on the delivery system of 169 TJs in each of 2012 and in 2013 (Table 5.5-9). The volume by rate schedule is multiplied by the existing delivery rate[99] to determine the forecast incremental delivery revenue of $0.6 million in each of 2012 and 2013 that will benefit all existing non-bypass customers.

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[100] Section 7.1 to 7.4, Schedule 25 & 26

Table 5.5-9: Forecast CNG and LNG Fueling Station Volume

Forecast Fueling Station Volume, TJ	2012	2013
CNG Service Volume	31	31
LNG Service Volume	139	139
Total CNG and LNG Service Volume	169	169

Additional information on the NGV Application, including the calculations behind the revenue forecasts, can be found in Appendix I.

5.5.6 MAINLAND BIOMETHANE RECOVERIES

The other revenue amounts of $62 thousand in 2012 and $29 thousand in 2013 represent the transfer of applicable biomethane costs from the delivery margin to the Biomethane Variance Account ("BVA"). This is the forecast cost of service each year associated with the upgrader plant. These costs are to be excluded from delivery rates and included in the Biomethane Energy Recovery Charge in accordance with Commission Order No. G-194-10. Please refer to the discussion on the BVA in Section 6.3, Rate Base Deferral Accounts, as well as the comprehensive Biomethane Report in Appendix J.

5.5.7 VANCOUVER ISLAND LNG MITIGATION REVENUES

LNG Mitigation Revenues commence in 2011 as a result of the Mt. Hayes LNG Facility becoming operational. These revenues reflect a storage and delivery agreement between the Vancouver Island and Mainland utilities for monthly demand charges of $1.0 million, or $12.0 million per year. The storage and delivery agreement was approved by Commission Order No. C-9-07.

5.5.8 SUMMARY OF OTHER REVENUE

The FortisBC Energy Utilities believe that the forecast amounts of other revenue for the years 2012 and 2013 reflect all applicable contracts and fixed revenues and are based on our best knowledge of the factors that drive the variable components.

5.6 Taxes

In carrying out its mandate as a gas service provider, the FortisBC Energy Utilities incur taxes that are imposed by different government bodies. The Companies manage these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the revenue requirement for each Company.

5.6.1 INCOME TAX

The FortisBC Energy Utilities are subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately include these costs in calculating the Companies' 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 25.0 percent for 2012 and 2013. The corporate tax rates used in this RRA are based on the Canada Income Tax Act and the BC Income Tax Act substantively enacted legislation.

As approved by Commission Order No. G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

5.6.2 PROPERTY TAX

Property tax for 2012 and 2013 uses Company forecasts of assessed values of taxable assets, municipal mill rates, and taxes from revenues earned from natural gas consumed within the Municipalities. Property tax also includes the annual fee charged by the Oil & Gas Commission ("OGC"). The following table provides the forecast property tax expense for 2012 and 2013 for purposes of determining revenue requirement and rates for each of the FortisBC Energy Utilities.

Table 5.6-1: Property Tax Expense by Utility/Region[100]

($ thousands) **Utility / Region**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	$ 50,211.0	$ 48,858.0	$ 49,656.5	$ 51,239.0
Vancouver Island	9,564.3	9,292.1	9,895.0	10,262.5
Whistler	278.0	269.3	236.2	244.2
Fort Nelson	165.2	165.8	172.4	178.0
Total Property Taxes	**$ 60,218.5**	**$ 58,585.2**	**$ 59,960.0**	**$ 61,923.7**

The Mainland, Whistler and Fort Nelson regions maintain Commission approved deferral account mechanisms to track variances between forecast and actual property tax expense. Please refer to Section 6.2 for a discussion of the Property Tax Variance Accounts. For Vancouver Island, the variances flow through the RSDA.

The following subsections provide details on the property tax forecasts for each Utility.

[100] Section 7.1 to 7.4, Schedule 25 & 26

5.6.2.1 Mainland Property Tax Expense

Table 5.6-2 below provides the property tax forecast for the Mainland.

Table 5.6-2: Forecast Mainland Property Tax Expense

($ thousands) Asset Type	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets	$ 17,486.0	$ 16,539.6	$ 17,889.3	$ 18,842.7
Transmission Assets	13,497.2	13,309.6	14,035.4	14,485.9
Gas Storage Assets	471.5	942.1	987.5	1,033.9
Manufactured Gas Assets	13.8	25.8	27.0	28.3
General Assets	2,479.2	2,681.9	2,804.4	2,935.3
Revenue and Other Taxes	16,263.2	15,359.0	13,912.9	13,912.9
Total Property Taxes	**$ 50,211.0**	**$ 48,858.0**	**$ 49,656.5**	**$ 51,239.0**

Mainland property taxes are forecast to be $1,353 thousand (2.8 percent) lower than originally approved for 2011. 2012 property taxes are forecast to increase by $798.5 thousand (1.6 percent) compared to projected 2011 and 2013 property taxes are forecast to increase by $1.58 million (3.2 percent) compared to forecast 2012 based on the following:

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1. Distribution Assets

   2011: 2011 Taxes are projected to be lower than 2011 Approved due to lower forecast tax rates.

   2012: Comparing the 2012 Forecast to 2011 projected property taxes, additions are expected to add $400 thousand in taxes, with the remaining $950 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

   2013: In 2013, additions are expected to add $400 thousand in taxes, with the remaining $554 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Transmission, Gas Storage, Manufactured Gas and General Assets

   For 2011 to 2013 taxes on transmission, gas storage, manufactured gas and general assets are forecast to increase as a result of inflationary pressures from materials and labour on legislated pipeline rates, in addition to increases in general and other tax rates.

3. Revenue and other taxes

   A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. For all municipalities except the City of Vancouver, FEI pays a tax of 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010. For the City of Vancouver, FEI pays 1.25 percent of revenues earned in the preceding year. For example, taxes payable to the City of Vancouver in 2012 will reflect revenues earned in 2011.

   2011 and 2012 taxes payable are based on actual reporting. 2012 taxes payable are forecast to decline by an average of 9.4 percent, while 2013 taxes are forecast to remain unchanged from 2012 levels.

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5.6.2.2 Vancouver Island Property Tax Forecast

Table 5.6-3 below provides the property tax forecast for Vancouver Island.

Table 5.6-3: Forecast Vancouver Island Property Tax Expense

($ thousands) Asset Type	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets	$ 4,700.7	$ 4,426.7	$ 4,715.6	$ 4,968.1
Transmission Assets	2,373.1	2,472.8	2,601.9	2,686.7
Gas Storage Assets	618.9	507.6	620.6	634.7
Manufactured Gas Assets	-	-	-	-
General Assets	170.4	152.4	359.1	375.1
Revenue and Other Taxes	1,701.3	1,732.6	1,597.9	1,597.9
Total Property Taxes	**$ 9,564.3**	**$ 9,292.1**	**$ 9,895.0**	**$ 10,262.5**

Vancouver Island property taxes are forecast to be $272.2 thousand (2.9 percent) lower than approved for 2011. 2012 property taxes are forecast to increase by $602.9 thousand (6.5 percent) compared to projected 2011 and 2013 property taxes are forecast to increase by $367.5 thousand (3.7 percent) compared to forecast 2012 based on the following:

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1. Distribution Assets

   2011: 2011 Taxes are expected to be lower than 2011 Approved due to lower forecast tax rates.

   2012: Comparing 2012 Forecast to 2011 projected property taxes, additions are expected to add $103 thousand in taxes, with the remaining $185.7 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2013: In 2013, additions are expected to add $105.2 thousand in taxes, with the remaining $147.3 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Transmission

2011 projected taxes are expected to be higher than originally forecast because of inflationary pressures from materials and labour on legislated pipeline rates. For 2012 to 2013, taxes on transmission assets are forecast to increase as a result of inflationary pressures from materials and labour on legislated pipeline rates, in addition to increases in general and other tax rates.

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3. Gas Storage

The projected 2011 taxes are expected to be lower than 2011 Approved due to lower expected tax rates.

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In 2012, completion of the Mt. Hayes LNG facility in 2011 will result in full taxation of this facility adding $99.3 thousand in taxes. Increases in tax rates results in an additional $13.7 thousand in taxes.

In 2013, taxes are expected to increase by $14.1 thousand due to general inflation on assessment values and tax rates.

4. General Assets

General assets are mainly comprised of office buildings. In 2011, taxes for general assets are projected to be lower than originally forecast as it was originally expected the Langford regional operations centre would become taxable to FEVI in 2011, however, the purchase is not expected to complete until April 2011.

For 2012, this property is forecast to be fully taxable resulting in increased property taxes of $182.6 thousand. General forecast property value increases and higher tax rates result in an additional $24.1 thousand in property taxes.

In 2013, taxes are forecast to increase by $16.0 thousand due to overall property value inflation and higher general and other tax rates.

5. Revenue and other taxes

A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. For all municipalities FEVI pays 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010.

2011 taxes payable are based on actual reporting. 2012 taxes payable used preliminary estimates of actual data, which indicated an average decrease of 7.8 percent in reported revenues. 2013 taxes are based on a zero increase on 2010 revenues.

5.6.2.3 Whistler Property Tax Forecast

Table 5.6-4 below provides the property tax forecast for Whistler.

Table 5.6-4: Forecast Whistler Property Tax Expense

($ thousands) Asset Type	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets	$ 118.2	$ 108.8	$ 115.9	$ 123.8
Transmission Assets	-	-	-	-
Gas Storage Assets	-	-	-	-
Manufactured Gas Assets	-	-	-	-
General Assets	-	-	-	-
Revenue and Other Taxes	159.8	160.5	120.3	120.3
Total Property Taxes	**$ 278.0**	**$ 269.3**	**$ 236.2**	**$ 244.2**

Whistler property taxes are forecast to be $8.7 thousand (3.2 percent) lower than originally approved for 2011. 2012 property taxes are forecast to decrease by $33.1 thousand (12.3 percent) when compared to projected 2011 and 2013 property taxes are forecast to increase by $8.0 thousand (3.4 percent) compared to forecast 2012 based on the following:

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1. Distribution Assets

2011: 2011 Taxes are expected to be lower than 2011 Approved due a successful appeal in 2011 resulting in lower assessment values.

2012: Comparing 2012 Forecast to 2011 projected property taxes, additions are expected to add $2.5 thousand in taxes, with the remaining $4.6 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2013: In 2013, additions are expected to add $2.6 thousand in taxes, with the remaining $5.3 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Revenue and Other taxes

   A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. Whistler revenues are calculated based on 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010.

   2011 and 2012 taxes payable are based on actual reporting. 2013 taxes are based on a zero increase to 2010 revenues.

5.6.2.4 Fort Nelson Property Tax Forecast

Table 5.6-5 below provides the property tax forecast for Fort Nelson.

Table 5.6-5: Forecast Fort Nelson Property Tax Expense

($ thousands) Asset Type	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets	$ 94.9	$ 92.1	$ 99.5	$ 104.4
Transmission Assets	0.3	0.3	1.3	1.3
Gas Storage Assets	-	-	-	-
Manufactured Gas Assets	-	-	-	-
General Assets	12.5	13.5	14.2	14.9
Revenue and Other Taxes	57.5	60.0	57.4	57.4
Total Property Taxes	**$ 165.2**	**$ 165.8**	**$ 172.4**	**$ 178.0**

Fort Nelson property taxes are forecast to be $0.6 thousand (1.1 percent) higher than originally approved for 2011. 2012 property taxes are forecast to increase by $6.5 thousand (3.9 percent) when compared to projected 2011 and 2013 property taxes are forecast to increase by $5.6 thousand (3.2 percent) when compared to forecast 2012 based on the following:

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1. Distribution Assets

   2011: 2011 Taxes are expected to be lower than 2011 Approved due lower forecast tax rates.

   2012: Comparing 2012 Forecast to 2011 projected property taxes, additions are expected to add $2.5 thousand in taxes, with the remaining $4.9 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2013: In 2013, additions are expected to add $2.5 thousand in taxes, with the remaining $2.4 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Transmission Assets

   The Muskwa River Crossing Project is forecast to add $1.0 thousand in 2012.

3. General Assets

   General assets are mainly comprised of the Fort Nelson office, taxes on which are forecast to increase by general inflation.

4. Revenue and Other Taxes

   A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. Fort Nelson revenues are calculated based on 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010.

   Revenues from gas consumed within Fort Nelson (Northern Rockies Regional Municipality[101]) are expected to increase in 2011 and decrease by 4.5 percent in 2012 based on actual reported 2010 revenues. For 2013, revenues are forecast to remain unchanged.

5.6.3 CARBON TAX

The Carbon Tax represents a cost to the Companies on their own consumption of fuel to operate compressors, line heaters, motor vehicles and space heating. The Carbon Tax rate applicable to natural gas effective July 1, 2011 is $1.24 per GJ, and will rise to $1.49 per GJ on July 1, 2012. There are no further announced increases beyond this date. The estimated costs to the FortisBC Energy Utilities with respect to Carbon Tax on own-use fuel are embedded in O&M and capital. If the Carbon Tax rate is adjusted during the period of the RRA from what is currently enacted, the impact will be assessed and reflected in the Tax Variance Deferral Accounts.

[101] Northern Rockies Regional Municipality was created with the amalgamation of The Town of Fort Nelson and the Northern Rockies Regional District on February 6, 2009

FEI does not have any long-term debt due for redemption in 2012 or 2013, but expects to issue $100 million in medium term note debentures in July of 2011 and has reflected this issue in its long term debt projection.

In 2013 FEVI has forecast a $15.5 million retirement of the Pacific Coast Energy Pipeline Agreement ("PCEPA") revolving credit facility, which matures in January 2013. The PCEPA facility is available solely for the purpose of funding prepayments of the Government of Canada and Government of BC contributions. The non-interest bearing contributions from the Federal and Provincial governments were in connection with the construction and operation of the Vancouver Island natural gas pipeline, of which $49.1 million is forecast to be outstanding at year-end 2011, drawn down to $25.0 million by year-end 2013.[102] These contributions are shown as CIAC. Any annual prepayments of the Government contributions are funded with debt and equity in the same proportion as the capital structure of Vancouver Island. The repayment of the PCEPA facility and also the refinancing of the 2013 contributions will be financed through short-term debt as the amounts come due, with a long-term debt issue planned for after 2013.

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FEW has not forecast any long-term debt issuances or redemptions in 2012 or 2013.

5.7.1.3 Forecast of Interest Rates for 2012 and 2013

The Companies use interest rate forecasts to estimate future interest expense. Forecasts of Prime rate and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for new issues of long-term debt. The forecasts are averages of projections made by leading economists at four Canadian Chartered banks. Credit spreads on new long-term debt are based on current indicative rates.

Short-term rates (i.e. Prime bank lending rate) are projected to increase in the coming months. Surveys of leading economists expect the Prime bank lending rate to remain on average at 3.63 percent for 2011, and then increase to 5.56 percent by 2013.[103] The Companies' short-term borrowing rate forecast for 2012 and 2013 is based on the historical short-term borrowing differential between the Prime bank lending rate and the rate issued under the commercial paper program at that time. The short-term interest rate forecasts for all Companies are shown in Table 5.7-1 and Table 5.7-2 below.

[102] Section 7.2, Schedule 84
[103] Economist reports are included in Appendix C-1

Table 5.7-1: Determination of Short-Term Interest Rates for 2012

2012 Interest Rate Forecast				
	Mainland	Vancouver Island	Whistler	Fort Nelson
Prime Rate	4.22%	4.22%	4.22%	4.22%
Short-Term Debt Rate Spread	-1.72%	-0.22%	-0.72%	-1.72%
Short-Term Debt Rate	2.50%	4.00%	3.50%	2.50%

Table 5.7-2: Determination of Short-Term Interest Rates for 2013

2013 Interest Rate Forecast				
	Mainland	Vancouver Island	Whistler	Fort Nelson
Prime Rate	5.28%	5.28%	5.28%	5.28%
Short-Term Debt Rate Spread	-1.78%	-0.28%	-0.78%	-1.78%
Short-Term Debt Rate	3.50%	5.00%	4.50%	3.50%

Due to the uncertainty associated with forecasting interest rates, the Mainland, Whistler and Fort Nelson utilities have an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances and variances in the timing of long-term debt issues, as compared to forecast.

5.7.1.4 Interest Expense Forecast

The interest expense forecast reflects the Utilities' existing and projected borrowing costs on long term debt and projected short-term debt.

The calculation for short-term interest expense is determined by applying the short-term debt rate to the short-term debt balance. Long-term debt interest expense is determined using the effective interest method. For each long-term debt issue, the effective rate (forecast effective rate if it is a new issue) is multiplied by the average balance of that long-term debt for the year. The long-term debt schedules for each company can be found in Sections 7.1 to 7.4, Schedule 82 to 84.

The following tables highlight long-term and short-term interest expense for 2012 and 2013.

Table 5.7-3: Forecast 2012 Interest Expense[104]

2012 Forecast, ($ thousands)					
Interest Expense	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Short Term	1,874	4,299	183	6	6,362
Long Term	108,114	20,950	1,022	290	130,376
Total Interest Expense	**109,988**	**25,249**	**1,205**	**296**	**136,738**

Table 5.7-4: Forecast 2013 Interest Expense[105]

2013 Forecast, ($ thousands)					
Interest Expense	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Short Term	3,855	6,971	216	14	11,056
Long Term	108,352	20,473	1,022	355	130,202
Total Interest Expense	**112,207**	**27,444**	**1,238**	**369**	**141,258**

5.7.2 ALLOWED CAPITAL STRUCTURE AND RETURN ON EQUITY

On December 16, 2009, the Commission released Order No. G-158-09 and its accompanying decision on "*Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Return on Equity and Capital Structure Application".* The decision established the deemed capital structure for each utility, discontinued the use of the automatic adjustment mechanism, and fixed an allowed return on equity for all three utilities. For purposes of determining the revenue requirements for 2012 and 2013, the 2012 and 2013 capital structure and return on equity for each of the Companies will remain as currently approved through BCUC Order No. G-158-09. Below, the Companies have set out the deemed capital structure and allowed ROE used in the calculation of the 2012 and 2013 revenue requirements, and explain their rationale for deferring a request for filing evidence on the equity component of capital structure for FEVI and FEW.

5.7.2.1 Background

The capital structure and return on common equity ("ROE") for FEU is established by the Commission for use in the calculation of rates. For many years, the Commission annually set the ROE for utilities in British Columbia based on the Benchmark ROE for FEI using a formula that ties the utilities' rates of return on equity to the forecast yield on long-term Canada (30

[104] Section 7.1 to 7.4, Schedule 80
[105] Section 7.1 to 7.4, Schedule 81

6 RATE BASE

The determination of rate base is a significant step in the calculation of the revenue requirement; it forms the basis for the earned return component of the cost of service. The rate base is comprised of:

- mid-year net plant in-service (gross plant in service, less contribution in aid of construction, less accumulated depreciation relating to both, and negative salvage), adjusted for the timing of completion of major capital projects;
- work-in-progress not attracting allowance for funds used during construction;
- the mid-year balance of unamortized deferral accounts (regulatory assets and liabilities);
- the thirteen-month average of cash working capital and other working capital;
- mid-year future income tax asset and offsetting liability; and
- in the case of the Mainland, the LILO benefit arising from LILO agreements with several Interior municipalities.

The following subsections will discuss in detail the various components of rate base, beginning with an overview of rate base and a summary by utility/region (Section 6.1) that is followed by discussions on capital expenditures (Section 6.2) and rate base deferral accounts (Section 6.3).

6.1 Rate Base Overview and Summary by Utility/Region

The 2012 and 2013 rate base amounts, as determined in Sections 7.1 to 7.4, Schedules 40 and 41 of this RRA, represent the average investment by the Companies in utility assets necessary to provide service to our customers. The table below sets out the forecast rate base for 2012 and 2013, for each FortisBC Energy Utility.

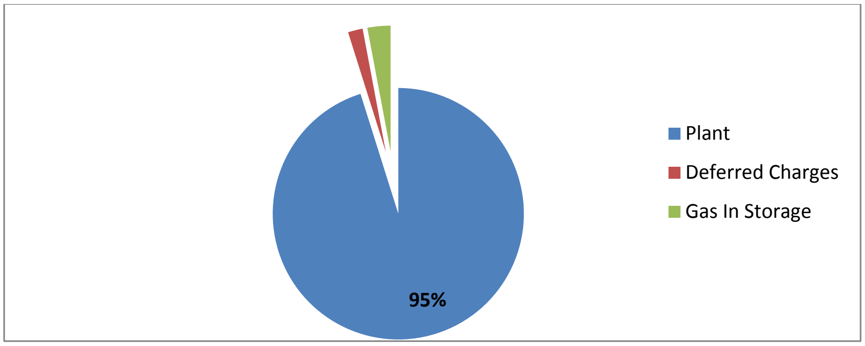
Table 6.1-1: Rate Base in 2012 and 2013 is Growing[109]

Utility/Region, ($ thousands)	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 2,629,185	$ 2,753,641	$ 2,810,535
Vancouver Island	728,993	788,329	815,707
Whistler	42,594	42,046	41,346
Fort Nelson	6,839	7,438	9,291
	$ 3,407,611	$ 3,591,454	$ 3,676,879

[109] Section 7.1 to 7.4, Schedules 40 and 41

The total FEU rate base of $3.6 billion is comprised largely of net gas plant in service as shown in Figure 6.1-2:

Figure 6.1-1: FEU Rate Base is Primarily Net Gas Plant in Service



The following subsections provide a discussion on the various components of rate base for each Utility.

6.1.1 MAINLAND RATE BASE SUMMARY

The table below sets out the Mainland rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

Table 6.1-2: Mainland Rate Base 2011 through 2013[110]

Mainland, $ thousands	Approved 2011	Forecast 2012	Forecast 2013
Mid Year Net Plant In Service	$ 2,494,713	$ 2,566,257	$ 2,645,300
Adjustment to 13-month average	-	42,214	-
Work in progress, no AFUDC	15,627	17,110	17,110
	2,510,340	2,625,581	2,662,410
Deferred Charges	6,770	31,583	49,909
Cash Working Capital	(6,534)	(3,112)	(2,256)
Gas In Storage Working Capital	114,804	97,294	97,242
Other Working Capital	5,287	3,611	4,380
Other	(1,482)	(1,316)	(1,150)
Utility Rate Base	$ 2,629,185	$ 2,753,641	$ 2,810,535

[110] Section 7.1, Schedules 40 and 41

The growth in rate base for the forecast period is largely attributable to investments in system sustainment and reliability and the addition of assets (both capital and deferral) related to the CCE Project being in service starting in 2012. Offsetting these increases are reductions in Gas In Storage due primarily to lower commodity rates. Driving the increase in the 2013 deferred charges is the growth in the balance of the EEC deferral account and the full amortization of credit balances in several of the Non-Controllable deferral accounts in 2012. Please refer to Section 6.3 for a discussion on the forecast deferred charges balances.

6.1.2 VANCOUVER ISLAND RATE BASE SUMMARY

The table below sets out the Vancouver Island rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

Table 6.1-3: Increase in Vancouver Island Rate Base is Driven by Mount Hayes LNG[111]

Vancouver Island, $ thousands	Approved 2011	Forecast 2012	Forecast 2013
Mid Year Net Plant In Service	$ 651,454	$ 774,088	$ 797,079
Adjustment to 13-month average	56,712	1,210	-
Work in progress, no AFUDC	3,608	2,285	2,285
	711,774	777,583	799,364
Deferred Charges	4,908	(621)	5,355
Cash Working Capital	134	325	552
Gas In Storage Working Capital	11,146	10,605	10,605
Other Working Capital	1,031	437	(169)
Other	-	-	-
Utility Rate Base	$ 728,993	$ 788,329	$ 815,707

The growth in the 2012 rate base is generally attributable to the full year impact of the Mount Hayes LNG Facility. Balances in the GCVA and EEC deferral accounts are the significant contributors to changes in the mid-year balance of deferred charges included in rate base. Please refer to Section 6.3 for a discussion on the forecast deferred charges balances.

6.1.3 WHISTLER RATE BASE SUMMARY

The table below sets out the Whistler rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

[111] Section 7.2, Schedules 40 and 41

Table 6.1-4: Amortization of the Pipeline Contribution Decreases Whistler's Rate Base[112]

Whistler, $ thousands	Approved 2011	Forecast 2012	Forecast 2013
Mid Year Net Plant In Service	$ 12,643	$ 13,746	$ 14,080
Adjustment to 13-month average	-	111	-
Work in progress, no AFUDC	63	23	23
	12,706	13,880	14,103
Deferred Charges	29,176	27,486	26,550
Cash Working Capital	31	47	58
Gas In Storage Working Capital	655	628	625
Other Working Capital	26	5	10
Other	-	-	-
Utility Rate Base	$ 42,594	$ 42,046	$ 41,346

The annual amortization of the Whistler Pipeline Contribution results in a slight decline to the Whistler rate base each year. As discussed in Section 6.3, the Whistler Pipeline Contribution has been decreased by approximately $2.5 million reflecting a reduction in the estimate of the final Pipeline costs; however, this reduction is offset by additions in 2012 and 2013 related to the CCE Project as well as other plant additions.

6.1.4 FORT NELSON RATE BASE SUMMARY

The table below sets out the Fort Nelson rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

[112] Section 7.3, Schedules 40 and 41

Table 6.1-5: Increases in Fort Nelson Rate Base Due to Muskwa River Crossing[113]

Fort Nelson, $ thousands	Approved 2011	Forecast 2012	Forecast 2013
Mid Year Net Plant In Service	$ 7,256	$ 7,416	$ 9,193
Adjustment to 13-month average	(666)	-	-
Work in progress, no AFUDC	38	-	-
	6,628	7,416	9,193
Deferred Charges	154	10	82
Cash Working Capital	54	8	12
Gas In Storage Working Capital	-	-	-
Other Working Capital	3	4	4
Other	-	-	-
Utility Rate Base	$ 6,839	$ 7,438	$ 9,291

The growth in the 2013 rate base is attributable to the full year impact of the Muskwa River Crossing Project. The projected in-service date of the assets related to the Project is June 2012 with total project costs currently estimated at $3.1 million (excluding AFUDC).

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6.1.5 NET PLANT IN SERVICE ("NPIS")

The mid-year NPIS balances reflect the necessary additions to ensure that the Utilities are able to meet the needs of our customers. The mid-year NPIS is the largest component of rate base and is the sum of the averages of the gross plant in-service (including intangible plant), CIAC, accumulated depreciation, and negative salvage.

6.1.5.1 Gross Plant in Service ("GPIS")

The ending GPIS balances are made up of opening GPIS plus plant additions, both regular and CPCNs, less retirements. Plant additions are comprised of capital expenditures plus overheads capitalized, plus AFUDC, and adjusted for opening and closing work-in-progress ("WIP"). Details of capital expenditures are discussed in Section 6.2. Retirements are forecast as a percentage of additions each year. The percentage used is based on a five year historical average for all classes except those subject to amortization accounting. For asset classes subject to amortization accounting, retirements are forecast based on the year that the asset becomes fully amortized.

The mid-year gross plant in service is as follows:

113 Section 7.4, Schedules 40 and 41

Table 6.1-6: Approved and Forecast Gross Plant in Service Balances

Utility/Region, $ thousands	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 3,495,886	$ 3,666,655	$ 3,848,489
Vancouver Island	1,155,525	1,290,412	1,331,130
Whistler	16,225	16,710	17,420
Fort Nelson	10,458	10,672	12,760
Total	$ 4,678,093	$ 4,984,448	$ 5,209,799

The forecast gross plant in service additions for the Utilities for 2012 and 2013 are as follows:

Table 6.1-7: Mainland Gross Plant in Service Additions[114]

Mainland, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$129,970	$127,010
Overhead Capitalized	32,226	33,754
AFUDC and WIP Adjustments	5,127	4,628
Subtotal: Regular Capital Additions	167,323	165,392
Special Projects & CPCN Additions	89,717	-
Total Plant Additions	$257,040	$165,392

Table 6.1-8: Vancouver Island Gross Plant in Service Additions[115]

Vancouver Island, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 29,950	$ 29,079
Overhead Capitalized	5,056	5,072
AFUDC and WIP Adjustments	138	146
Subtotal: Regular Capital Additions	35,145	34,298
Special Projects & CPCN Additions	21,973	-
Total Plant Additions	$ 57,118	$ 34,298

[114] Section 7.1, Schedule 42
[115] Section 7.2, Schedule 42

Table 6.1-9: Whistler Gross Plant in Service Additions[116]

Whistler, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 719	$ 480
Overhead Capitalized	127	128
AFUDC and WIP Adjustments	-	-
Subtotal: Regular Capital Additions	846	608
Special Projects & CPCN Additions	221	-
Total Plant Additions	$ 1,066	$ 608

Table 6.1-10: Fort Nelson Gross Plant in Service Additions[117]

Fort Nelson, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 3,275	$ 276
Overhead Capitalized	122	126
AFUDC and WIP Adjustments	389	-
Subtotal: Regular Capital Additions	3,786	401
Special Projects & CPCN Additions	-	-
Total Plant Additions	$ 3,786	$ 401

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

The AFUDC rate applied to work in progress is based on the Company's after tax weighted average cost of capital ("WACC").[118] The WACC for each Company is based on its current approved capital structure and is determined as follows:

Figure 6.1-2: After Tax Weighted Average Cost of Capital Formula

(ROE x Equity Thickness) + [(Long Term Debt Rate x Long Term Debt Thickness) + (Short Term Debt Rate x Short Term Debt Thickness)] x (1- Tax Rate)

The approved AFUDC Rates for 2011 and the forecast AFUDC rates for 2012 and 2013 are shown in Table 6.1-11.

116 Section 7.3, Schedule 42
117 Section 7.4, Schedule 42
118 The AFUDC rate also applies to non-rate base deferral accounts

Table 6.1-11: Forecast AFUDC Rates for 2012 and 2013

Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	6.83%	6.79%	6.79%
Vancouver Island	6.63%	6.40%	6.52%
Whistler	6.26%	6.15%	6.25%

The AFUDC charged to work in progress is calculated by multiplying the project costs by the company's AFUDC rate. Table 6.1-12 below shows the 2011 approved and 2012 and 2013 forecast AFUDC by utility.

Table 6.1-12: Approved and Forecast AFUDC

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	5,878	2,104	1,768
Vancouver Island	3,650	741	146
Whister			
Fort Nelson		89	
Total	**$ 9,528**	**$ 2,934**	**$ 1,914**

6.1.5.2 Contributions in Aid of Construction (CIAC)

Gross CIAC is composed of opening contributions, plus additions, and less the retirements throughout the year. The year-end CIAC amounts reflect forecast contributions associated with main extensions, excess service line charges, billable alterations, hazard mitigation work chargeable to customers, and system damage. The Utilities do not forecast retirements for CIAC, except for software tax savings which are retired based on the year that they become fully amortized and in the case of Vancouver Island, retirements related to the government loans. The CIAC in the Vancouver Island rate base includes government loan retirements of $20 million in 2012 and $4.1 million in 2013, bringing the outstanding balance of the government loans to $29.1 million at the end of 2012 and $25.0 million at the end of 2013. The closing balance of CIAC in Vancouver Island also includes the contribution from Whistler to Vancouver Island for the Whistler pipeline of $14.6 million. Forecast additions to CIAC are discussed in Section 6.2.6.

The year-end CIAC amounts are forecast as follows:

Table 6.1-13: The Year End Balance of CIAC Decreases Rate Base[119]

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ (194,753)	$ (183,107)	$ (189,803)
Vancouver Island	(276,176)	(254,306)	(250,614)
Whistler	(96)	(186)	(186)
Fort Nelson	(1,271)	(1,287)	(1,287)
Total	**$ (472,296)**	**$ (438,886)**	**$ (441,890)**

6.1.5.3 Accumulated Depreciation

The rate base of the Utilities includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation and amortization expense, and decreased through retirements. A discussion on the depreciation policies for the Utilities is included in Section 5.4. In addition, the accumulated depreciation balances reflect depreciation expense calculated using the depreciation rates as recommended by the updated Depreciation Study and the opening 2012 accumulated depreciation balances have been adjusted to reflect the transfer of estimated negative salvage opening balances to the negative salvage provision.

The mid-year accumulated depreciation is as follows:

Table 6.1-14: Forecast Accumulated Depreciation Reflects Updated Depreciation Study and Negative Salvage Transfers[120]

Utility/Region, $ thousands	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ (860,508)	$ (967,356)	$ (1,061,270)
Vancouver Island	(285,125)	(302,626)	(332,828)
Whistler	(3,496)	(2,761)	(3,067)
Fort Nelson	(2,486)	(2,508)	(2,853)
Total	$ (1,151,615)	$ (1,275,250)	$ (1,400,017)

6.1.5.4 Negative Salvage

As discussed in Section 5.4.3, the rate base of the Utilities includes both an opening and closing balance for negative salvage. The continuity of negative salvage (see Sections 7.1 to 7.4, Schedule 61 and 62) is described further below.

119 Section 7.1 to 7.4, Schedules 63-65
120 Section 7.1 to 7.4, Schedules 54-60

OPENING BALANCE

The opening balance is transferred from accumulated depreciation and determined by calculating the December 31, 2009 negative salvage provision as follows:

1. Increases in provision equal to the negative salvage component of depreciation rates multiplied by the applicable year's opening gross plant balance for those asset classes and years this treatment was approved (asset classes 474 and 478 in FEI starting in 2004; asset classes 462, 463, 465, 466, 467, 472, 473, 474, 475, 477, 478, 482, 484, 485 in FEVI starting in 2003);
2. Decreases in provision equal to the actual removal costs less salvage incurred in each of those years.

ADDITIONS

Additions represent the provisions for negative salvage as calculated using the estimated negative salvage rates provided in Table 5.4-4 and determined through the Depreciation Study included as Appendix E-1. The provision is included as a line item on the depreciation schedule and is added back for purposes of calculating income tax expense (Sections 7.1 to 7.4, Schedules 33 to 35).

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COSTS INCURRED

These are the estimates of actual costs to be incurred for removal. These are the costs deducted in calculating income tax expense.[121]

Retirement costs are incurred in all major gas asset categories including mains, services, meters and stations. The following table summarizes historical and forecast expenditures required to support ongoing recurring retirement work in these gas asset categories.

Table 6.1-15: Approved, Actual and Forecast Retirement Expenditures

Utility/Region, ($ thousands)	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 11,290	$ 13,832	$ 12,932
Vancouver Island	344	632	648
Whistler	5	6	6
Fort Nelson	-	-	-
	$ 11,639	$ 14,470	$ 13,586

The types of retirement activities that occur are described separately below:

[121] Section 7.1 to 7.4, Schedules 33 to 35

CLOSING BALANCE

Calculated as the opening balance plus additions less costs incurred. The closing balance is deducted from rate base on Sections 7.1 to 7.4, Schedules 40 and 41.

As discussed in Section 5.4, the FortisBC Energy Utilities believe that the proposed treatment is in the best long-term interests of customers and is the most appropriate for rate making purposes.

The mid-year negative salvage included in rate base for 2012 and 2013 is as follows:

Table 6.1-16: Mid-Year Balance of Negative Salvage[122]

Utility/Region, $ thousands	Forecast 2012	Forecast 2013
Mainland	$ (5,609)	$ (8,745)
Vancouver Island	(10,835)	(14,176)
Whistler	(37)	(112)
Fort Nelson	-	-
Total	$ (16,481)	$ (23,033)

6.1.6 13-MONTH ADJUSTMENT

Since the NPIS is calculated on a mid-year basis (beginning plus ending divided by two), for large capital projects, the rate base is adjusted to reflect the timing of when these projects actually go into rate base. In 2012, a 13-month adjustment has been applied to Mainland, Vancouver Island and Whistler to include the assets associated with the CCE Project as of January, 2012. For the Mainland, the 13-month adjustment also accounts for the Tilbury Land purchase which enters rate base January 1, 2012, and Kootenay River Crossing Project. For Vancouver Island, the 13-month adjustment also accounts for the Victoria Regional Office CPCN in-service as of October 2012. The Companies have not forecast any 13-month adjustments in 2013.

6.1.7 WORK IN PROGRESS INCLUDED IN RATE BASE

Consistent with past practice, Work in Progress included in rate base represents construction work in progress for projects that are shorter than three months in duration and less than $50 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project. The Work in Progress (not attracting AFUDC) included in Rate Base has been forecast at the ending 2010 balance for both 2012 and 2013.

[122] Section 7.1 to 7.4, Schedules 61 and 62

Table 6.2-3: Approved, Actual and Forecast Whistler Capital Expenditures[126]

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	27	44	27	41	41	42
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	10	45	-	-	-	-
Distribution Mains and Service Renewals and Alterations	82	27	84	94	88	81
	120	**116**	**111**	**134**	**129**	**123**
Growth Capital						
New Customer Mains	51	219	35	218	223	227
New Customer Services	97	122	68	48	52	53
New Customer Meters	14	3	9	4	5	5
	163	**344**	**112**	**270**	**279**	**285**
Other						
Equipment	18	5	17	17	20	60
Facilities	53	15	25	25	290	13
IT	-	-	-	-	-	-
	71	**20**	**42**	**42**	**310**	**73**
Subtotal	**353**	**480**	**265**	**446**	**718**	**481**
Contributions in Aid of Construction						
	-	**(5)**	**-**	**-**	**-**	**-**
Total Regular Capital	**353**	**475**	**265**	**446**	**718**	**481**

126 Section 7.3, Schedule 42

Table 6.2-4: Approved, Actual and Forecast Fort Nelson Capital Expenditures[127]

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	3	3	2	2	2	2
Transmission System Reinforcements / Integrity and Reliability	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliability	729	325	2,711	95	3,006	160
Distribution Mains and Service Renewals and Alterations	69	17	63	63	63	33
	801	**345**	**2,776**	**160**	**3,071**	**195**
Growth Capital						
New Customer Mains	11	23	11	11	12	12
New Customer Services	22	32	13	48	47	53
New Customer Meters	4	10	5	6	6	6
	37	**65**	**29**	**65**	**65**	**71**
Other						
Equipment	-	-	8	8	10	10
Facilities	-	-	-	-	129	-
IT	-	-	-	-	-	-
	-	**-**	**8**	**8**	**139**	**10**
Contributions in Aid of Construction						
	-	**-**	**-**	**-**	**-**	**-**
Total Regular Capital	**838**	**410**	**2,813**	**233**	**3,275**	**276**

A discussion of each of the Sustainment Capital, Growth Capital, Equipment and Facilities, IT, and CIAC categories follows. The FEU have also provided a discussion of both current and forecast CPCN projects that are not included in the table above, but that enter rate base in the year that they go into service.

For historical information for each of the Companies please refer to Appendix D.

6.2.2 SUSTAINMENT CAPITAL EXPENDITURES

6.2.2.1 Overview of Sustainment Capital

The expenditures within sustainment capital include gas system improvements to ensure adequate capacity to the transmission and distribution system in order to meet forecast load and to ensure the safety, reliability and integrity of the system. These expenditures mitigate the risk of loss from system outages and business interruptions.

[127] Section 7.4, Schedule 42

6.2-5 below. The forecast for 2012 and 2013 is based on identifiable projects and represents a prudent and reasonable level of spending to provide reliable service.

Table 6.2-5: Approved, Actual and Forecast Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
System Integrity & Reliability Capital						
Meter Recalls/Exchanges	19,700	20,307	20,580	23,055	21,925	22,566
Transmission System Reinforcements / Integrity and Reliabililty	14,591	13,607	16,531	22,463	28,448	30,714
Distribution System Reinforcements / Integrity and Reliabililty	10,159	6,559	11,276	10,771	12,861	8,705
Distribution Mains and Service Renewals and Alterations	11,212	12,542	10,957	18,199	21,757	27,605
	55,662	**53,015**	**59,344**	**74,488**	**84,990**	**89,590**

In this Application, FEU is seeking approval for 2012 and 2013 sustainment capital budgets for distribution and transmission assets. FEU has forecast $85.0 million in 2012 and $89.6 million in 2013 for Sustainment Capital expenditures. This represents incremental spending of $25.6 million and $30.2 million in 2012 and 2013 respectively over 2011 approved amounts for the same purposes. The project descriptions for the 2012 and 2013 projects are provided in the sections that follow. This two year sustainment spending includes:

- Expenditures for meter recalls and meter exchange programs;
- System reinforcements to the distribution and transmission systems to maintain capacity to meet existing customer demand and forecast load;
- Replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and
- Expenditures for main and service alterations and renewals.

The following sections describe the Sustainment Capital expenditures for each of the four utilities – Mainland, Vancouver Island, Whistler, and Fort Nelson.

6.2.2.2 Mainland Sustainment Capital Overview

The 2010 through 2013 Mainland Sustainment Capital is shown in the following table. Overall, Sustainment Capital in the Mainland utility is forecast to grow to $65.5 million in 2012 (increase of $21.7 million or almost 50 percent from 2011 Approved). The 2013 forecast is $75.1 million (an increase of $9.6 million or 15 percent from 2012 Forecast).

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Table 6.2-6: Approved, Actual and Forecast Mainland Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
System Integrity & Reliability Capital						
Meter Recalls/Exchanges	18,178	19,126	19,055	21,825	20,668	21,272
Transmission System Reinforcements / Integrity and Reliabililty	9,546	9,771	8,663	14,595	20,350	24,386
Distribution System Reinforcements / Integrity and Reliabililty	7,900	5,198	6,250	8,361	7,170	7,610
Distribution Mains and Service Renewals and Alterations	10,060	11,342	9,810	16,716	17,330	21,845
	45,684	**45,437**	**43,778**	**61,497**	**65,517**	**75,114**

Each of the four categories is discussed further below.

6.2.2.3 Meter Recalls and Exchanges – Mainland

This section contains a discussion of all meter capital, including both the recalls and exchanges included in Sustainment Capital, and the new meters included in Growth Capital. Similarly, the discussion of meter expenditures for Vancouver Island, Whistler and Fort Nelson below also includes both sustainment and growth meter expenditures.

The three main considerations in understanding the forecast meter expenditure level are:

1. the level of activity (meters purchased and installed or exchanged);
2. the unit cost to purchase, fabricate and install the meter (dollars per meter); and
3. other miscellaneous meter and regulator programs.

A summary of 2011 Meters (New and Replacement) projections as well as 2012-2013 forecast activities, unit costs, and expenditures follows in Table 6.2-7 below. The level of activities combined with the unit cost form the basis for the total expenditures.

Table 6.2-7: Approved, Actual and Forecast Mainland Meters Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities						
Meters- Exchanges	60,255	61,540	60,175	61,853	62,350	62,300
Meters- New	5,952	6,928	6,166	6,314	6,656	6,923
Unit Costs ($/meter)						
Meters	$ 267	$ 274	$ 280	$ 280	$ 295	$ 304
Expenditures ($000's)						
Meters - Exchange	$ 16,079	$ 16,873	$ 16,861	$ 17,331	$ 18,408	$ 18,945
Meters - Other	$ 2,099	$ 2,253	$ 2,194	$ 4,494	$ 2,260	$ 2,328
Total Sustainment	$ 18,178	$ 19,126	$ 19,055	$ 21,825	$ 20,668	$ 21,273
Meters - New	$ 1,588	$ 1,905	$ 1,728	$ 1,769	$ 1,965	$ 2,105

METERS ACTIVITY LEVELS

The forecast level of meter activity is derived from the sum of the customer additions and the meter exchange forecasts. The meter forecast for new customers is derived directly from the forecast of customer additions using a one to one ratio. The forecast level of meter exchange activity to service existing customers is driven by life expectancy of meters and the total size of the meter population.

In the past few years, there were two specific drivers that significantly influenced the meter recall schedule. Prior to 2006, we managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the Company's own internal analysis, provided us with the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed the Mainland to temporarily reduce the number of meter recalls from between 40,000 to 50,000 meter recalls annually to a range between 25,000 to 35,000 recalls annually over the period 2006 - 2008. The reduction in the number of recalls brought the demographics of the meter fleet in line with a 20 year life expectancy, which provide customers with the cost benefits of previous investments in the fleet.

Forecast meter exchanges for 2012 and 2013 of approximately 62,000 per year are consistent with recent activity levels observed. Of the 62,000 forecast per year, approximately 58,000 are for the residential meter recalls program as well as unscheduled residential meter exchanges. The remaining units (approximately 4,300) are identified for the industrial meter exchange program (seven year exchange frequency) as well as unscheduled industrial meter exchanges.

We believe the established meter recall frequencies reflect the long term objectives of the fleet management program and will ensure our customers will continue to receive service that is both cost effective and reliable.

METERS UNIT COSTS

Aggregate or blended meter unit cost, which is the second consideration in establishing the forecast expenditure requirement for meters, is influenced by the type, size, and design of the meter, installation, fabrication and exchange conditions and the timing of bulk meter purchases and meter/regulator upgrade activity. A blended unit cost of all customer types is used for meter exchanges and installs. Meter unit costs typically range from $75 to $10,000 depending on customer requirements. In 2010, the blended meter unit cost consists of 35 percent labour and 65 percent material costs. Unit costs for meters for 2012 and 2013 are based on 2010 actuals and 2011 forecast inflation on labour and materials of 3 percent per annum. Also included in the 2012 unit cost increase is an incremental $6 per meter to reflect additional funding required for customer meter set upgrades and alterations. These upgrades are primarily on industrial/commercial meters to address obsolescent components and to facilitate field maintenance (i.e. the installation of a by-pass mechanism to eliminate a customer shutdown during routine meter maintenance).

METERS EXPENDITURES

In Table 6.2-7 above, the Exchange Meters expenditures forecast for 2012 and 2013 is $18.4 and $18.9 million respectively. Meters expenditures are variable and rise and fall with meter exchange activity levels. The regulators required for replacement activities are included in the "Meters-Other" category. In 2012 and 2013, $2.3 million is required for a continuation of the annual regulator ever-greening requirement. This is a program started in 2003 in Mainland to replace regulators at the same time as meters were replaced at the customer premise. The forecast in meter exchange activity levels together with the regulator replacement program is reflected in the aggregate expenditure requested.

6.2.2.4 Transmission System Reinforcement, Integrity & Reliability Capital – Mainland

These Transmission-related capital expenditures include system capacity improvements to meet existing customer demand and forecast load, and expenditures related to ensuring safety, reliability and integrity of the transmission system, as well as to minimize impact to the environment.

As shown in Table 6.2-6 above, the 2010 approved expenditure for the Mainland was approximately $9.6 million while the actual expenditure was approximately $9.8 million, a difference of 2 percent. It is expected that 2011 expenditures will be approximately $14.6 million. This is required to maintain capacity and upgrades to ensure safety, integrity and reliability. Included in the $14.6 million is $2 million for an initiative to reinforce the ground conditions or the FEI pipelines located at Burns Bog, improving the pipelines' system reliability and integrity. The forecasts for Mainland Transmission expenditures in

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A summary of 2011 Meters (New and Replacement) projections as well as 2012-2013 forecast activities, unit costs, and expenditures follows in Table 6.2-9 below. The level of activities combined with the unit cost form the basis for the total expenditures.

Table 6.2-9: Approved, Actual and Forecast Vancouver Island Meters Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities						
Meters- Exchanges	6,410	6,155	6,250	6,250	6,210	6,210
Meters- New	2,320	2,432	2,430	2,422	2,557	2,658
Unit Costs ($/meter)						
Meters	$ 233	$ 177	$ 239	$ 182	$ 188	$ 193
Expenditures ($000's)						
Meters - Exchange	$ 1,492	$ 1,134	$ 1,496	$ 1,188	$ 1,215	$ 1,250
Meters - New	$ 540	$ 430	$ 582	$ 441	$ 480	$ 513

METERS ACTIVITY LEVELS

As with the Mainland, the forecast level of meter activity for Vancouver Island is derived from the sum of the customer additions and the meter exchange forecasts. The meter forecast for new customers is derived directly from the forecast of customer additions using a one to one ratio. The forecast level of meter exchange activity to service existing customers is driven by life expectancy of meters and the total size of the meter population.

The meter exchange program on Vancouver Island is managed centrally through the Mainland Measurement department. Prior to being centralized, the meter exchange program was a "just in time" program where meter exchange levels were established based on original install dates and estimated life expectancy. Consistent with the program established for the Mainland, Vancouver Island will be exchanging the meter fleet in line with 20 year life expectancy on residential meters. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the Company's own internal analysis, has provided confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. The 20 year life span is the financially optimal target, balancing the risk (cost) of unscheduled failure with the replacement cost. An unscheduled failure is generally disruptive to the customer and more costly to execute in the field as compared to a scheduled replacement which can be completed at both the customer's and Company's convenience.

The early 1990s was a period of high customer (meter) growth for Vancouver Island and meters installed during this period are coming due for exchange. It is no longer viable to maintain lower exchange levels as the result of an aging meter fleet and anticipated early failures for some

6.2.2.13 Meter Recalls and Exchanges - Whistler

Meter activity levels are based on meters required to service new customers as well as meters exchanged for existing customers. The meters related to new customers are driven by the number of customer additions and the meters required for exchange activities are driven by Measurement Canada standards and the in-house program established to meet these standards. Meter unit cost is a blended amount of residential, commercial and industrial meters and forecast amounts for 2012 and 2013 reflect the most recent actual experience of 2010 with natural gas meters. Forecast meter expenditures for 2012-2013 are similar to 2010 actuals. The majority of these meter costs are related to the number of meter exchanges which are unchanged from previous years.

6.2.2.14 Distribution System Reinforcement, Integrity & Reliability Capital – Whistler

Whistler has limited facilities that fall within the scope of this category and thus on occasion there will not be a need for capital expenditure. This is the case for the 2011 through 2013 period.

The 2010 approved expenditure in Whistler was $10 thousand while the actual expenditure was $45 thousand. The expenditure was to address the replacement of valves at the Whistler District Station as they were found to leak gas when they were closed

6.2.2.15 Distribution Mains, Service Renewals and Alterations Capital – Whistler

In 2010 the actual expenditure was $55 thousand less than expected due to an anticipated main relocation within the village not materializing. There is no unusual activity anticipated within the Whistler system during 2012 or 2013. The forecast expenditures are required to address concerns regarding relocations of mains and services and hazards as they are found.

6.2.2.16 Fort Nelson Sustainment Capital Overview

The 2010 through 2013 Fort Nelson Sustainment Capital is shown in the following table. Overall, Sustainment Capital in Fort Nelson is forecast to return to normal levels after the completion of the Muskwa River crossing project in 2012.

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Table 6.2-11: Approved, Actual and Forecast Fort Nelson Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	3	3	2	2	2	2
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliability	729	325	2,711	95	3,006	160
Distribution Mains and Service Renewals and Alterations	69	17	63	63	63	33
	801	**345**	**2,776**	**160**	**3,071**	**195**

6.2.2.17 Meter Recalls and Exchanges – Fort Nelson

Forecast meter expenditures are required for new and replacement activities. There is minimal activity expected in 2011, and 2012 and 2013 forecasts are based on 2011 projections.

6.2.2.18 Distribution System Reinforcement, Integrity & Reliability Capital – Fort Nelson

Natural Gas service to the Fort Nelson area is provided by a single 114mm transmission pressure pipeline that crosses the Muskwa River on the southeast side of the town. This pipeline has become exposed and is now at risk of damage from river action. Expenditures are required to replace the pipeline crossing. As approved by the Commission in Order No. G-27-11, a river crossing replacement utilizing the adjacent highway bridge is projected to be the most cost-effective strategy. Total project costs for this option are currently estimated at $3.1 million (excluding AFUDC). Of this total, approximately $3.0 million will be added to rate base in late 2012, with the remainder being added in 2013.

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6.2.2.19 Distribution Mains, Service Renewals and Alterations Capital – Fort Nelson

Deleted: Capital expenditures in 2012 and 2013 are much lower than that of 2011 due to a return to more a typical capital expenditure period once the Muskwa River concern is addressed. However they are higher than the years prior to 2010 and 2011. The increase is primarily due to expenditures required for the replacement of existing equipment due to obsolescence and to address anticipated customer growth.¶

These expenditures primarily consist of replacement of intermediate or distribution pressure mains and services either to address integrity and reliability concerns identified by the Company or to address location concerns raised by others.

In 2010 the actual expenditures were $17 thousand compared to a budget of $69 thousand. The lower expenditure was due to a decision by the City of Fort Nelson to convert its pump station heating system to electricity rather than continue to use natural gas. This cancelled a planned $20 thousand upgrade to the local station. As well, we were not able to implement a $30 thousand program to remove culverts and valves that are no longer needed and pose a public

Meter and regulator expenditures consist of new meters and regulators to serve new customers. The two main considerations in understanding the forecast meter expenditure level are: (1) the level of activity (meters purchased and installed); and (2) the unit cost to purchase, fabricate and install the meter (dollars per meter). Growth meter expenditures have been discussed above in the sustainment capital section.

Biomethane and NGV expenditures are a new category of products offered by FEU and discussed in more detail in Appendix J and Appendix I respectively.

Below in Table 6.2-12 is a summary of the approved, actual, projected, and forecast Growth Capital expenditures for the combined FortisBC Energy Utilities.

Table 6.2-12: Approved, Actual and Forecast Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mains, Services & Meters Capital						
New Customer Mains	11,595	6,616	12,318	8,489	9,120	9,664
New Customer Services	20,781	19,337	22,480	15,725	17,077	18,292
New Customer Meters	2,147	2,348	2,323	2,221	2,455	2,630
Biomethane/NGV				7,440	3,078	3,578
	34,523	**28,301**	**37,122**	**33,875**	**31,730**	**34,163**

The following sections describe the Growth Capital expenditures for each of the four utilities – Mainland, Vancouver Island, Whistler, and Fort Nelson.

6.2.3.1 Mainland Growth Capital Overview

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for the Mainland are summarized in Table 6.2-13 below.

Table 6.2-13: Approved, Actual and Forecast Mainland Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mains, Services & Meters Capital						
New Customer Mains	8,807	4,538	9,306	5,698	6,127	6,500
New Customer Services	14,722	13,874	15,940	11,098	12,050	12,910
New Customer Meters	1,588	1,905	1,728	1,769	1,965	2,105
Biomethane/NGV				7,440	3,078	3,578
	25,117	**20,317**	**26,974**	**26,005**	**23,220**	**25,093**

6.2.3.2 Mains - Mainland

The drivers of the mains capital additions - forecast mains activity and unit costs - are summarized in Table 6.2-14 below.

Table 6.2-14: Approved, Actual and Forecast Mainland Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	112,136	81,259	116,166	100,031	105,450	109,680
Unit Costs ($/meter)	$ 79	$ 56	$ 80	$ 57	$ 58	$ 59
Expenditures ($000's)	$ 8,807	$ 4,538	$ 9,306	$ 5,698	$ 6,127	$ 6,500

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are each described in the following sections.

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year (2008-2010) historical ratio of 0.72 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2008-2010) historical ratio of 13.7 metres of new Main per new Service addition. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

The actual mains activity levels in 2010 were considerably lower than the approved levels largely due to the downturn in the economy in late 2008, a buildup of new mains infrastructure in 2005-2008, the beginning of a period of lower new subdivision activity in 2009 and decreases in housing starts in 2009. Typically, a new main takes up to five years to be fully utilized with service attachments prior to additional main extensions being required. Mains activity levels peaked in 2008 at 200,167 metres which equated to 19 metres of new main per service installed. The comparative ratio in 2010 was approximately 9 metres of new main per service installed reflecting the absence of developers seeking main extensions for new housing developments.

Projected new mains activity levels for 2011 are 100,724 metres based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new mains activity has been forecast at 105,395 and 109,623 metres, respectively.

Table 6.2-15: Approved, Actual and Forecast Mainland Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	5,952	6,928	6,166	6,314	6,656	6,923
Gross Customer Additions	9,336	9,587	9,672	10,124	10,672	11,100
Ratio of Service Additions to Gross Customer Additions	0.78	0.73	0.78	0.72	0.72	0.72
Activites (riser or services)	7,303	9,382	7,566	7,286	7,681	7,989
Unit Costs ($ per service - riser)	$ 2,016	$ 1,479	$ 2,107	$ 1,523	$ 1,569	$ 1,616
Expenditures ($000's)	$ 14,722	$ 13,874	$ 15,940	$ 11,098	$ 12,050	$ 12,910

SERVICES ACTIVITY LEVELS

The 2012 and 2013 forecast level of services activity is derived directly from the gross customer additions forecast, as discussed in Section 4. Using the three year historical average (2008-2010), the ratio of Service Additions to Gross Customer Additions is 0.72. A three year historical average ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected service additions activity levels for 2011 are 7,337 services and are based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new service activity has been forecast at 7,677 and 7,985 services, respectively.

SERVICES UNIT COSTS

Aggregate (blended) service unit cost, which is the second consideration in establishing the forecast expenditure requirement for new services, is calculated by taking all services costs (including service header main) and dividing by the number of risers (services) installed.

The 2010 actual and 2011 projected blended service unit cost was lower than the approved unit costs in the 2010-2011 RRA which were based on 2009 year-end projections of $2,000 per service which in turn were based on Jan-May 2009 actuals which reflected a significant downturn in the economy and shifting of services work from contractors to the company workforce. The 2009 end of year actual unit cost of $1,769 reflected a recovery in activities in the latter half of 2009 and an improvement in unit costs.

The forecast unit costs for 2012 and 2013 reflect the most recent actual aggregate unit cost experience of 2010 and the 2011 forecast. Activity levels have risen from the lows of 2008 and 2009 and aggregate unit costs are at the lowest levels seen since 2006. The 2010 unit cost of $1,479 was lower than the average 2008-2009 services unit cost of $1,709. Unit costs in 2010 were driven down by changes in the workforce (utility versus contractors), optimal crew sizing, increased activity levels, strengthening of the estimation process, elimination of higher priced secondary contractor, change in the mix of services, changes in the geographical mix of the services and exclusion of training costs in the labour rates. In 2010, contractors completed 36 percent of this work versus 32 percent in 2009. The 2008-2009 unit costs reflected the addition of apprentices to crews to train for replacement of retiring employees, the downturn in the economy in late 2008, lower services activities in 2009, changes in the geographical mix of these services and changes in the mix of these service products. Forecast unit costs are based on 2011 projections and reflect inflationary increases for both Mainland and Contractor workforces and equipment. The inflationary increases projected are 3 percent for 2012 and 3 percent for 2013.

Services Expenditures

The 2010 actuals and 2011 projected expenditures are lower than the 2010-2011 approved amounts due primarily to considerably lower unit costs driven by the factors cited in the Services Unit Costs section above. The lower services expenditures related to unit cost reductions were partially offset by increased service expenditures due to the higher number of services installed over approved levels.

Service expenditures for 2012 and 2013 are forecast at $12.1 and $12.9 million, respectively. Total services expenditures are largely variable and rise and fall with activity levels. The forecast activity levels, together with unit cost history adjusted for inflation form the basis for the aggregate expenditure requested. We believe these expenditures are prudent and reasonable in providing service products including service header mains to service new customers.

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6.2.3.4 New Meters – Mainland

The discussion of new meter expenditures is included in Section 6.2.2.3.

In Table 6.2-13 above, the New Meters expenditures forecast for 2012 and 2013 is $2.0 million and $2.1 million respectively. Meters expenditures are variable and rise and fall with customer additions activity levels.

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6.2.3.5 Biomethane/NGV - Mainland

Biomethane

Capital invested in interconnection facilities and upgrader equipment for Biomethane projects during the test period is forecast to be $3.1 million and $3.6 million in 2012 and 2013 respectively. Further detail on this capital investment is provided in Appendix J.

NGV

There are no capital expenditures forecast for NGV fueling assets in either 2012 or 2013.

Deleted: Capital invested in NGV fueling assets, subject to approval of the NGV Application presently before the Commission, is forecast to be $4 million in 2012 and $3.8 million in 2013. These projects will be accompanied by contracts that provide for their forecast incremental costs of service to be recovered through dedicated take-or-pay incremental revenues from the incremental NGV fueling customers. Further detail on this capital investment is provided in Appendix I.

6.2.3.6 Vancouver Island Growth Capital Overview

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for Vancouver Island are summarized in Table 6.2-16 below.

Table 6.2-16: Approved, Actual and Forecast Vancouver Island Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mains, Services & Meters Capital						
New Customer Mains	2,725	1,836	2,966	2,562	2,758	2,925
New Customer Services	5,940	5,309	6,459	4,531	4,927	5,276
New Customer Meters	540	430	582	441	480	513
	9,206	**7,575**	**10,006**	**7,534**	**8,165**	**8,714**

6.2.3.7 Mains – Vancouver Island

Forecast new mains activity, together with unit costs and capital expenditure levels are summarized in Table 6.2-17 below.

Table 6.2-17: Approved, Actual and Forecast Vancouver Island Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	30,116	18,282	31,610	25,008	26,402	27,445
Unit Costs ($/meter)	$ 90	$ 100	$ 94	$ 102	$ 104	$ 107
Expenditures ($000's)	$ 2,725	$ 1,836	$ 2,966	$ 2,562	$ 2,758	$ 2,925

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are described in the following three sections.

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year

The new mains expenditures forecasts for 2012 and 2013 are $2.8 million and $2.9 million respectively. Total new mains expenditures are largely variable and rise and fall with activity levels. The forecast activity levels of 26,393 meters in 2012 and 27,415 meters in 2013 are reflected in the aggregate expenditure requested. Experience with unit costs in 2010 with the current install contractor who completed 80 percent of this work, form the basis for the forecast unit costs. The forecast unit costs when applied to the forecast activity level drive the overall new mains expenditure requirement. We believe these expenditures are prudent and reasonable in providing for distribution main extensions to serve new customers.

6.2.3.8 Services – Vancouver Island

Forecast services together with unit costs and capital expenditure levels are summarized in Table 6.2-18 and discussed in the sections that follow.

Table 6.2-18: Approved, Actual and Forecast Vancouver Island Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	2,320	2,432	2,430	2,422	2,557	2,658
Gross Customer Additions	2,460	2,940	2,582	2,572	2,715	2,823
Ratio of Service Additions to Gross Customer Additions	0.78	0.85	0.78	0.72	0.72	0.72
Activites (riser or services)	1,922	2,501	2,017	2,073	2,188	2,274
Unit Costs ($ per service - riser)	$ 3,091	$ 2,123	$ 3,202	$ 2,186	$ 2,252	$ 2,320
Expenditures ($000's)	$ 5,940	$ 5,309	$ 6,459	$ 4,531	$ 4,927	$ 5,276

SERVICES ACTIVITY LEVELS

The 2012 and 2013 forecast level of services activity is derived directly from the gross customer additions forecast, as discussed in Section 4. Using the current three year historical average (2008-2010), the ratio of Service Additions to Gross Customer Additions calculated is 0.81. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected service additions activity levels for 2011 are 2,066 services and are based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new service activity has been forecast at 2,187 and 2,272 services, respectively.

SERVICES UNIT COSTS

Aggregate (blended) service unit cost, which is the second consideration in establishing the forecast expenditure requirement for new services, is calculated by taking all services costs (including service header main) and dividing by the number of risers (services) installed.

$37.9 million for 2013 represent the level of this type of investment required to provide safe, reliable and efficient service to new and existing customers of the FortisBC Energy Utilities.

6.2.4 FACILITIES AND EQUIPMENT CAPITAL

Facilities and Equipment Capital expenditures include the acquisition or leasing of land, station buildings, facilities equipment, telecommunications infrastructure, specialized tools and equipment, and radio system upgrades. Technological improvements tend to drive changes in tools, equipment, radios and furniture.

6.2.4.1 Facilities and Equipment Capital – Mainland

The approved, actual, projected, and forecast capital expenditures for the Mainland Facilities and Equipment are summarized in Table 6.2-21 below.

Table 6.2-21: Approved, Actual and Forecast Mainland Facilities & Equipment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Other						
Equipment	3,497	3,434	3,363	2,664	3,310	2,930
Facilities	3,213	4,177	3,483	4,138	8,424	4,124
	6,710	**7,611**	**6,845**	**6,802**	**11,734**	**7,054**

EQUIPMENT

The forecast expenditures of $3.3 million and $2.9 million in 2012 and 2013 are generally consistent with historical spending, although higher than normal spending was experienced in 2010, when expenditures were $461 thousand higher than approved. This was due to a conversion of some Company vehicles to natural gas, and to the acquisition of CNG refuelling equipment located on FEI's sites in Burnaby and Surrey, which provide fueling service to the Company's fleet.

An increase of $150 thousand in equipment expenditure is required in 2012 for the integration of the radio network system. In an emergency situation, it is critical that the utilities can broadcast "one too many" radio communications to ensure the initial response and the subsequent continuation of service is done in a manner that is timely, cost effective, and above all, preserves the safety of both the public and employees. As such, the Company continues to operate a private radio network throughout its coastal and interior service territories.

6.2.6 CONTRIBUTIONS IN AID OF CONSTRUCTION

6.2.6.1 CIAC - Mainland

The table below summarizes Mainland's anticipated CIAC recoveries for 2012-2013.

Table 6.2-26: Approved, Actual and Forecast Mainland Contributions in Aid of Construction

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital	936	512	(763)	(1,252)	(1,320)	(1,373)
Sustainment Capital	(4,700)	(4,350)	(2,900)	(4,966)	(3,750)	(3,750)
CPCN		(84)				
Retirements	(261)		(266)		(271)	(277)
	(4,025)	**(3,922)**	**(3,929)**	**(6,218)**	**(5,341)**	**(5,400)**

CIAC for 2012 and 2013 are based on recoveries for the forecast customer additions and anticipated receivable work.

In total, CIAC are forecast at $5.3 million in 2012 and $5.4 million in 2013.

For Growth Capital, the 2010 Approved and Actual includes the transfer of the $1.443 million balance in the Deferred Service Line Installation Fee account to CIAC on January 1, 2010, as approved by Commission Order No. G-141-09.

CIAC for Sustainment Capital are anticipated to be $3.7 million in 2012 and 2013. The recoveries in this category were budgeted based on the anticipated receivable work for third party alterations and historical levels of receivable work for Transmission crossing replacements and identified recoverable projects. Higher CIAC is anticipated for 2012 and 2013 due to an increase in receivable work on third party alterations, expected especially as a result of announcements by municipalities to increase infrastructure renewal, for the forecast periods.

6.2.6.2 CIAC - Vancouver Island

The table below summarizes Vancouver Island's anticipated CIAC recoveries for 2012-2013.

Table 6.2-27: Approved, Actual and Forecast Vancouver Island Contributions in Aid of Construction

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital	(117)	(140)	(123)	(123)	(130)	(135)
Sustainment Capital	(310)	(218)	(310)	(350)	(281)	(281)
CPCN						
Retirements	(15)	(13)	(15)	(15)	(15)	(15)
	(442)	**(371)**	**(448)**	**(488)**	**(426)**	**(431)**

CIAC for 2012 and 2013 are based on recoveries for the projected customer additions and anticipated receivable work.

CIAC of $426 thousand and $431 thousand for 2012 and 2013 respectively are consistent with average contributions over the 2010 – 2011 period.

6.2.6.3 CIAC - Whistler

Whistler does not anticipate any contributions for the 2012-2013 forecast period.

6.2.6.4 CIAC - Fort Nelson

Fort Nelson does not anticipate any contributions for 2012-2013 forecast period.

6.2.7 CPCNs

Section 45(1) of the UCA requires that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the Commission a CPCN approving the construction or operation. Section 46(1) of the UCA requires an application for a CPCN be filed with Commission.

As agreed to in the 2010-2011 RRAs for the Mainland and Vancouver Island, large capital expenditures over $5 million (excluding AFUDC) qualify for the CPCN application process. This threshold has been in place since 2003. The 2010 Certificates of Public Convenience and Necessity Application Guidelines, issued March 18, 2010, provide general guidance regarding the Commission's expectations of the information that should be included in a CPCN Application.

As CPCNs are approved through a separate process, we have not included in this RRA the capital expenditures related to CPCNs that are anticipated but have not yet been approved. CPCNs that have been approved and are forecast to go into service during the test years are included in rate base in this RRA.

TILBURY LAND PROPERTY PURCHASE

In October of 2009, FEI filed a CPCN application for the acquisition of the Tilbury Property, immediately adjacent to the Tilbury LNG Facility, at a cost close to $16 million. On April 27, 2010, the Commission granted a CPCN for the Property by Order No C-2-10, with a condition that generally results in the amount of land to be added to rate base January 1, 2012 being reduced by that portion of the Property to be subdivided and sold. As a result, of the total Property purchase price, $14.2 million will be added to rate base January 1, 2012.

KOOTENAY RIVER CROSSING (SHOREACRES) PROJECT

In July of 2010, FEI field an application for a CPCN to replace the aerial pipeline crossing of the Kootenay River located near the community of Shoreacres with a new crossing by means of a horizontal directional drill as part of the Interior Transmission System. On November 10, 2010, the Commission granted a CPCN for the Project by Order No. C-9-10 for an estimated $8.3 million including AFUDC and with a projected in service date of October, 2011. The cost is now projected at $9.7 million including, AFUDC, with an in service date of May 1, 2012.

Deleted: Current estimates remain at the CPCN estimates for both project costs and in service date

6.2.7.2 Mainland CPCNs - Anticipated Projects

HUNTINGDON STATION BYPASS

FEI's Huntingdon Control Station, located on the Canada/US border south of Abbotsford, controls the supply of natural gas to the majority of customers in the Lower Mainland and all of the customers in Whistler, Squamish, the Sunshine Coast, and Vancouver Island. In total, approximately 660,000 customers depend on Huntingdon for their gas supply. The Huntingdon Control Station, originally commissioned in 1956 has been continually operated, upgraded and maintained to ensure the station remains fit for service. Through operational experience and risk assessments, FEI identified the station as a potential "single point of failure," meaning that the failure of the station would cause the complete outage of the entire gas system. This failure event could be caused by equipment failures, natural hazards, vandalism, or failures of adjacent interconnected midstream pipelines and facilities. The risk of a failure event due to such an incident is amplified by a lack of redundancy within certain parts of the station.

In order to ensure reliable gas supply to the approximately 660,000 FEI customers who depend on Huntingdon, FEI proposes constructing a bypass pipeline around Huntingdon Station and the associated interconnection facilities that will provide redundancy to the overall system and mitigate the impact of a major incident at Huntingdon from any of the failure scenarios listed above. The Company plans to submit a CPCN application in the second quarter of 2011 for the installation of the station bypass, to be completed before the 2012/13 winter season. The current project cost is estimated at $25 - $30 million.

Deferral Account Category	General Purpose & Description
Residual	• Deferral accounts which are no longer required and the Company is proposing to discontinue the use of the account. • Typically the proposal is to fully amortize any remaining balances.

The forecast mid-year balance of unamortized deferred charges in rate base for the FEUs is approximately $58.5 million in 2012 and $81.9 million in 2013 and is driven largely by the balances in the Whistler Pipeline and Energy Efficiency and Conservation accounts. Figure 6.3-1 provides the mid-year deferral account balances summarized by deferral account category.

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Figure 6.3-1: FEU Forecast Mid-Year Balances of Deferral Accounts by Category

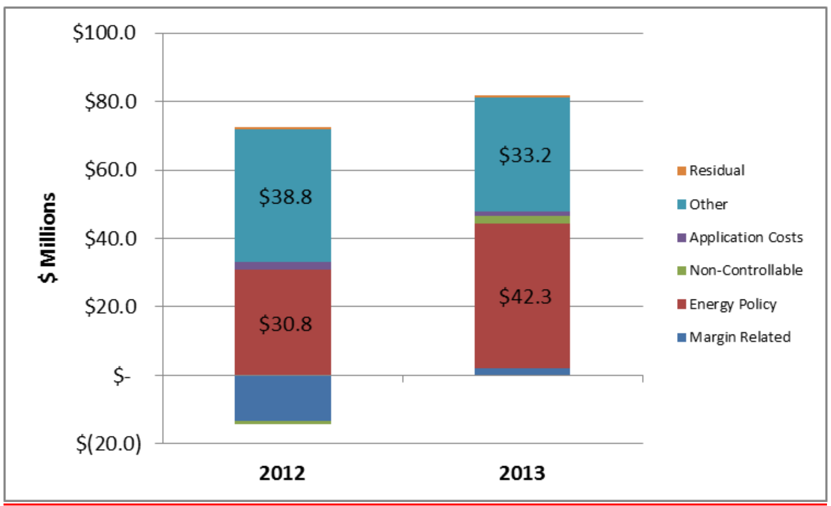

Table 6.3-2 provides the forecast mid-year balances of the deferral account by Category and by Utility and the following sections describe each rate base deferral account in detail, grouped by the six categories. For a discussion on non-rate base deferral accounts, including the Thermal Energy Services Deferral Account (formerly the New Energy Solutions Deferral Account), please refer to Appendix G.

Table 6.3-2: Forecast Mid-Year Balances of Deferral Accounts by Category[131]

2012 Forecast, Mid Year Balance, ($ thousands)	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Margin Related	$ (10,027)	$ (4,062)	$ 703	$ (41)	$ (13,427)
Energy Policy	27,599	3,163	75	-	30,837
Non-Controllable	(594)	40	(189)	(4)	(746)
Application Costs	1,992	172	147	3	2,313
Other	11,902	66	26,773	52	38,794
Residual	711	-	-	-	711
Mid Year Balance, Deferral Accounts	**$ 31,583**	**$ (621)**	**$ 27,509**	**$ 10**	**$ 58,481**

2013 Forecast, Mid Year Balance, ($ thousands)	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Margin Related	$ 1,544	$ -	$ 480	$ (8)	$ 2,017
Energy Policy	37,805	4,316	218	-	42,339
Non-Controllable	2,259	35	(115)	(2)	2,177
Application Costs	1,368	72	9	1	1,450
Other	6,247	932	25,958	91	33,228
Residual	684	-	-	-	684
Mid Year Balance, Deferral Accounts	**$ 49,909**	**$ 5,355**	**$ 26,550**	**$ 82**	**$ 81,896**

6.3.1 MARGIN RELATED DEFERRAL ACCOUNTS

The Utilities have included the following previously approved Margin Related Deferrals in rate base for 2012 and 2013:

[131] Section 7.1 to 7.4, Schedules 66 to 71

Table 6.3-3: Margin Deferral Accounts Designed to Reduce Rate Volatility[132]

2012 Forecast, Mid Year Balance, ($ thousands)					
Margin Related Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Commodity Cost Reconciliation Account (CCRA)	$ (11,604)	$ -	$ (88)	$ -	$ (11,692)
Midstream Cost Reconciliation Account (MCRA)	15,506	-	99	-	15,604
Revenue Stabilization Adjustment Mechanism (RSAM)	(6,937)	-	703	(16)	(6,250)
Interest on CCRA/MCRA/RSAM/Gas in Storage	(2,164)	-	(11)	3	(2,172)
Revelstoke Propane Cost Deferral Account	94	-	-	-	94
Gas Cost Variance Account	-	(4,062)	-	-	(4,062)
Fort Nelson Gas Cost Reconciliation Account	-	-	-	(28)	(28)
SCP Mitigation Revenues Variance Account	(4,922)	-	-	-	(4,922)
Total Mid Year Balance, Margin Related Deferrals	**$ (10,027)**	**$ (4,062)**	**$ 703**	**$ (41)**	**$ (13,427)**

2013 Forecast, Mid Year Balance, ($ thousands)					
Margin Related Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Commodity Cost Reconciliation Account (CCRA)	$ -	$ -	$ -	$ -	$ -
Midstream Cost Reconciliation Account (MCRA)	9,303	-	59	-	9,363
Revenue Stabilization Adjustment Mechanism (RSAM)	(4,162)	-	422	(9)	(3,750)
Interest on CCRA/MCRA/RSAM	(1,007)	-	(1)	2	(1,006)
Revelstoke Propane Cost Deferral Account	-	-	-	-	-
Gas Cost Variance Account	-	-	-	-	-
Fort Nelson Gas Cost Reconciliation Account	-	-	-	-	-
SCP Mitigation Revenues Variance Account	(2,590)	-	-	-	(2,590)
Total Mid Year Balance, Margin Related Deferrals	**$ 1,544**	**$ -**	**$ 480**	**$ (8)**	**$ 2,017**

6.3.1.1 Commodity Cost Reconciliation Account (CCRA)

The CCRA applies to Mainland and Whistler and was approved by Commission Order No. G-25-04 for Mainland and Commission Order No. G-138-10 for Whistler. The CCRA captures the costs incurred by Mainland and Whistler to purchase its portion of the baseload commodity supply under the Essential Services Model and the commodity recovery revenues received from sales customers choosing to remain on the utility standard rate offering. Commodity price-related variances collected in the CCRA are taken into account when determining future commodity rate changes. The commodity rate is reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Based on the recommendations within the FEI Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms (the "CCRA / MCRA Review Report"), dated March 10, 2011, a secondary parameter of a minimum rate change threshold value of $0.50/GJ would be added to the existing rate change trigger mechanism to avoid minor changes to the commodity rate which can occur in low commodity price environments when using only a percentage-based threshold. Generally, when the commodity rate is reset, the new rate is designed to recover, or refund, over the next 12 months any existing CCRA balance,

[132] Section 7.1 to 7.4, Schedule 68 and 70

Table 6.3-4: Mid-Year Balances of Energy Policy Deferrals[134]

2012 Forecast, Mid Year Balance, ($ thousands)					
Energy Policy Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Energy Efficiency & Conservation (EEC)	$ 22,720	$ 3,147	$ 75	$ -	$ 25,941
NGV Conversion Grants	101	17	-	-	118
Emissions Regulations	-	-	-	-	-
2010-2011 Biomethane Program Costs	748	-	-	-	748
2011 CNG and LNG Service Costs and Recoveries	(24)	-	-	-	(24)
NGV Incentives	4,054	-	-	-	4,054
Total Mid Year Balance, Energy Policy Deferrals	**$ 27,599**	**$ 3,163**	**$ 75**	**$ -**	**$ 30,837**

2013 Forecast, Mid Year Balance, ($ thousands)					
Energy Policy Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Energy Efficiency & Conservation (EEC)	$ 33,219	$ 4,290	$ 218	$ -	$ 37,727
NGV Conversion Grants	119	26	-	-	145
Emissions Regulations	-	-	-	-	-
2010-2011 Biomethane Program Costs	449	-	-	-	449
2011 CNG and LNG Service Costs and Recoveries	(36)	-	-	-	(36)
NGV Incentives	4,054	-	-	-	4,054
Total Mid Year Balance, Energy Policy Deferrals	**$ 37,805**	**$ 4,316**	**$ 218**	**$ -**	**$ 42,339**

6.3.2.1 Energy Efficiency and Conservation (EEC)

Pursuant to Commission Order No. G-36-09, the Commission approved the use of a deferral account for EEC expenditures for Mainland and Vancouver Island. The decision also approved the inclusion of the forecast deferral account balances in rate base on a net-of-tax basis and to amortize these balances in rates over a ten year period. The Companies propose that the deferral account mechanism be modified to address variances in the level of customer participation as well as to address the expansion of the EEC program to Whistler.

In this Application the Companies are seeking the following approvals related to EEC:

1. An increase from $35.3 million (the approved EEC funding envelope in 2011) to a total of $64.5 million in 2012 and remaining at that level in 2013 for Mainland, Vancouver Island and Whistler combined;
2. Combined EEC rate base deferral account additions of $20.0 million in 2012 and $20.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period;
3. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is

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[134] Section 7.1 to 7.4, Schedule 68 and 70

approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler;

4. The creation of the EEC Incentive non-rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.

All costs incurred by the Companies continue to be subject to the guidelines of the EEC Application, as approved by Commission Order No. G-36-09. The four requests are discussed in further detail below.

INCREASE TO EEC FUNDING

In this Application, the Companies are seeking approval of an increase to the EEC funding envelope from the 2011 approved amount of $35.3 million to $64.5 million for 2012 and 2013.

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Table 6.3-5 below summarizes the various areas of activity to be funded by the proposed EEC expenditure.

Table 6.3-5: Proposed EEC Funding by Activity for 2012 and 2013

	2012 Proposed Funding ($000s) Total	2013 Proposed Funding ($000s) Total
Previously Approved EEC Activity		
Conventional EEC Activity		
Residential	9,500	9,500
High Carbon Fuel Switching	2,000	2,000
Low Income	5,000	5,000
Commercial	14,500	14,500
Conservation Education and Outreach	5,000	5,000
Industrial	2,000	2,000
Subtotal - Conventional EEC Activity	***38,000***	***38,000***
Subtotal - Innovative Technologies	***1,500***	***1,500***
Subtotal - Previously Approved EEC Activity	***39,500***	***39,500***
New Initiatives		
Furnace Scrap-It Program	10,000	10,000
Solar Thermal	4,000	4,000
TES for Schools	11,000	11,000
Subtotal - New Initiatives	**25,000**	**25,000**
Total Funding	**64,500**	**64,500**

This level of funding is necessary to build on the significant progress that has been made toward building a strong foundation for future growth in EEC activity, to support new EEC programs and to make EEC programs available to customers in Whistler[135] in addition to customers on the Mainland and Vancouver Island and to include Industrial customers of FEVI in eligibility for EEC program participation. Further, the FEU have put forth new programs such as Furnace Scrap-It program, Solar Thermal and TES for Schools. Appendix K provides a review of the proposed EEC activity for 2012 and 2013, and the EEC-related approvals sought along with supporting information.

Deleted: Further, in this RRA, the Utilities have requested $10 million in 2012 and $10 million in 2013 to fund its natural gas for Transportation initiatives within the Innovative Technologies Program Area.

The table below provides a summary of the 2010 through 2013 EEC activity:

Table 6.3-6: A Significant Increase in EEC Funding is Proposed

($ millions)	2010		2011		2012	2013
Utility/Region	*Approved*	*Actual*	*Approved*	*Projected*	*Forecast*	*Forecast*
FEI	25.8	11.1	29.6	14.8		
FEVI	5.2	1.5	5.7	2.0	64.5	64.5
FEW	-	-	-	-		
Total	**31.0**	**12.6**	**35.3**	**16.8**	**64.5**	**64.5**

EEC FORECAST INCLUDED IN RATE BASE

The Companies are seeking approval to include $20 million per year in the EEC rate base deferral account, slightly more than 30 percent of the total forecast, to recognize the variability in customer participation that may occur in the forecast period. As discussed below, the remaining $44.5 million per year of the forecast EEC costs will be accumulated, on an actual as-spent basis, in a non-rate base deferral account, attracting AFUDC. This approach helps to protect customers from paying for EEC expenditures in 2012 and 2013 until program results are known.

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The Companies believe that $20 million per year is an appropriate forecast to include in the rate base deferral account for 2012 and 2013 because of the following:

1. $20 million is in line with the total projected EEC costs for 2011.
2. As demonstrated in the 2010 EEC Annual Report, FEI's recent experience of the ratio between non-incentive costs to incentive costs is approximately 35 percent.[136]

[135] In Appendix A (page 7), Reasons for Decision accompanying Commission Order No. G-138-10, Whistler was directed to develop plans for EEC programs consistent with British Columbia's energy objectives in its next revenue requirement application

[136] Appendix K; Non incentive costs of $6.283 million compared to total costs of $17.701 million as shown on Page 6

3. $20 million reflects the approximate level of non-incentive costs like labour, customer education and general administrative expenses required to deliver an EEC program of $64.5 million.

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ALLOCATION OF EEC FORECAST IN RATE BASE

The Companies are seeking approval to allocate the forecast costs included in the rate base deferral account on an average customer basis amongst Mainland, Vancouver Island and Whistler. This results in rate base deferral account additions as follows:

Table 6.3-7: EEC Additions Allocated Based on Average Customers

($ millions) **Utility/Region**	EEC Rate Base Additions		
	Allocation	**2012**	**2013**
FEI	89%	17.8	17.8
FEVI	10%	2.0	2.0
FEW	1%	0.2	0.2
Total	100%	20.0	20.0

The allocation of the forecast costs in rate base on an average customer basis is appropriate because the programs will be available to customers in all regions.

EEC INCENTIVE NON-RATE BASE DEFERRAL ACCOUNT

The Companies are seeking approval of a non-rate base deferral account, attracting AFUDC, to capture the remaining portion of EEC costs as incurred on an actual basis, to a maximum of $44.5 million each year amongst the Companies. The non-rate base account reduces the risk of variability in EEC costs of customer participation in program costs that are embedded in delivery rates. That is, costs incurred over and above the forecast EEC rate base account additions of $20.0 million in 2012 and 2013 will be captured in the EEC Incentive non-rate base account. The additions to the non-rate base account will be tracked on a Company basis for Mainland, Vancouver Island and Whistler.

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Consistent with the rate base deferral accounts, the balance in the non-rate base account will be recovered over a ten year period. The recovery of the balance will commence in 2014, with the method of recovery to be determined as a part of the next Revenue Requirement.

6.3.2.2 NGV Conversion Grants

Mainland and Vancouver Island maintain a NGV Conversion Grant Program, as approved by Commission Order No. G-98-99 for FEI and Commission Order No. G-140-09 for FEVI. The NGV Conversion Grant program is not a part of the EEC Program maintained by FEI and FEVI.

and is amortized through delivery rates over a three year period. The 2010 and 2011 costs captured in the deferral account include:

1. The 2010 and 2011 cost of service value related to the assets that are being transferred to Rate Base in 2012 – i.e. Earned Return, Depreciation Provision, and Income Tax; and
2. O&M expenditures (net of tax), consisting of the costs of upgrading the CWLP system to allow the launch of the Green Gas program and the ongoing costs of updating that tariff information, the costs of CWLP answering informational calls regarding the Green Gas program and other planned Customer Education costs and the cost of one FTE to administer the Green Gas program. Additionally, FEI has included the BCUC application costs incurred in support of the Biomethane Application filed on June 8, 2010.

Any variances between the forecast level of 2011 expenditures and actual expenditure levels will be amortized in rates beginning in 2014. Delivery system-related Capital and O&M costs incurred after December 31, 2011 have been forecast as part of this Application and will not be included in this deferral account.

Please refer to Appendix J for a comprehensive report on the biomethane program and details regarding the balance of all deferral accounts associated with biomethane.

6.3.2.5 2011 CNG and LNG Service Costs and Recoveries

In the recent CNG and LNG Service Application, FEI requested approval for a non-rate base deferral account attracting AFUDC to capture the O&M costs and cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period. FEI has captured the forecast costs and revenues associated with the Waste Management Fueling Station agreement, as well as two additional fueling station agreements which are anticipated to be in-service in 2011, in this non-rate base deferral account, and has transferred the projected balance to rate base January 1, 2012 with three year amortization. Any variances between the forecast level of 2011 expenditures and revenues and actual expenditure and revenue levels will be amortized in rates beginning in 2014. CNG and LNG Service costs and recoveries incurred after December 31, 2011 are embedded in this Application and used in the determination of the revenue requirements for 2012 and 2013.

Deleted: The forecasts made in relation NGV refuelling infrastructure in the 2012-2013 RRA are premised on the assumption that the CNG and LNG Service Application will be approved as filed. Further, it is also based on the premise that the EEC incentives for natural gas for Transportation will continue. If necessary, FEI will file an evidentiary update to this application to take into account the Commission's Decision on the CNG and LNG Service Application once it is available

Please refer to Appendix I for a comprehensive report on the CNG and LNG Fueling Program and details regarding the balance of all deferral accounts associated with the program.

6.3.2.6 CNG and LNG Recoveries

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In its recent CNG and LNG Service Application dated December 1, 2010, FEI requested approval for an ongoing rate base deferral account to capture incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand. In this Application, FEI is seeking approval to expand this account to include variations from the revenue forecast pertaining to Rate Schedule 16. FEI believes that a deferral account is appropriate because Rate Schedule 16 is a relatively new rate schedule and at the time of this filing we have no customers using this service. It is expected that Vedder Transportation will be the first customers to use this Rate Schedule beginning in the second half of 2011. While FEI believes its CNG and LNG forecasts to be reasonable, FEI believes that both the customer and the shareholder should be kept whole with respect to Rate Schedule 16 and fuelling station recoveries for CNG and LNG Service and that a deferral account mechanism is appropriate, at least for the 2012 and 2013 forecast period.

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Additions to this account over the forecast period will be recovered from or refunded to all non-bypass customers beginning in 2014. Please refer to Appendix I for a comprehensive report on the CNG and LNG Fueling Program.

6.3.2.7 NGV Incentives

$5.6 million has been included in the NGV Incentives deferral account, with the recovery period to be determined pending any further review and decision on the prudency of these amounts.

6.3.3 NON-CONTROLLABLE DEFERRAL ACCOUNT ITEMS

The Utilities have included the following previously approved and new Non-Controllable Items deferrals in rate base for 2012 and 2013 as shown in Table 6.3-8. As discussed in Section 3, Vancouver Island is seeking approval for the continuation of the RSDA for the 2012 and 2013 forecast period. In the absence of the RSDA, Vancouver Island would seek approval of Non-Controllable Item deferral accounts similar to those employed in Mainland, Whistler and Fort Nelson.

Table 6.3-8: Non-Controllable Item Deferral Accounts[137]

2012 Forecast, Mid Year Balance, ($ thousands)					
Non-Controllable Items Deferral Accounts	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Property Tax Deferral	$ (1,339)	$ -	$ 80	$ (2)	$ (1,262)
Insurance Variance	(578)	-	-	-	(578)
Pension & OPEB Variance	7,978	-	-	-	7,978
BCUC Levies Variance	118	-	-	-	118
Interest Variance	(3,928)	-	(275)	(2)	(4,204)
Tax Variance Account	(3,513)	-	(1)	-	(3,514)
Vancouver Island HST Implementation	-	(66)	-	-	(66)
Olympic Security Costs	285	67	2	-	353
IFRS Conversion Costs	384	39	5	-	428
Customer Service Variance Account	-	-	-	-	-
Total Mid Year Balance, Non-Controllable Items Deferrals	**$ (594)**	**$ 40**	**$ (189)**	**$ (4)**	**$ (746)**

2013 Forecast, Mid Year Balance, ($ thousands)					
Non-Controllable Items Deferral Accounts	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Property Tax Deferral	$ (593)	$ -	$ 50	$ (1)	$ (543)
Insurance Variance	-	-	-	-	-
Pension & OPEB Variance	4,787	-	-	-	4,787
BCUC Levies Variance	-	-	-	-	-
Interest Variance	(2,157)	-	(165)	(1)	(2,323)
Tax Variance Account	-	-	-	-	-
Vancouver Island HST Implementation	-	-	-	-	-
Olympic Security Costs	94	22	(2)	-	114
IFRS Conversion Costs	128	13	2	-	143
Customer Service Variance Account	-	-	-	-	-
Total Mid Year Balance, Non-Controllable Items Deferrals	**$ 2,259**	**$ 35**	**$ (115)**	**$ (2)**	**$ 2,177**

6.3.3.1 Property Tax Deferral

The Company has limited ability to influence property taxes, which are imposed by municipalities and other levels of government, and are influenced by assessed property values, mill rates, and shortfalls in other areas within a municipal boundary. A significant portion of property taxes is tied to the amount of revenues collected within municipalities ("1 percent in lieu" tax), and fluctuates with commodity-related variations in revenues. Mainland, Whistler and Fort Nelson will continue to defer the variance between actual and forecast property taxes, as most recently approved by Commission Order No. G–51-03 for FEI, Commission Order No. G-35-09 for Whistler and Commission Order No. G-27-11 for Fort Nelson. Any variances in amounts forecast will be amortized in rates starting in 2014.

[137] Section 7.1 to 7.4, Schedule 68 and 70

Deleted: ***<#>Vancouver Island Joint Venture Litigation Costs Account¶***
In this Application, Vancouver Island is seeking approval for a deferral account to capture the legal costs of $130 thousand incurred defending a lawsuit filed by the Vancouver Island Gas Joint Venture (VIGJV). This lawsuit was dismissed in January 2010. The basis of this lawsuit was alleged overpayment of past tolls and declarations for reduction of future tolls. Had the VIJV been successful in their claim, it would have likely resulted in additional costs and a reallocation of cost of service for all other customers. Vancouver Island is seeking approval to amortize this account through delivery rates in 2012.

6.3.4 DEFERRED COSTS OF APPLICATIONS

The Utilities have included the following previously approved and new deferrals related to costs of filing regulatory applications in rate base for 2012 and 2013:

Table 6.3-10: Approved and Forecast Application Cost Accounts[138]

2012 Forecast, Mid Year Balance, ($ thousands)					
Application Costs Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
2009 ROE & Cost of Capital Application	$ 582	$ 34	$ 4	$ -	$ 621
2010-2011 Revenue Requirement Application	(82)	-	132	-	50
2012-2013 Revenue Requirement Application	654	70	7	3	734
CCE CPCN Application	178	17	2	-	197
NGV for Transportation Application	123	-	-	-	123
Victoria Regional Office CPCN	-	35	-	-	35
AES Inquiry Cost	393				393
Long Term Resource Plan Application	144	16	2	-	162
Total Mid Year Balance, Application Costs Deferrals	**$ 1,992**	**$ 172**	**$ 147**	**$ 3**	**$ 2,313**

2013 Forecast, Mid Year Balance, ($ thousands)					
Application Costs Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
2009 ROE & Cost of Capital Application	$ 414	$ 20	$ 3	$ -	$ 437
2010-2011 Revenue Requirement Application	-	-	-	-	-
2012-2013 Revenue Requirement Application	218	23	2	1	245
CCE CPCN Application	122	11	1	-	134
NGV for Transportation Application	74	-	-	-	74
Victoria Regional Office CPCN	-	-	-	-	-
AES Inquiry Cost	382				382
Long Term Resource Plan Application	159	18	3	-	180
Total Mid Year Balance, Application Costs Deferrals	**$ 1,368**	**$ 72**	**$ 9**	**$ 1**	**$ 1,450**

6.3.4.1 Revenue Requirements and Long Term Resource Plan

FEI will incur costs in 2011 and 2012 to prepare various recurring applications such as the current Revenue Requirement Application and the Long Term Resource Plans. 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. FEI is proposing to allocate 10 percent of these costs to Vancouver Island and 1 percent of these costs to Whistler, based on number of customers. Consistent with past practice, FEI proposes to defer the costs incurred in 2011 for recovery over 2012 and 2013 for the Revenue Requirement

[138] Section 7.1 to 7.4, Schedule 69 and 71

Application, and over two years beginning in 2013 for the Long Term Resource Plan application costs. Any variances between the forecast account balances and the actual incurred costs will be amortization in rates starting in 2014.

The application cost deferral accounts pertaining to the 2010 and 2011 Revenue Requirements, the 2009 ROE and Cost of Capital and the CCE CPCN were approved by Commission Order No. G-141-09 for Mainland, Commission Order No. G-140-09 for Vancouver Island and Commission Order No.138-10 for Whistler and Commission Order No. G-27-11 for Fort Nelson. The 2010 and 2011 revenue requirement application costs are expected to be fully amortized by December 31, 2012 for Mainland, Vancouver Island and Whistler. The 2009 ROE and Cost of Capital and CCE CPCN costs have been amortized over five years in all of the Utilities and are expected to be fully amortized by December 31, 2014.

6.3.4.2 NGV for Transportation Application

In the NGV Application filed on December 1, 2010, FEI requested approval for a non-rate base deferral account attracting AFUDC to capture the NGV Fueling Service Application costs incurred in 2010 and 2011 and to recover these costs from all non-bypass customers by transferring the account to rate base and amortizing the balance through delivery rates commencing January 1, 2012 over a three year period. For purposes of determining its 2012 and 2013 revenue requirements, FEI has included this account and its amortization. Any variances between the forecast account balances and the actual incurred costs will be amortization in rates starting in 2014.

6.3.4.3 Victoria Regional Centre CPCN

In accordance with Commission Order No. C-6-11, FEVI has captured application costs associated with the Victoria Regional Office Facility CPCN incurred in 2010 and 2011, in a deferral account. In this Application, FEVI is seeking approval to amortize the balance through rates in 2012. Any variances between the forecast account balances and the actual incurred costs will be amortization in rates starting in 2014.

6.3.4.4 AES Inquiry Costs

FEI has forecast the costs associated with the AES Inquiry in a rate base deferral account (the AES Inquiry Cost deferral account) on a net of tax basis, with amortization over a five-year period commencing in 2012. FEI forecasts approximately $480 thousand in costs in 2011 and an additional $200 thousand in costs in 2012. FEI will capture the 2011 costs in a non-rate base deferral account and will transfer the balance to the rate base AES Inquiry Cost deferral account effective January 1, 2012. The forecast costs consist of legal fees, costs for witnesses and consultants, intervener and participant funding costs, Commission costs, and miscellaneous facilities, stationary and supplies costs.

6.3.5 OTHER DEFERRAL ACCOUNTS

The Utilities have included the following previously approved and new deferrals in rate base for 2012 and 2013:

Table 6.3-11: Balance in Other Deferrals Largely Due to Whistler Conversion[139]

2012 Forecast, Mid Year Balance, ($ thousands)					
Other Deferral Accounts	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Whistler Pipeline and Conversion Costs	$ -	$ -	$ 12,918	$ -	$ 12,918
Whistler Capital Contribution to Vancouver Island	-	-	13,724	-	13,724
Pipeline Contribution Costs Variance Account	-	-	(217)	-	(217)
Pension & OPEB Funding	(104,859)	(16,682)	-	-	(121,541)
Deferred Removal Costs	2,184	336	3	-	2,522
Gains and Losses on Asset Disposition	11,064	1,016	72	96	12,249
2011 Muskwa River Crossing				(44)	(44)
US GAAP Conversion Costs	256	29	3		287
US GAAP Pension & OPEB Funded Status	79,958	11,922	-		91,880
US GAAP Transitional Costs	(1,444)	(361)	-		(1,805)
PCEC Start Up Costs	-	1,030	-	-	1,030
2010-2011 Customer Service O&M and COS	23,876	2,679	261	-	26,816
Gas Asset Records Project	534	60	6	-	600
BC OneCall Project	334	38	4		375
Total Mid Year Balance, Other Deferrals	**$ 11,902**	**$ 66**	**$ 26,773**	**$ 52**	**$ 38,794**

2013 Forecast, Mid Year Balance, ($ thousands)					
Other Deferral Accounts	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Whistler Pipeline and Conversion Costs	$ -	$ -	$ 12,178	$ -	$ 12,178
Whistler Capital Contribution to Vancouver Island	-	-	13,435	-	13,435
Pipeline Contribution Costs Variance Account	-	-	-	-	-
Pension & OPEB Funding	(105,071)	(15,021)	-	-	(120,092)
Deferred Removal Costs	728	112	1	-	841
Gains and Losses on Asset Disposition	10,497	964	69	91	11,621
2011 Muskwa River Crossing				-	-
US GAAP Conversion Costs	256	29	3		287
US GAAP Pension & OPEB Funded Status	75,515	11,360	-		86,875
US GAAP Transitional Costs	(496)	(283)	-		(779)
PCEC Start Up Costs	-	986	-	-	986
2010-2011 Customer Service O&M and COS	22,366	2,510	245	-	25,121
Gas Asset Records Project	1,535	173	17	-	1,725
BC OneCall Project	918	103	10		1,031
Total Mid Year Balance, Other Deferrals	**$ 6,247**	**$ 932**	**$ 25,958**	**$ 91**	**$ 33,228**

6.3.5.1 Whistler Pipeline and Conversion Costs

Pursuant to Commission Order No. G-53-06, Commission Order No. G-35-09 and Commission Order No. G-138-10, Whistler maintains four deferral accounts related to pipeline and conversion costs that began amortizing in delivery rates effective January 1, 2010, over a 20 year period. No further additions will occur to these accounts.

For presentation purposes[140], Whistler has summarized the pipeline and conversion cost accounts into one account as shown in Table 6.3-12.

[139] Section 7.1 to 7.4, Schedule 69 and 71
[140] Whistler will continue to maintain the four deferral accounts related to pipeline and conversion costs separately

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Asset Disposition account and to amortize the total balance in this account in delivery rates over 20 years, aligned with the average service life of the asset categories that are contributing to the losses.

6.3.5.7 2011 Muskwa River Crossing

This deferral account refunds to customers the 2011 cost of service associated with the Muskwa River Crossing Project that was recovered from customers through 2011 delivery rates.

6.3.5.8 US GAAP Deferral Accounts

FEU is proposing two deferral accounts, in addition to the US GAAP Conversion Costs approved by Commission Order No. G-117-11:

- US GAAP Transitional Account: A new one-time deferral account to capture the unamortized pension and OPEB transitional obligation amortized by plan over expected average remaining service life ("EARSL") with an offsetting entry to the Pension & OPEB Funding deferral account. We have selected the EARSL by plan, to amortize this obligation over, since it results in a similar total expense to what would have been recorded under Canadian GAAP; and

- US GAAP Pension and OPEB Funded Status Account: A new and ongoing deferral account to capture the annual pension and OPEB funded status adjustment, with an offsetting entry to the Pension & OPEB Funding deferral account.

6.3.5.9 PCEC Start Up Costs

The PCEC Start Up Costs deferral includes the unrecovered balance of the original amount of pre-start up costs of $1,754,000 incurred by PCEC to operate a portion of the Vancouver Island pipeline facilities for several months prior to the "in-service" date of October 1, 1991. Vancouver Island began amortizing these costs over 40 years on October 1, 1994 in accordance with the Binding Agreement.

Deleted: *<#>IFRS Transitional Adjustments*¶
In their 2010-2011 RRAs, the Utilities had forecast the adoption of IFRS in 2011. Under IFRS there is a one-time reset of the net pension asset/liabilities, resulting in any unamortized actuarial losses, past service cost and transitional obligations being recognized in retained earnings. Consistent with the approved treatment in the 2010-2011 RRAs, the Utilities have recorded this one-time adjustment in the IFRS Transitional Deferral Account, but due to the one-year deferral of adoption of IFRS, the entry has been made as of January 1, 2012 instead of January 1, 2011 as originally forecast. Table 6.3.13 below shows the composition of this entry for the Mainland and Vancouver Island. ¶
Table 6.3-13: Pension and OPEB Transitional Adjustment on Adoption of IFRS ¶
($ thousands) ¶

	Per
Mainland- M&E Legacy Plan	$ 1[illegible]
Mainland- M&E TI Plan	([illegible]
Mainland- Cope and IBEW Plan	3[illegible]
Mainland	4[illegible]
Vancouver Island	[illegible]
FortisBC Energy Utilities	$ 5[illegible]

¶
The Utilities have considered alternative methods to amortize this IFRS Transitional Adjustment into delivery rates. We have selected the expected average remaining service life ("EARSL") by plan, to amortize this obligation over, since it results in a similar total expense to what would have been recorded under Canadian ...

Deleted: Fort Nelson is proposing a new deferral account with a credit balance of $87,000, amortized to customers in 2012.

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Deleted: *<#>IFRS Transitional Adjustments*¶
In their 2010-2011 RRAs, the Utilities had forecast the adoption of IFRS in 2011. Under IFRS there is a one-time reset of the net pension asset/liabilities, resulting in any unamortized actuarial losses, past service cost and transitional obligations being recognized in retained earnings. Consistent with the approved treatment in the 2010-2011 RRAs, ...

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6.3.5.10 2010-2011 Customer Service O&M and Cost of Service

Pursuant to Commission Order No. C-1-10, Commission Order No. G-23-10 and Commission Order No. G-141-09, FEI has transferred the Customer Care Enhancement Project non-rate base deferral account to rate base effective January 1, 2012. This account captures the costs associated with the Project incurred prior to the project implementation and go live date of January 1, 2012 in addition to project costs expected to be incurred in the early months of 2012.[141] In this application FEI is seeking approval to allocate the balance in this deferral account amongst the FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The Companies are seeking approval to amortize this account in delivery rates over eight years, the same amortization period that was used in the CCE Project CPCN Application.

Deleted: ***<#>2011 Kootenay River Crossing Cost of Service¶***
As approved by Commission Order No. C-9-10, FEI has transferred the Kootenay River Crossing Cost of Service non-rate base account to rate base effective January 1, 2012. This account captures the October through December 2011 cost of service related to the plant in service, consisting of depreciation expense, income taxes and earned return and is amortized in delivery rates over a three year period commencing January 1, 2012. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates starting in 2014.

6.3.5.11 Gas Asset Records Project

Governments, Regulators, codes, and best practices have always required that pipeline operators collect, retain and manage records pertaining to their gas system assets. Due to more recent events and resulting public pressure, more stringent requirements have been put in place related to the collection, retention and management of gas system asset records. Along with industry, the FEU must continue to invest to ensure we meet the gas system records collection, retention and management requirements of the codes, regulations and standards that govern our business. The paragraphs that follow provide a summary of what is driving our specific records related actions, what steps we have taken in the last few years, and what we still need to do.

At this time, there are four key external drivers that are prompting the FEU to pursue more rigorous actions with their gas system records. First, on January 17, 2011, The OGC issued a Safety Advisory informing all pipeline operators in BC of their requirements under CSA Z662-07 with respect to records. The Advisory states that;

[141] The approved project costs as per Commission Order No. C-1-10 and Commission Order No. G-23-10 include deferred O&M of approximately $5 million in 2012.

management system (Filenet). It will be implemented approximately equally over four years (2012 - 2015) using internal resources and an external scanning service. When completed, we will have processed the following records:

1. Pipeline Design Files (60 File Drawers)
2. Offsite Files - Project Files located in Interior offices (200 File Drawers)
3. Iron Mountain Files - Previous Engineers' Files (200 Boxes = 100 File Drawers)
4. Iron Mountain Files - OGC Reconciliation Project Files (30 boxes = 15 File Drawers)
5. Shared Drive - OGC Historic Certificate Files (Vancouver Island)

Project 'B' will review and improve the management and control systems related to engineering drawings management to support ongoing sustainment of a single set of current and as built drawings for assets. The review and improvement in the management and control systems will be undertaken to support the revised OGC and APEGBC requirements.

Project 'C' will review historical drawings to determine the best available complete and current set of drawings for each asset. Under this project we estimate that it will be necessary to index and scan approximately 50,000 hard copy drawings into Filenet, and index and move approximately 100,000 drawings from the shared drive into Filenet. We have taken great care to break this project down into manageable components to achieve a successful outcome.

Table 6.3-14: Forecast Costs for Gas Assets Records Project

	2012	2013	2014	2015
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	1,150,000	1,150,000	1,100,000	400,000
Project 'B' – Implement improved drawing management & control systems	350,000	275,000		
Project 'C' - Review & analyze historical drawings	500,000	825,000	1,050,000	1,000,000
Total	2,000,000	2,250,000	2,150,000	1,400,000

In summary, due to more recent events and resulting public pressure, the actions of Governments, Regulators, and Associations are sending a clear and direct signal to pipeline operators with respect to their gas system asset compliance records. That directive is to ensure that gas system asset compliance records are indeed collected, retained and managed prudently. The FEU has been working diligently for quite some time on the management of our gas system asset compliance records. We introduced the FileNet technology, reviewed and assed the state of our historic records and are now seeking funding to complete the work we started in a timely and systematic manner.

- Whistler 2009 Revenue Requirement Application Costs

6.3.6.3 Residual Delivery Rate Riders

FEI is seeking approval to combine three residual non-rate base deferral account balances into one account, the Residual Delivery Rate Riders account, and to recover the balance through delivery rates in 2012. The residual balances in the ROE Revenue Requirement Variance Account (Rate Rider 2) and the Lochburn Land Costs and Delivery Rate Refund Rider accounts (both accounts used Rate Rider 4) are a result of volume variances (the actual volumes for recovery of the riders differed from what was forecast). Approved by Commission Order No. G-158-09, delivery Rate Rider 2 captured the 2009 recoveries associated with the 2009 ROE and Capital Structure Decision and applied to all non-bypass customers. Approved by Commission Order No. G-116-07, delivery Rate Rider 4 was in place April 1, 2008 through March 31, 2009 and captured a refund associated with the sale of land at the Lochburn facilities and applied to all non-bypass customers. Approved by Commission Order No. G-23-09, Rate Rider 4 remained in place April 1, 2009 through December 31, 2009 to refund the balance in the Delivery Rate Refund Rider account to all non-bypass customers. The Delivery Rate Refund Rider account resulted from the recalculation of 2009 delivery rates.

6.3.7 SUMMARY OF DEFERRAL ACCOUNTS

The Companies believe that the deferral accounts requested above serve to add value to customers and our shareholder and appropriately address uncontrollable matters and significant non-recurring items.

In this application, the Companies are requesting approval for twelve new rate base deferral accounts, the setting of, or modification to, the amortization period of eleven rate base deferral accounts, as well as additional requests or changes to five existing rate base deferral accounts. Table 6.3-18 provides a summary of the request for approvals in this Application related to all rate base deferral accounts.

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Table 6.3-18: Summary of 2012 and 2013 Deferral Account Requests

Type of Change	Account	Company	Reference
New Account	Compliance with Emissions Regulations	FEU	Section 6.3.2.3; Additions and Amortization period TBD
	Customer Service Variance Account	FEU	Section 6.3.3.10; Additions and Amortization period TBD
	2012-2013 Revenue Requirement Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2012, allocated to FEU based on average customers
	Long Term Resource Plan Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2013, allocated to FEU based on average customers

Type of Change	Account	Company	Reference
	Gas Assets Records Project	FEU	Section 6.3.5.11; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	BCOneCall Project	FEU	Section 6.3.5.12; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	Residual Delivery Rate Riders	FEI	Section 6.3.6.3; amortization period of 1 year commencing January 1, 2012
	NGV Incentives	FEI	Transfer of NGV Incentives provided to customers for 2010 and 2011 from the EEC deferral account to this new rate base account; disposition to be determined
	AES Inquiry	FEI	Amortization period of 5 years commencing January 1, 2012
	US GAAP Transitional Account	FEI, FEVI	Section 3.2.2; a one-time deferral account to capture the unamortized pension and OPEB transitional obligation amortized by plan over EARSL
	US GAAP Pension and OPEB Funded Status Account	FEI, FEVI	Section 3.2.2; an ongoing deferral account to capture the annual pension and OPEB funded status adjustment
	US GAAP Uncertain Tax Positions	FEI, FEVI	Section 3.2.2; an ongoing non-rate base deferral account to capture any differences that arise from the implementation of US GAAP Financial Accounting Standards Board Interpretation No. 48
Amortization Period Change- New or Modified	Revenue Stabilization Account Mechanism	FEW	Section 6.3.1.3; recovery through Rate Rider 5, 3 year recovery period consistent with FEI and FN, commencing January 1, 2012
	Gas in Storage Interest	FEI	Section 6.3.1.4; 3 year amortization period, commencing January 1, 2012
	Property Tax Variance Account	FEW, FN	Section 6.3.3.1; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Interest Variance Account	FEW, FN	Section 6.3.3.5; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Tax Variance Account	FEW	Section 6.3.3.6; 1 year amortization period, commencing January 1, 2012
	Vancouver Island HST Implementation	FEVI	Section 6.3.3.7; 1 year amortization period, commencing January 1, 2012
	Victoria Regional Centre CPCN	FEVI	Section 6.3.4.3; 1 year amortization period, commencing January 1, 2012
	Deferred Removal Costs	FEU	Section 6.3.5.5; 2 year amortization period, commencing January 1, 2012
	2010-2011 Customer Service O&M and Cost of Service	FEU	Section 6.3.5.9; 8 year amortization period, commencing January 1, 2012

Type of Change	Account	Company	Reference
Other	Energy Efficiency and Conservation	FEU	Section 6.3.2.1; 1. Combined EEC rate base deferral account additions of $20.0 million in 2012 and $20.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period; 2. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and FEW on an average customer basis; 3. The creation of the EEC rate base deferral account for FEW, with additions included on a net-of-tax basis and amortized in rates over a ten year period; 4. The creation of the EEC Incentive non-rate base deferral account for FEI attracting AFUDC, to capture the remaining portion of the EEC costs as incurred and allocated by FEI to each utility based on the actual spend in the service area of each utility in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.
	CNG and LNG Recoveries	FEI	Section 6.3.2.6; inclusion of variations from the revenue forecast pertaining to Rate Schedule 16
	Property Tax Variance Account	FEW	Section 6.3.3.1; include the forecast balance of the existing Propane Plant Property Tax Deferral account in the Property Tax Variance account
	Tax Variance Account	FEI	Section 6.3.3.6; include the balance of the existing LILO reassessment costs deferral into the Tax Variance Account
	Gains and Losses on Asset Disposition	FEU	Section 6.3.5.6; transfer the general plant gains and losses as at January 1, 2010 from the IFRS Transitional account into the Gains and Losses on Asset Disposition account; 20 year amortization period, commencing January 1, 2012
Discontinuance	Residential Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012
	Commercial Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012
	IFRS Transitional Account	FEI, FEVI	Section 3.2.2; discontinuation of this account effective January 1, 2012