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April 11, 2012

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 (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("FEFN" or "Fort Nelson"), FortisBC Energy (Vancouver Island) Inc.) ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW")

Common Rates, Amalgamation and Rate Design Application

The FortisBC Energy Utilities (the "FEU") hereby apply to the British Columbia Utilities Commission (the "Commission") for the necessary approvals pursuant to the *Utilities Commission Act* (the "UCA" or the "Act") to amalgamate into a single entity ("FEI Amalco" or the "Amalgamated Entity") and implement postage stamp rates across the Amalgamated Entity in 2014. A Draft Form of Order setting out the detailed requests has been included as Appendix K-2.

This Application replaces the FEU's Amalgamation and Rate Design Phase 'A' Application, which the FEU are hereby withdrawing as discussed below.

Withdrawal of Amalgamation and Rate Design Phase 'A' Application

On November 1, 2011, the FEU filed the Amalgamation and Rate Design Phase 'A' Application with the Commission seeking approval to amalgamate FEI, FEVI and FEW, and to implement postage stamp rates across all of the FEU's service territories.

On December 6, 2011, the FEU wrote to the Commission that, based on discussions with Commission Staff, filing additional information was advisable to mitigate an extended review process. At that time, the FEU considered that the best approach was to file supplementary evidence. In a letter (Log No. 38097) dated December 19, 2011, the Commission granted the FEU's request to defer further process until such time as the FEU's additional evidence was received.

In examining the additional evidence required for the Application, it has become apparent that it is more efficient for a new application to be filed, rather than supplemental evidence. In addition to the new information requested which needed to be integrated into the application, modifications were required to be made to the proposals as a result of the additional consultation conducted with stakeholders, the commencement of the Commission's Generic Cost of Capital proceeding and the passage of time which makes the implementation of postage stamp rates on January 1, 2013 impossible.

As such, the FEU are withdrawing their Amalgamation and Rate Design Phase 'A' Application filed November 1, 2011 and are submitting the attached 'Common Rates, Amalgamation and Rate Design Application'.

Request for Confidentiality

The FEU are submitting Appendix C-5 of the Application under separate cover requesting that it be treated confidentially. The document, a DBRS bond rating report for FEVI, is relevant to the cost of capital. The report was prepared by DBRS in support of FEVI's "private rating", meaning that it is prepared for FEVI's use and is not available to other DBRS subscribers or the market generally. It is subject to strict confidentiality requirements imposed by DBRS, as the report has commercial value to DBRS. DBRS has provided its consent for the FEU to file the document in accordance with the Practice Directive of the Commission on Confidential Filings. DBRS has consented to the document being made available only to interveners representing customer groups for the exclusive purposes of this proceeding, upon the execution of the Undertaking of Confidentiality provided in Appendix K-3.

If you require further information or have any questions regarding this submission, please contact Paul Craig at 604 592 7459.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed by:

Diane Roy

Attachments

cc (email only): Parties to the FEU 2012-2013 Revenue Requirements and Natural Gas Rates Application

FortisBC Energy Utilities

comprised of:

FORTISBC ENERGY INC.,

FORTISBC ENERGY (VANCOUVER ISLAND) INC., AND

FORTISBC ENERGY (WHISTLER) INC.

Common Rates, Amalgamation and Rate Design Application

Volume 1 - Application

April 11, 2012

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1 EXECUTIVE SUMMARY

1.1 The Approvals Sought

FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEW") (together referred to as the "FortisBC Energy Utilities", the "FEU" or the "Companies"), are applying to the British Columbia Utilities Commission (the "Commission" or "BCUC") for the necessary approvals pursuant to the *Utilities Commission Act* (the "UCA" or the "Act") to amalgamate FEI, FEVI and FEW, as well as Terasen Gas Holdings Inc. ("THI"),[1] into a single entity and implement common rates and services across their service areas[2] starting January 1, 2014. The single amalgamated entity which the FEU are seeking to form will be referred to in this Application as "FEI Amalco" or the "Amalgamated Entity". Common rates are also referred to as postage stamp rates.

The approvals sought in this Application fall into two categories:

- Approvals required to amalgamate the FEU and THI pursuant to section 53 of the Act; and
- Approvals required to adopt common rates for the Amalgamated Entity pursuant to sections 59 to 61 of the Act.

The FEU propose to amalgamate and adopt common rates effective January 1, 2014. A Draft Form of Order setting out the detailed approvals sought has been included as Appendix K-2. Further information on the order sought is provided in Section 2.

The FEU have been operating with a common management structure since the mid-2000s and essentially operate as one amalgamated entity today, with operational savings from integration having been realized over that time. Amalgamation and the adoption of common rates is the next logical step for the Companies under common management. Amalgamation is required in order to implement common rates that will eliminate the existing rate discrepancies across the regions served by the FEU. While common rates result in cost increases to some customers, the move will mitigate significant rate increases for customers on Vancouver Island, the Sunshine Coast and Powell River and will insulate customers in Whistler and Fort Nelson from long-term rate volatility associated with changes in throughput and significant capital investments. It will also facilitate access to the same service offerings across all the areas served by the FEU.

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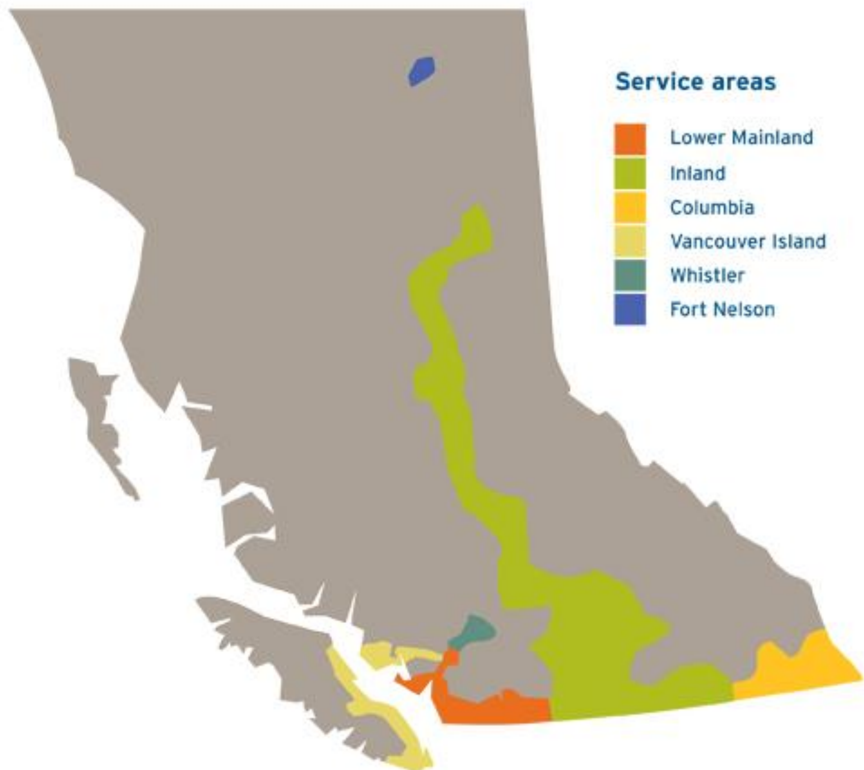
1 The FEU are proposing to amalgamate with THI to simplify its ownership structure. THI's only function is to own approximately 19% of FEI shares. Amalgamating with THI would have no impact to customers or rates.

2 The service areas of FEI include Lower Mainland, Inland, Columbia and Fort Nelson.

1.2 Overview of the FEU

The FEU consist of three legal entities: FEI, FEVI and FEW. While FEVI and FEW each represent a single service area, FEI is comprised of four service areas, the Lower Mainland, Inland, Columbia and Fort Nelson. Although not a separate legal entity, Fort Nelson ("FEFN") has its own rate base for the purposes of determining rates. Thus, although there are only three legal entities, there are four rate bases and six service areas. The FEU's six service areas are shown in the map below:

Figure 1-1: FEU Service Areas



Customers in the Lower Mainland, Inland and Columbia service areas (approximately 850,000 of the FEU's 956,000 customers) are effectively paying common rates. However, the smaller service areas of FEW, FEVI and Fort Nelson pay significantly different rates than these customers.

1.3 Issues Addressed by this Application

The objective of this Application is to address the following issues:

- The current rate discrepancies that exist across the FEU and, in particular, the higher rates paid by FEVI and FEW.

- The expected increase in rates for FEVI due to the loss of government subsidies, including the expiration of the Province's Royalty Revenues,[3] which would further increase the current rate disparity.
- The long-term rate instability for customers of FEVI, FEW and FEFN due to their reliance on smaller, and less diverse customer bases as compared to that of FEI.

Amalgamation and the implementation of postage stamp rates will resolve these issues and provide additional ancillary benefits including expanding access to natural gas services and some savings and efficiencies.

1.4 Review of Options

In order to confirm that amalgamation and postage stamp rates is the preferred solution to meeting its objectives, the FEU compared the option of amalgamating and implementing postage stamp rates to other options. The FEU identified six groupings of options to assess. Of these, the FEU identified four options that generally met its objectives, but required a quantitative review to assess the rate impacts and rate discrepancies amongst the service areas that would result from the options. These options were:

- Option C-1 – FEI, FEVI and FEW amalgamate and implement common rates, except for FEFN which remains as is;
- Option D – Legal amalgamation of the three utilities with the six existing service areas maintained, with the implementation of common delivery and commodity rates and regional midstream rates;
- Option E – Legal amalgamation of the three utilities, with development of east and west service areas and the implementation of common commodity and midstream rates and regional delivery rates across both new service areas; and
- Option F – Legal amalgamation of the three utilities, with implementation of common rates as proposed in this Application.

The FEU then assessed each of the four options against three quantitative objectives: (1) rate differences across the service areas; (2) the per Gigajoule unit cost of service; and (3) revenue to cost ratios.[4] On balance, there is no evidence to suggest that any of the other options are superior to the FEU's preferred option to amalgamate and implement common rates. Only the FEU's preferred option fully meets the FEU's objectives in this Application and provides all of the benefits of common rates.

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3 A discussion on the Royalty Revenues is provided in Section 3.3

4 The range of reasonableness used is 90 percent to 110 percent and is discussed further in the Rate Design Section 9.7.

1.5 Benefits of Amalgamation and Common Rates

The main principle behind common rates is one of fairness amongst all the FEU's customers. Common commodity, midstream and delivery rates will immediately moderate the relatively high natural gas rates in FEW and FEVI. They will also mitigate the expected rate increases faced by FEVI customers following the expiration of government subsidies and the return of the Rate Stabilization Deferral Account ("RSDA") to FEVI's customers. (The balance in the RSDA has been collected from FEVI customers to mitigate the future rate increases FEVI customers would have otherwise paid, absent amalgamation, following the loss of the Royalty Revenues.) Once the rate impacts of common rates are accounted for, common rates will bring more rate stability to all customers and especially customers of FEVI, FEW and the FEI service area of Fort Nelson.

Other benefits of amalgamation and common rates include:

- Simplicity and Ease of Administration: Uniform prices and a reduced number of rate classes and billing determinants (i.e., geographical location) will provide a simpler rate structure that is easier to explain, understand and implement in terms of administration, information requirements and billing procedures. These practical attributes, while not a driver for common rates, are beneficial to our customers.
- Facilitating Consistent Access to Natural Gas Service Offerings: Amalgamation and common rates will facilitate the extension of natural gas services to customers of FEVI, FEW and Fort Nelson. These services include Biomethane service, NGT service,[5] transportation service, and the Customer Choice Program.
- Reporting / Operational Efficiencies: Amalgamation and the adoption of common rate structures for FEI Amalco will create modest efficiencies, through reduced reporting requirements for regulatory, legal and financial filings.

1.6 Implementation of Amalgamation and Postage Stamp Rates

If the Commission determines that amalgamation is beneficial in the public interest, the consent of the LGIC pursuant to section 53 of the UCA is required before amalgamation can take place. Following consent from the LGIC, amalgamation would take place pursuant to the *Business Corporations Act ("BCA")*). Before amalgamation, FEU must update its financing arrangements, communicate with its key counterparties, notify customers of the change in rates and make adjustments to its billing systems.

The operational implications associated with amalgamation and adoption of common rate structures will involve:

[5] Previously referred to by the FEI as Natural Gas Vehicles or NGV, and now referred to as NGT. NGT more accurately describes FEI's target markets and aligns with industry language.

- Replacing the existing Terms & Conditions for each of the companies with a common set of General Terms & Conditions ("GT&Cs") for FEI Amalco. The common set of GT&Cs, similar to those of the current FEI service area, will harmonize tariff, rate design principles and rate classifications across all areas served by FEI Amalco. The FEI Amalco will also employ the approved FEI/FEVI main extension test.
- Combining the current separate gas procurement portfolios and the associated policies and rate constructs.
- Some other minor operational changes that will be required from the Corporate Services, Customer Service, IT and Billing Systems perspectives.

1.7 Common Rates of Amalgamated Entity

The proposed rates for the Amalgamated Entity are addressed briefly below, including amalgamation costs, the combined cost of service, and cost of capital.

The costs associated with amalgamation include legal costs to amalgamate (i.e., supporting the corporate compliance with the *BCA*) and operational costs of implementation (such as training contact centre employees, IT system changes). The FEU have proposed a deferral account to capture these costs, estimated at $2 million. While the costs related to the amalgamation and implementation of postage stamp rates are one-time in nature, any efficiency savings, although not large, will be on-going, and are expected to offset the cost of amalgamation over time. The FEU will pass on to customers any cost savings associated with amalgamation and rate harmonization in 2014 and future years. Amalgamation also results in applying the relatively lower FEI debt rate to FEVI's and FEW's interest expense for the amalgamated cost of service. This yields a net reduction in the amalgamated cost of service of approximately $2 million[6] in 2013 compared to the sum of the individual costs of service for FEI, FEVI, FEW and FEFN.

The cost of service for the Amalgamated Entity has been determined by adding the individual costs of service for FEI Mainland, FEVI, FEW and FEFN, as shown in Appendix J-1, and then adjusting the sum for amalgamation entries. Any changes to the individual cost of service components as determined in the 2012-2013 RRA decision will be flowed through to the amalgamated cost of service.

For the purposes of this application, the FEU are addressing the cost of capital for the FEI Amalco in comparison to the existing pre-amalgamation Benchmark. The FEU believe that, based on the expert evidence filed as part of this Application, it is reasonable to have a 12 basis point premium over the benchmark ROE, which is currently 9.5%, and a capital structure of 40% equity and 60% debt for FEI Amalco. The FEU recognize that the cost of capital for the

[6] Please refer to Appendix J-1, Schedule 3, Column 7, Lines 11 and 16 which detail the changes in the short and long term interest expense of ($2.2) million and $0.2 million respectively. Please refer to Section 8.1.1.5.1 for calculations.

Amalgamated Entity will need to be updated to take into account the outcome of the Generic Cost of Capital proceeding (the "GCOC Proceeding").[7]

As a result of common rates, FEI customers in the Lower Mainland, Inland and Columbia service areas will see a rate increase. The one-time increase will range from 3.7 per cent to 5.4 percent for residential and commercial customers at the burner tip, depending on level of consumption.[8] The FEU propose to mitigate this rate increase for three years. Under this proposal, FEI customers in the Lower Mainland, Inland and Columbia service areas would experience a 2.0 per cent to 3.5 per cent increase to their annual bills in 2014.[9] In 2017, these customers would see a second increase of 1.7 per cent to 1.9 per cent.[10] These estimated increases are calculated at the burner tip and depend on level of consumption.

Fort Nelson customers historically have benefitted from the lowest natural gas rates in the FEU service areas. Their annual natural gas bills would require an increase of between 24 per cent to 55 per cent at the burner tip to bring them on par with other service areas in the FEU.[11] The FEU propose to phase-in this increase by delaying any impact of common rates for five years and then phase-in the increase over the subsequent 10 years, starting in 2019.

As a result of amalgamation and the adoption of common rates, FEVI customers will see rate decreases of between 25 per cent and 44 per cent[12]. FEW customers will see rate decreases of between 37 per cent and 45 per cent[13].

1.8 Amalgamated Entity Rate Design

The Companies propose a rate design based on a Cost of Service Allocation ("COSA") study performed using the amalgamated cost of service for the natural gas utilities. The FEU's work was guided throughout by an external expert in cost allocation and rate design, EES Consulting Ltd.[14] ("EES Consulting"). The proposed rate design has been endorsed by EES Consulting and is consistent with accepted rate design principles. EES Consulting's report is included in Appendix D-1.

The FEU conducted a fully allocated cost of service study that combined each of the FEU's utilities into the Amalgamated Entity and produced postage-stamp delivery, midstream and commodity rates applicable across all service areas. The FEU's COSA analysis was supported

7 BCUC Order No. G-20-12
8 Appendix J-4, Tab 1.1
9 Appendix J-3, Tab 1.1
10 Represents the difference between the full impact of amalgamation (excluding the RSDA rider) of between 3.7 and 5.4 per cent and the mitigated impact of amalgamation (including the 3-year RSDA rider) of between 2.0 and 3.5 per cent.
11 Appendix J-4, Tab 1.4.
12 Appendix J-4, Tab 1.2.
13 Appendix J-4, Tab 1.3Insert reference
14 EES Consulting is a multidisciplinary management consulting firm with particular expertise in Rate Design methodology and Cost of Service Allocation modelling, previously retained by the BCUC, FBC, FEI (Terasen Gas at the time) for the validation of rate design methodologies and models.

by a Minimum System Study, together with a Peak Load Carrying Capability adjustment to classify costs associated with distribution mains. As well, a Customer Weighting Factor Study was employed for the allocation of customer related costs. EES Consulting confirmed that the COSA methodology and model employed for the Amalgamated Entity are consistent with historical and industry practices and the results and conclusions derived are appropriate for the Amalgamated Entity.

The FEI rate structure was adopted for the Amalgamated Entity due to FEI's size in relation to the other Utilities and its more comprehensive service offerings. Mapping of the FEVI, FEW and FEFN rate schedules to FEI's rate schedules was completed based on annual consumption thresholds and contractual requirements of the current FEI rate schedules.

The revenues for each rate class were compared with the allocated cost of service[15] to develop revenue to cost ("R:C") ratios for each rate class. Consistent with past precedents for gas utilities in BC, a "range of reasonableness" of 90 per cent to 110 per cent was used to evaluate the R:C ratios for each rate class. A R:C ratio within the "range of reasonableness" is deemed to be at unity. Based on the COSA results, all rate classes except Rate Schedule 6 (113 per cent) and Rate Schedules 5/25 (111 per cent) fall within the 90 percent to 110 percent range. The FEU believe that neither of these rates are sufficiently far enough outside the range of reasonableness to require any rebalancing at this time.

1.9 Stakeholder Engagement

The stakeholder engagement for this Application included communication and consultation with a broad range of stakeholders through a variety of activities. Through activities such as stakeholder meetings, public information sessions, market research, bill inserts, web, media outreach and customer letters, stakeholders have been and will continue to be appropriately notified, consulted and sufficiently informed of the impact of common rates. Feedback obtained through the consultation process has been reviewed and incorporated into the Application where appropriate.

1.10 Conclusion

The FEU are applying to amalgamate and implement postage stamp rates. Postage stamp rates will be equitable for all customers and eliminate the rate discrepancies across the FEU service areas. Postage stamp rates will result in rate reductions to FEVI and FEW and long-term rate stability to FEVI, FEW and Fort Nelson. Amalgamation and postage stamp rates will also facilitate customer access to all natural gas services and realize the last remaining efficiencies to be gained from common ownership. The FEU have proposed rates for the Amalgamated Entity based on the cost of service of the existing utilities, adjusted for the effects of amalgamation. The rate design employed is based on FEI rate structures and a COSA study

[15] Including the cost of gas.

endorsed by a third-party rate design expert. Based on the evidence in this Application, the FEU submit that the proposed amalgamation is beneficial in the public interest and its proposed rates are just and reasonable and should be approved by the Commission.

2 INTRODUCTION: APPROVALS SOUGHT, REGULATORY PROCESS AND APPLICATION ORGANIZATION

FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEW") (together referred to as the "FortisBC Energy Utilities", the "FEU" or the "Companies"), are applying to the British Columbia Utilities Commission (the "Commission" or "BCUC") for the necessary approvals pursuant to the *Utilities Commission Act* (the "UCA" or the "Act") to amalgamate FEI, FEVI and FEW, as well as Terasen Gas Holdings Inc. ("THI"), into a single entity and implement common rates and services across their service territories starting January 1, 2014. The single amalgamated entity which the FEU are seeking to form will be referred to interchangeably in this Application as "FEI Amalco" or the "Amalgamated Entity". Common rates may also be referred to as postage stamp rates.

2.1 The Approvals Sought

The approvals sought in this Application fall into two categories:

- Approvals required to amalgamate the FEU and THI pursuant to section 53 of the Act; and
- Approvals required to adopt common rates for the Amalgamated Entity pursuant to sections 59 to 61 of the Act.

These approvals are closely interrelated, as the Companies are only pursuing amalgamation in order to implement common rates. The FEU propose to amalgamate and adopt common rates effective January 1, 2014.

A Draft Form of Order setting out the detailed approvals sought has been included as Appendix K-2. The draft order includes cross references to particular sections of the Application where the request is discussed.

The two categories of approval sought are discussed below.

2.1.1 APPROVALS REQUIRED TO AMALGAMATE UNDER THE UCA

The FEU currently consist of three corporations: FEI, FEVI and FEW. The FEU are seeking approval to amalgamate these three companies into one corporation, which would retain the name FEI.

As part of the amalgamation process, the FEU are proposing to simplify the ownership structure of the Amalgamated Entity by amalgamating the FEU with THI. THI is not a public utility, it has no employees and its sole asset is an approximate 19% interest in FEI. While originally set up as part of the financing arrangements for the Southern Crossing Pipeline ("SCP") Project, the existence of THI no longer provides any benefits to FEI, ratepayers or its shareholder. The sole effect of amalgamation with THI would be that THI would, in effect, cease to exist and its shares of FEI would be cancelled.

As FEI, FEVI and FEW are public utilities regulated under the UCA, an amalgamation of the four corporations is subject to section 53 of the UCA. Section 53 of the UCA outlines the process to be followed in order for the FEU to receive approval for an amalgamation. There are four steps involved:

- First, as stated in section 53(3), an application to the Commission must be made for the consent of the Lieutenant Governor in Council (the "LGIC");
- Second, under section 53(4) of the Act, the Commission must inquire into the application for amalgamation and consider whether the amalgamation would be beneficial in the public interest;
- Third, if the Commission determines that the amalgamation would be beneficial in the public interest, section 53(5) of the Act requires the Commission to submit a report and its findings to the LGIC; and
- Finally, the LGIC considers the report and findings of the Commission in determining whether to issue an order consenting to the amalgamation.

The FEU are therefore applying to the Commission in accordance with section 53(3) of the UCA for the consent of the LGIC to amalgamate the FEU. The FEU are requesting that the Commission find that amalgamation of the FEU is beneficial in the public interest and submit a report of its findings to the LGIC as set out in section 53(4).

The rationale for amalgamation is entirely dependent on the adoption of postage stamp rates for the Amalgamated Entity for delivery, midstream and commodity rates. The request to adopt common rates is discussed further below.

2.1.2 COMMON (OR POSTAGE STAMP) RATES AND REGIONAL RATES

The FEU are seeking approvals to implement common or postage stamp delivery, midstream and commodity rates for the Amalgamated Entity which will eliminate the existing rate discrepancies across the regions served by the FEU. Common rates provide a fair and equitable approach for all customers of the FEU going forward by eliminating the complexity and rate disparity that currently exists. This approach is consistent with the electric utilities in the Province, including British Columbia Hydro and Power Authority ("BC Hydro") and FortisBC Inc. ("FBC").

In order to implement common rates the FEU are seeking the following effective January 1, 2014, subject to the approval of the amalgamation by the LGIC:

1. Approval of the discontinuance of the energy, delivery, and commodity rates of FEVI, FEW and FEI's service area of Fort Nelson, not including special contracts and tariff supplements individually approved by the Commission.
2. Approval of the amended FEI rate schedules for the Amalgamated Entity as set out in Appendix B-2.

3. Approval of the FEI Amalco delivery rates as set out in Appendix J-3 on an interim basis, to be applicable to all customers of the Amalgamated Entity as described in Section 7.2 of the Application. The interim delivery rates are to be updated by the results of the Commission's Generic Cost of Capital Proceeding, any other proceeding dealing with the equity risk premium for the Amalgamated Entity and with the 2014 revenue requirements of the Amalgamated Entity in accordance with the rate design described in Section 9 of the Application.

4. Approval of the use of a combined gas portfolio for FEI Amalco as described in Section 7.4.3 of the Application and the gas supply cost allocation methodology for rate setting purposes as described in Section 9.3.4 of the Application, with commodity and midstream rates effective January 1, 2014 for the Amalgamated Entity to be determined by the Commission as part of a future gas cost filing.

5. Approval of the phase-in of the amalgamation-related rate increases for Fort Nelson customers over 15 years as described in Section 8.4.1.1 of the Application.

6. Approval of the discontinuance of FEVI's, FEW's and FEI's service area of Fort Nelson's existing terms and conditions of service and approval of the amendments to FEI's GT&Cs to be applicable to the Amalgamated Entity, as set out in Appendices B-1 and B-2, with deferral of extension of the Customer Choice Program pending a further application by the Amalgamation Entity.

7. Approval of the service agreements with the Vancouver Island Gas Joint Venture and BC Hydro as set out in Appendices E-18 and E-19.

8. Approval of the use of the FEI and FEVI MX Test for FEI Amalco as described in Section 7.4.2.3 of the Application.

9. Approval of the Rate Stabilization Deferral Account ("RSDA") Rider, to permit the distribution of the balance in the RSDA to non-bypass customers in the current FEI service area as described in Section 8.4.1.3 of the Application.

10. Approval of continuation or merger of approved deferral accounts for the FEU and approval of the 4 new deferral accounts as described in section 8.2.1.2 of the Application.

11. Approval of the discontinuance of the Corporate Services Agreement between FortisBC Holdings Inc. and each of FEVI and FEW, leaving the agreement with FEI to remain in place for the Amalgamated Entity as amended to include FEVI and FEW costs as set out in Appendix F.

12. Approval of the adoption of FEI's Transfer Pricing Policy and Code of Conduct, as approved by the Commission in Letter L-64-1997, as the Transfer Pricing Policy and Code of Conduct of the Amalgamated Entity.

13. Approval of the adjustment of the conditions specified in the Commission Order No. G-49-07 relating to the acquisition of Terasen Inc. (now FortisBC Holdings Inc.) by Fortis Inc. as necessary to reflect the amalgamation of the FEU.

Please also see the Draft Order attached as Appendix K-2, which sets out in detail the orders sought in this Application.

2.2 Introduction to Common Rates

As discussed above, this Application primarily concerns the FEU's proposal to implement common or postage stamp rates, which can be contrasted with regional rates. As this distinction is important to understanding the purpose of this Application, a description of each of these rate forms is provided below:

- Common or postage stamp rates treat all customers in the same manner by applying uniform rates to all customers within a respective rate class based on the total cost of the system irrespective of where the customer is located within the service area. For example, each of FEVI and FEW currently offer postage stamp rates within their respective service territory. Although Fort Nelson has retained its own regional rate structure, FEI offers postage stamp rates across its other service areas with all approximately 850,000 customers of the FEI in the Lower Mainland, Interior and Columbia regions paying the same delivery rates[16] within their class of service regardless of where they take service. In this Application, the request to implement postage stamp or common rates refers to charging uniform rates to all customers within a given rate class across all of the service areas of the FEU.

- Regional rates imply that rates differ for each rate class depending on where customers are located in a service area. With regional rates, for example, customers may be allocated a cost of service unique to their respective region, with localized factors such as customer base, consumption patterns, location, timing of connection and geographical terrain accounting for differences in the cost of serving each customer across regions. A conceptual issue associated with regional rates is defining the appropriate level of locational granularity, since each customer on the system theoretically has a different cost of service based on the customer's unique location on the system. According to EES Consulting Inc., "*the question then becomes how far to carry the averaging of costs between customers on the basis of location…[as]… it would be impossible to set separate rates for each individual customer.*"[17]

As described in section 3 of the Application, this conceptual issue with regional rates has been addressed to date within the FEU simply by using the regional distinctions of the service areas of the predecessor companies to the FEU. The three separate companies, four distinct rate bases and six service areas that make up the FEU today are an artefact of the FEU's growth by acquisition. In their report, EES Consulting recognizes that "*the current regional differences in delivery rates… [for the FEU]…do not necessarily reflect the same regional separation that*

[16] The Columbia service area has had the same delivery rates as the Lower Mainland and Inland service areas since January 1, 1994. Refer to Section 9.3.2.2 for a discussion on how delivery rates for Lower Mainland, Inland and Columbia have been set historically.

[17] Appendix D-1, EES Consulting, "FEU Natural Gas Cost of Service Review", March 2012, p.5.

would occur based on operating and cost differences alone."[18] The end result is rate disparity across the areas served by the FEU that is based more on history rather than necessarily being based on cost of service.

The proposal in this Application is to bring an end to this disparity and implement common delivery, midstream and commodity rates across all of the FEU's service territories. Sections 7, 8 and 9 of this Application provide details on the FEU's proposed common rates and rate design for the Amalgamated Entity.

2.3 Timing of Request to Implement Common Rates

During consultation on this Application, stakeholders have asked why the FEU are seeking to implement common rates now and why it was not done sooner. Amalgamation has only been a practical possibility since the FEU have been under common ownership, which occurred in 2002. (Section 3 of this Application provides a brief history of each of the utilities making up the FEU.) While common rates have always been preferred by the FEU, the present time is opportune to implement them due to the circumstances of FEVI and FEW. As discussed more fully in section 3, since 1996 the rates for FEVI have been governed by the Vancouver Island Natural Gas Pipeline Act ("VINGPA") and VINGPA Special Direction which were designed to assist the financial viability of the Vancouver Island system. While this structure was in place, it would not have been appropriate to amalgamate. By 2002, FEVI had accumulated a large revenue deficiency in a deferral account authorized by the VINGPA Special Direction. Since 2002, FEVI has sought to bring down the balance in this account and has succeeded in paying off the deficiency and accumulating a revenue surplus. This surplus can now be used to offset the rate impact of amalgamation. In addition, the Royalty Revenues provided by the Province under the VINGPA structure used to mitigate the costs of natural gas have recently ceased. In short, the existing framework governing the rates of FEVI for the past 16 years have come to an end and FEVI has been left in a favourable position to amalgamate with the FEI and FEW. At the same time, FEW has now been converted from a propane to natural gas system, facilitating the adoption of common delivery, midstream and commodity rates.

It is therefore an opportune time for the FEU to amalgamate and implement common rates for all customers of the FEU across the Province.

2.4 Implementation of Common Rates and Amalgamation

The FEU are proposing to amalgamate and implement common rates as of January 1, 2014.

As described above, before the FEU amalgamate, the Commission must find that amalgamation is beneficial in the public interest and the LGIC must consent to the amalgamation. Once these approvals are received, the FEU require further time before it can implement common rates,

[18] Ibid p.8

including time to legally amalgamate under the Business Corporation Act, update its financing arrangements, notify customers of the change in rates and make adjustments to its billing systems.

Given the timing of this Application a timely decision will be required to meet the January 1, 2014 effective date in order to provide sufficient time to prepare for the implementation of common rates, including providing notification to customers of the change.

2.5 Rationale for Proposing Delivery Rates on an Interim Basis

The FEU are seeking approval of delivery rates for the Amalgamated Entity using the 2013 cost of service to be implemented on January 1, 2014 on an interim basis. This section explains the rationale for the request.

Section 8 of the Application discusses the impact of amalgamation on the cost of service of the FEU, including the impact on gas costs, operating and maintenance expense, depreciation and amortization expense, income tax, other revenue and rate base. As described in Section 8 of the Application, the proposed common delivery rates are based on the applied-for 2013 cost of service of the individual utilities with the necessary adjustments due to the effects of amalgamation. As also discussed in section 8, the proposed common delivery rates are also based on a return on equity for the Amalgamated Entity assuming the benchmark that is in effect at the time of filing. Given these factors, the proposed rates will need to be updated to reflect 2014 delivery revenue requirements, the fourth quarter 2013 gas cost filing, and the outcome of the Commission's Generic Cost of Capital proceeding (the "GCOC Proceeding"). These three required updates are discussed further below.

First, the FEU plan to file a revenue requirement application in 2013 seeking approval for 2014 rates. If amalgamation and common rates are approved, this revenue requirements application would seek approval for common rates reflecting the forecast 2014 revenue requirements of the Amalgamated Entity. As discussed below, a timely decision in the present proceeding would allow for one application for one legal entity and facilitate a more efficient application process for 2014 rates.

Second, if amalgamation is approved, FEI Amalco will make a fourth quarter 2013 gas cost filing in the same manner as presently performed by FEI. Through this filing, the Commission can approve the gas costs (commodity and midstream) for the Amalgamated Entity beginning January 1, 2014.

Third, the Commission has initiated the GCOC Proceeding by Order No. G-20-12. Among other things, the GCOC Proceeding will review (a) the setting of the appropriate cost of capital for a benchmark low-risk utility, (b) the possible return to an ROE Automatic Adjustment Mechanism ("AAM") for setting an ROE for the benchmark low risk utility, and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third-party debt.[19] It is the Companies' understanding that the GCOC Proceeding will establish a benchmark ROE based on a benchmark utility effective January 1, 2013 to December 31, 2013, for the initial transition year. The GCOC Proceeding will make determinations as to the characteristics of the benchmark utility and possibly identify which utility, if any, is the appropriate benchmark utility in BC. The preliminary scoping document for the GCOC Proceeding (Order No. G-20-12) also contemplates that the individual utilities' risk premiums will be set in a separate future proceeding or a future Multi-Utility Cost of Capital proceeding.

While the impact of amalgamation can be fully canvassed in this Application, if amalgamation is approved, the delivery rates sought in this Application will be superseded by the rates sought in the 2014 revenue requirements application for the Amalgamated Entity to be filed in 2013 and the fourth quarter 2013 gas cost filing, and rate adjustments to reflect the results of the GCOC Proceeding and any related subsequent proceeding. It is nonetheless essential to have a rate approved for the Amalgamated Entity upon amalgamation on January 1, 2014 so that there is a rate in place for the Amalgamated Entity pending the updates as discussed above. Having rates for January 1, 2014 based on 2013 costs is also important to provide, in effect, a 2013 approved rate for the Amalgamated Entity which the 2014 revenue requirement application can use as a comparator for the proposed 2014 final rates.

2.6 Anticipated Evidentiary Update due to Decision on the FEU's 2012-2013 RRA

At the time of filing, the FEU are awaiting a decision from the Commission on the FEU's 2012-2013 Revenue Requirements and Rates Application (the "2012-2013 RRA"). The FEU anticipate that the Commission will likely render its decision on the 2012-2013 RRA during the regulatory process for this Application.

The common rates proposed for the Amalgamated Entity in this Application are based on the FEU's 2013 revenue requirements as applied for in the FEU's 2012-2013 RRA. Consequently, the Commission's decision on that application may have an impact on the amalgamated cost of service filed within this Application that will have flow-through effects to the COSA models, bill impact tables/schedules and proposed interim rates. If so, the FEU anticipate filing an evidentiary update in this proceeding following a decision on the 2012-2013 RRA to update the amalgamated cost of service, COSA models' results, bill impact tables/schedules and proposed interim rates.

2.7 Proposed Regulatory Process

The FEU believe that this Application can be addressed efficiently and effectively by a written hearing process for the following reasons:

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[19] BCUC Order No. G-20-12

- The FEU have consulted with respect to the Application as described in section 10 of the Application.
- The rationale for amalgamation and common rates can be fully canvassed through a written proceeding.
- The relevant facts, such as the impacts of implementing common rates, are clear and should not be contentious.
- The cost of service on which the proposed common rates are based has been fully canvassed in the 2012-2013 RRA, which included an oral hearing phase. Costs from amalgamation are proposed to be captured in a deferral account and, as common rates are proposed to be implemented as of January 1, 2014, any savings will be considered in the 2014 and future revenue requirement applications.
- Incremental changes in rate design for the Amalgamated Entity involve technical issues that lend themselves to a written process.

The FEU suggest that the determination of the appropriate hearing process should be made after the first round of IRs at the latest.

The FEU propose the following draft regulatory timetable, which provides dates with and without Intervener evidence for a written process. In all cases, the timetable acknowledges the workload required by the Commission and all parties in this and other proceedings. A draft procedural order has been provided in Appendix K-1.

ACTION	DATE (2012)
Publication of Notice	Monday, April 23
Workshop (commencing at 9:00 am)	Monday, April 30
Commission Information Request No. 1 to FEU	Monday, May 07
Intervener Information Request No. 1 to FEU	Friday, May 11
FEU Response to Information Requests No. 1	Friday, June 01
Procedural Conference (Timetable and Process - commencing at 9:00 am)	Wednesday, June 06
Commission Information Request No. 2 to FEU	Thursday, June 21
Intervener Information Request No. 2 to FEU	Thursday, June 21
FEU Response to Information Requests No. 2	Thursday, July 12
TIMETABLE – NO INTERVENER EVIDENCE	
FEU Final Argument Submissions	Thursday, August 02
Intervener Final Argument Submissions	Thursday, August 23
FEU Reply Argument Submissions	Thursday, September 06
TIMETABLE – WITH INTERVENER EVIDENCE (if required)	
Intervener Evidence Filed	Thursday, July 12
BCUC IRs to Interveners	Thursday, August 02
FEU IRs to Interveners	Thursday, August 09
Intervener Response to IRs	Thursday, August 23
FEU Final Argument	Thursday, September 13
Intervener Final Argument	Thursday, October 04
FEU Response Argument	Thursday, October 25

The Companies respectfully request that a decision on this Application be made prior to **December 28, 2012**. There are several reasons for this request:

- Firstly, the Companies anticipate filing a revenue requirement application(s) in the first half of 2013 for approval of 2014 rates. In order for the Companies to prepare the appropriate application(s) and associated financial schedules (e.g., individual entities versus amalgamated entity), a determination is required as soon as possible. Significant efficiency can be gained by FEU staff and interveners if the revenue requirement application can be filed knowing if amalgamation and common rates will proceed or not.
- Secondly, if the amalgamation and common rate proposals are approved, sufficient time is required to allow for the Companies to implement the orders, including amalgamation

under the BCA, communication of the rate changes and associated changes to bill layouts to customers and developing, building, testing and implementing system changes in a timely fashion without impacting customers (i.e., allowing the required rate changes to be reflected in the billing systems for January 1, 2014).

- Thirdly, once the Commission renders its decision, if the Commission finds that amalgamation is beneficial in the public interest, the findings regarding the proposed amalgamation must still be provided to the LGIC for its consent to the amalgamation. There is some uncertainty regarding how long that process will take, thus making it important to provide as much lead time as possible before the proposed implementation date of January 1, 2014.

The FEU look forward to working with the Commission and Interveners towards an efficient review of this Application.

2.8 Organization of the Application

The Application has been organized to address the major components of the Approvals Sought, namely, amalgamation of the FEU, and the rate design for the Amalgamated Entity:

- **Section 1:** Executive Summary
- **Section 2:** Introduction: Approvals Sought, Regulatory Process and Application Organization
- **Section 3:** Overview of the FortisBC Energy Utilities – Demonstrates how the current operating areas and utilities are the product of growth by acquisition and provides an overview of the revenue requirements and current key operating data for each of the utilities today
- **Section 4:** Operating Context and Issues Addressed by this Application – Provides contextual information on energy policy and customers' uses of energy and their changing requirements and defines the problem that the FEU are seeking to address in this Application
- **Section 5:** Review of Options – Explains the five step process the FEU undertook to review potential alternatives to the FEU preferred solution
- **Section 6:** The Selected Option: Common Rates Achieved via Amalgamation are Beneficial in the Public Interest – Discusses why amalgamation to permit the adoption of common rates is the appropriate approach and is beneficial in the public interest

- **Section 7:** Implementation of Common Rates – Explains the test that must be applied by the Commission in reviewing this Application, and the legal and operational effects of amalgamation

- **Section 8:** Overview of Proposed Common Rates of the Amalgamated Entity – Provides an overview of the revenue requirements, capital structure and return on equity for the Amalgamated Entity; and the 2014 common rates

- **Section 9:** Rate Design – Describes why the rate design is just and reasonable and an appropriate basis for common rates for the Amalgamated Entity

- **Section 10:** Stakeholder Engagement – Describes the Companies' communications with stakeholders prior to submission of the Application and planned communications following submission

3 OVERVIEW OF THE FORTISBC ENERGY UTILITIES

This section provides a review of the FEU's current and historical corporate structure and a financial overview of each of the utilities. As discussed below, the FEU's current corporate and rate structures are a result of the FEU's growth via acquisition, with service regions retaining historical regulatory structures set by each predecessor company. The result is three legal entities, with four rate bases and six service areas. Despite this diversity, the FEU have become functionally integrated, achieving cost savings for all customers. For the reasons discussed in section 2, it is now the appropriate time to amalgamate the FEU, and bring simplification, harmonization and additional efficiencies to the complex set of structures that currently comprise the FEU.

This section is organized as follows:

- Section 3.1 provides an overview of the current corporate structure of the FEU.
- Section 3.2 provides a brief corporate history of FEI and its rate structures and a financial overview of the utility, including the Fort Nelson service area.
- Section 3.3 provides an overview of FEVI.
- Section 3.4 provides an overview of FEW.
- Section 3.5 provides a description of the Utilities Strategy Project, which functionally integrated the FEU.
- Section 3.6 is a summary of this section.

3.1 Current Corporate Structure of the FEU

The FEU combined, provide sales and transportation services to residential, commercial, and industrial customers in approximately 140 communities, currently serving approximately 956,000[20] customers throughout the Province.[21] The FEU own and operate natural gas pipelines and natural gas distribution facilities in BC, including approximately 46,000 kilometres of transmission pipelines and distribution mains. The FEU's distribution network serves approximately 95 percent of natural gas customers in BC and delivers more than 20 percent of the total energy consumed in the Province.

The FEU consist of three legal entities: FEI, FEVI and FEW. While FEVI and FEW each represent a single service area, FEI is comprised of four service areas, the Lower Mainland, Inland, Columbia and Fort Nelson, for a total of six service areas served by the FEU across the Province. Although not a separate legal entity, Fort Nelson has historically had its own rate base for the purposes of determining rates. Therefore FEI has been divided into two rate

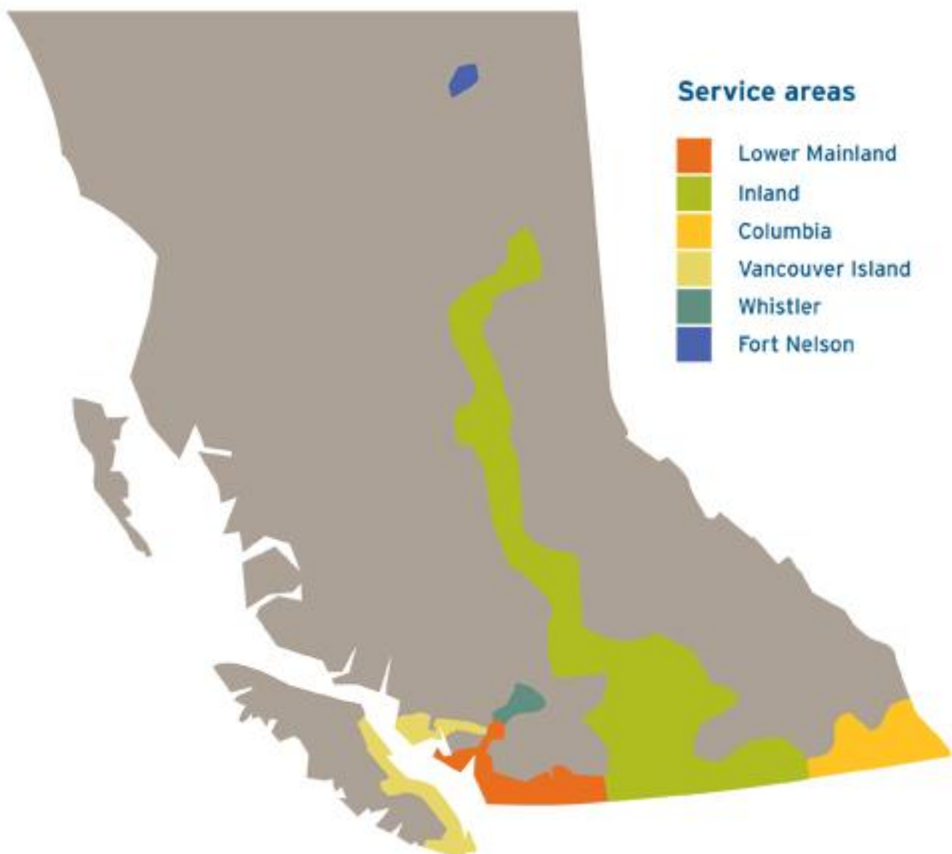
[20] FEU Gas Sales Statistics for BCUC 2011/12 Annual Report to the Legislature

[21] As a significant number of these customers consist of multiple family members, the population served is much larger than 956,000.

bases: one for Fort Nelson and one for the Lower Mainland, Inland, and Columbia service areas. Thus, although there are only three legal entities, there are four rate bases and six service areas.

The following map provides an illustration of FEU's six service areas:

Figure 3-1: FEU Service Areas



References to "Fort Nelson" or "FEFN" refer to the Fort Nelson service area of FEI. References to "FEI (Mainland)" or "Mainland" refer to the Lower Mainland, Inland and Columbia service areas of FEI. The Inland service area encompasses the Interior region of BC, while the Columbia service area serves the Kootenay region.

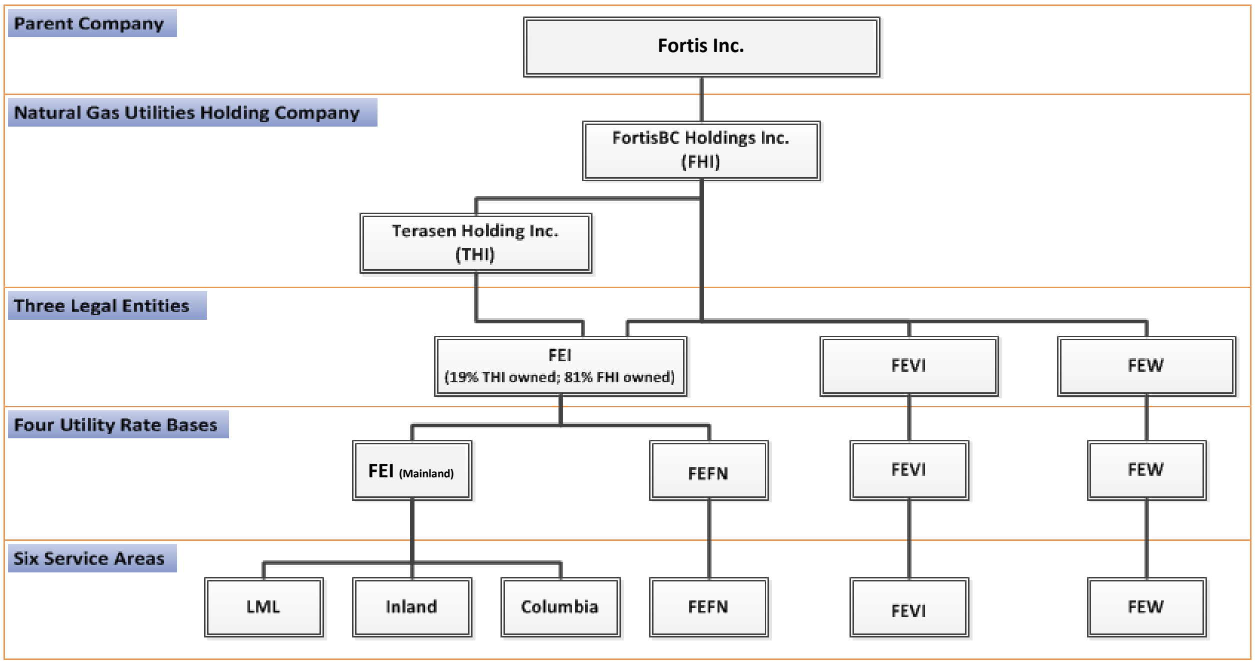
FEVI and FEW are wholly-owned subsidiaries of FortisBC Holdings Inc.[22] ("FHI"). Eighty-one percent of FEI is owned by FortisBC Holdings Inc. and 19% by Terasen Gas Holdings Inc., while 100% of Terasen Gas Holdings Inc. is owned by FortisBC Holdings Inc. (As discussed in section 7.3, Terasen Gas Holdings Inc. was originally set up as part of the financing

22 Formerly Terasen Inc. and BC Gas Inc. prior.

arrangements of the Southern Crossing Pipeline Project; however, since it no longer serves any purpose, the FEU are proposing in this application to amalgamate it with the FEU.)

FortisBC Holdings Inc. is a wholly-owned subsidiary of Fortis Inc. The figure below illustrates how the FEU fit within the overall Fortis Inc. corporate structure, and also depicts the rate bases and service areas for each legal entity.

Figure 3-2: Corporate Structure



3.2 FortisBC Energy Inc.

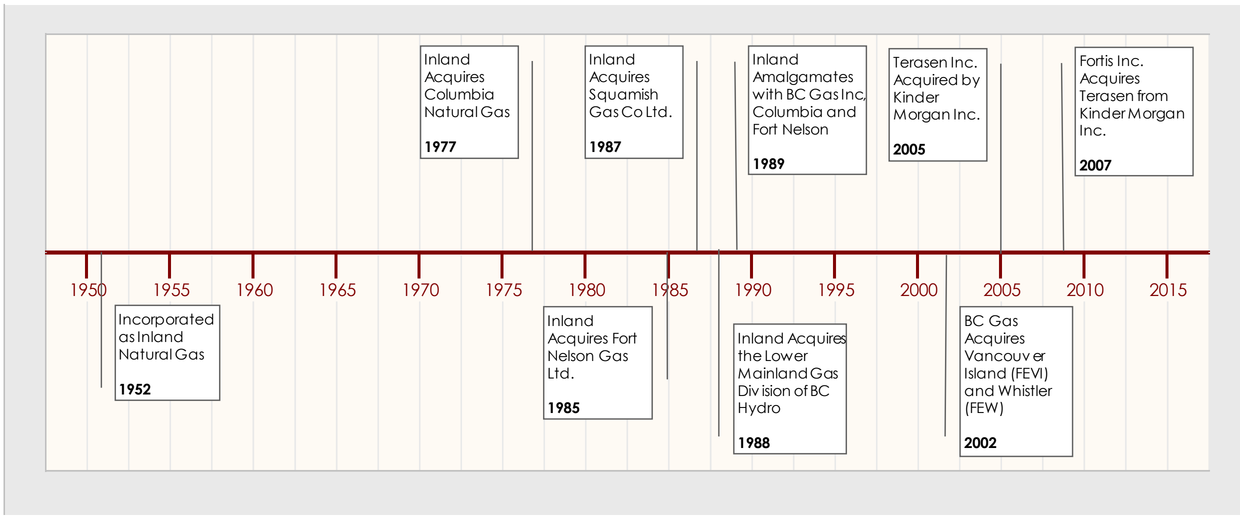
FEI[23] currently provides natural gas transmission and distribution services to approximately 850,000[24] residential, commercial, and industrial customers in more than 100 communities in the Lower Mainland, Inland, Columbia, and Fort Nelson service areas. Service is provided through approximately 40,000 kilometres of distribution mains and transmission pipelines.

3.2.1 CORPORATE HISTORY OF FEI (INCLUDING FORT NELSON SERVICE AREA)

The figure below illustrates the evolution of FEI culminating in the corporate structure that exists today.

[23] Formerly Terasen Gas Inc.
[24] FEU Gas Sales Statistics for BCUC 2011/12 Annual Report to the Legislature

Figure 3-3: Key Corporate Highlights



3.2.1.1 Acquisitions by Inland Natural Gas Co. Ltd.

The utility was first incorporated in 1952 as Inland Natural Gas Co. Ltd. ("Inland"), distributing natural gas throughout the BC interior. Inland subsequently grew through a series of acquisitions.

In the 1950s, Inland purchased several subsidiaries, including St. John Oil and Gas, Peace River Transmission, Canadian Northern Oil and Gas, and Grand Prairie Transmission. In 1977, Inland purchased Columbia Natural Gas in the East Kootenays, which positioned Inland as the major distributor of natural gas for most of the BC Interior. In 1985 Inland acquired Fort Nelson Gas Ltd., the owner of the gas distribution system in and around Fort Nelson, from Colonial Oil and Gas Limited. In 1987, Inland purchased Squamish Gas Co. Ltd. from Superior Propane Ltd.

In 1988, the Lower Mainland Gas Division of BC Hydro was purchased by Inland.

A new company, BC Gas Inc., was created in 1989 to amalgamate the divisions of Lower Mainland Gas, Inland, Columbia and Fort Nelson. All of these divisions, except Lower Mainland Gas, had previously been separate legal entities.

In 1990, BC Gas Inc. commenced construction, operation and maintenance of a piped propane distribution system to serve residential and commercial customers in Revelstoke. Today, propane is transported to Revelstoke by railcar and tanker-truck and off-loaded at an above-ground site. The propane is vaporized at the above-ground site and then distributed through underground gas lines, serving approximately 1,600 residential and commercial customers. The costs of the Revelstoke distribution system are included as a component of FEI's rate base.

In 1993 BC Gas Inc. changed its name to BC Gas Utility Ltd. and a holding company that held all of the shares of BC Gas Utility Ltd. was named BC Gas Inc. That same year, through Order

No. G-68-93, the Commission approved the consolidation of the Lower Mainland, Inland and Columbia divisions for regulatory purposes.

In 2002, BC Gas Inc. purchased Centra Gas BC Inc. (now FEVI) and Centra Gas Whistler Inc. (now FEW), adding natural gas customers on the Sunshine Coast and Vancouver Island and piped propane customers in Whistler. In 2003, BC Gas Inc. changed the name of each of its corporate entities, with BC Gas Inc. becoming Terasen Inc. (the holding company of the natural gas utilities), BC Gas Utility Ltd. becoming Terasen Gas Inc. ("TGI"), Centra Gas becoming Terasen Gas (Vancouver Island) Inc., Centra Gas Whistler Inc. becoming Terasen Gas (Whistler) Inc. and Squamish Gas Co. Ltd. becoming Terasen Gas (Squamish) Inc. ("TGS").

In 2005, Terasen Inc. (the holding company of the natural gas utilities) was acquired by Kinder Morgan Inc., a U.S. based energy storage and transportation company. In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc., and on March 1, 2011, the Terasen group of companies were renamed - Terasen Inc. became FortisBC Holdings Inc., Terasen Gas Inc. became FortisBC Energy Inc., Terasen Gas (Vancouver Island) Inc. became FortisBC Energy (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. became FortisBC Energy (Whistler) Inc.

3.2.1.2 Maintenance of Lower Mainland, Inland and Columbia Service Areas

As discussed above, Inland Natural Gas, B.C. Gas Inc., Columbia Natural Gas Ltd. and Fort Nelson Gas amalgamated in 1989.

In 1991, FEI proposed and the Commission approved a gas cost allocation methodology that streamed the gas supply and upstream pipeline and storage costs to the three regions (Lower Mainland, Inland and Columbia) that made up FEI at the time. An account called the Gas Cost Reconciliation Account ("GCRA") captured all gas costs. FEI also proposed, and the Commission approved, regional gas cost allocation and rates, which maintained the structure of the predecessor companies. The resulting gas cost rates were only slightly different among the three regions.[25]

In 1993, FEI undertook a delivery rate design application where it proposed postage stamp delivery charges for the Lower Mainland, Inland and Columbia regions. The Commission approved postage stamp delivery charges for the Inland and Lower Mainland residential, commercial and general firm service customers.[26] Although the Commission declined to include the Columbia region in the postage stamp delivery charges approved for the Mainland and Inland, they did allow the Company to set the same delivery rate for Columbia customers. The delivery charges for the three regions have remained identical since that time.

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[25] Commission Order No. G-22-92, dated February 21, 1992.
[26] Commission Order No. G-101-93, dated October 25, 1993.

FEI did not propose to change the regional structure approved for gas supply and upstream pipeline and storage costs adopted following the 1991 application.

In 2004, at the request of the Commission, the GCRA was separated into two portfolios - the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA") - to facilitate the implementation of the Customer Choice Unbundling program. This program allowed customers to purchase their gas supply through marketing firms. Since that time, the Lower Mainland, Inland and Columbia commodity rates have been postage-stamped, while the midstream rates have maintained slight differences between these regions.

The sequence of applications and approvals has culminated in the rate structure that exists today; identical basic, delivery and commodity charges, with slight variations in the midstream charges. The following table highlights the rates and the rate structure that exists today for the three regions. The rates are effective as at January 1, 2012[27]:

Table 3-1: Lower Mainland, Inland and Columbia Rate Components

Effective January 1, 2012	Lower Mainland	Inland	Columbia
Basic Charge per Day	$0.389	$0.389	$0.389
Delivery Charge per GJ	$3.559	$3.559	$3.559
Commodity Charge per GJ	$4.005	$4.005	$4.005
Midstream Charge per GJ	$1.424	$1.398	$1.433

3.2.1.3 Amalgamation of Squamish and FEI

On October 16, 2006, FEI filed its Advance Annual Review materials in accordance with the 2004-2007 Multi-Year Performance Based Ratemaking ("PBR") Settlement. As a part of the Annual Review, FEI recommended amalgamation between what was then TGI and TGS. The amalgamation was requested to address TGS' increasing financial obligation to the Province of British Columbia.

Prior to 1989, TGS was a piped propane utility serving customers in Squamish. With the arrival of the FEVI High Pressure Transportation System ("HPTS"), TGS customers moved from piped propane to natural gas service.

To encourage customers to switch from propane to natural gas and to encourage customer growth, the Province became a financial partner with TGS, providing support via the Rate Stabilization Facility ("RSF") to record revenue shortfalls and surpluses of TGS. Beginning in 1999, TGS faced upward commodity cost pressure, which resulted in a significant increase in the annual RSF funding requirements from the Province.

27 As shown in the FEI Q4 Gas Cost Report filed Nov. 18, 2011

In 2006 the Province agreed on a process to resolve the financial obligations between TGS and the Province. As part of the resolution of the financial obligations, TGI was to amalgamate with TGS, effective January 1, 2007.

In regards to the amalgamation with TGS, the Lieutenant Governor in Council issued Order in Council ("OIC") No. 766, OIC No. 767, OIC No. 768 and Vancouver Island Natural Gas Pipeline Special Direction No. 3 ("SD No. 3") to the Commission on November 2, 2006. SD No. 3 included instructions to the Commission regarding the determination of the common equity component and ROE for the amalgamation of TGI and TGS. TGS adopted the rate design and general terms and conditions of TGI, as approved by Order No. G-160-06.

Based on the OIC, TGI requested and received Commission approval of the following by Order No. G-160-06:

- An increase in the common equity component of the TGI capital structure from 35 per cent to 35.01 per cent. This was based on the weighted average of the TGI and TGS equity components;
- An 8.37 per cent return on equity. This was based on the weighted average of the TGI and TGS return on equity components;
- The establishment of a rate base deferral account to record costs related to the amalgamation and variances in operation and maintenance ("O&M") expenses that resulted from the TGI O&M calculation methodology; and
- The area formerly served by TGS to be treated as part of the TGI Lower Mainland Service area and to be subject to the TGI Tariff.

The BCUC agreed that Commission approval was not required for the amalgamation[28] and in 2007 the two entities were amalgamated to operate under the name Terasen Gas Inc.

3.2.1.4 Fort Nelson Service Area ("FEFN")

As discussed above, the natural gas distribution system in the Fort Nelson service area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland and other companies and upon amalgamation continued forward as BC Gas Inc. (now FortisBC Energy Inc.).

Operations in Fort Nelson consist of a transmission lateral from the nearby Westcoast Energy Inc. (part of Spectra Energy) processing plant to the town of Fort Nelson together with a gas distribution system. Also included in the service area is the distribution system in Prophet River.

Although Fort Nelson is legally a part of FEI, Fort Nelson has a separate rate base for the purpose of determining rates. Its rates have historically been set at a level lower than the rest of the FEU. In its 1992 Revenue Requirements Application, BC Gas Utility Ltd. (now FEI) sought

[28] BCUC Order No. G-160-06, December 14, 2006.

consolidation of its four gas divisions, including Fort Nelson. Consolidation was endorsed by independent consultants, who estimated the annual cost savings to be between $500 thousand and $600 thousand.[29]

The matter of consolidation was raised in the Inland and Columbia regions, and there were no customer objections. However, objections were received from the Fort Nelson region. The objections were based on the Fort Nelson region's concern about the lack of consultation regarding the consolidation proposal, as well as the fact that Fort Nelson residents believed that their service area was able to operate as an independent entity with rates being established on a separate and individual basis from the rest of the service areas.

Although the Commission recognized the benefits of the consolidation proposal at that time, Order No. G-63-92 denied the consolidation proposal. In its decision, the Commission stated that "*while the saving is material, the canvassing of the full impact on all customers is more important.*" The Commission deferred a decision on consolidation to the 1993 Phase B Rate Design hearing to allow time to determine the full rate impact of consolidation on all service areas.

FEI decided to exclude Fort Nelson from the 1993 Phase B consolidation and postage stamp proposal. The Fort Nelson service area has therefore remained separate from FEI's general revenue requirement applications and performance based rates.

Today, Fort Nelson is the smallest of the six service areas in terms of sales volumes and number of customers. This region currently serves approximately 2,400[30] customers who consume approximately 6 PJs of natural gas annually.

3.2.2 FINANCIAL OVERVIEW OF FEI (INCLUDING FORT NELSON SERVICE AREA)

As discussed above, although FEI (Mainland)[31] and Fort Nelson are included in the same legal entity, they each have their own cost of service, rate base and rate structures. The total cost of service can be summarized into two main components - the delivery cost of service (or delivery margin) and the cost of gas, each of which is discussed separately below.

3.2.2.1 Delivery Cost of Service

Delivery cost of service is comprised of operating and maintenance costs, property taxes, amortization expense associated with deferral accounts, depreciation expense associated with the recovery of capital investments, financing costs (both debt and equity) as well as income tax expense.[32] Other revenue is also included as an offset to costs.[33] The Mainland delivery cost is

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[29] Commission Order No. G-63-92, dated August 5, 1992

[30] FEU Gas Sales Statistics for BCUC 2011/12 Annual Report to the Legislature

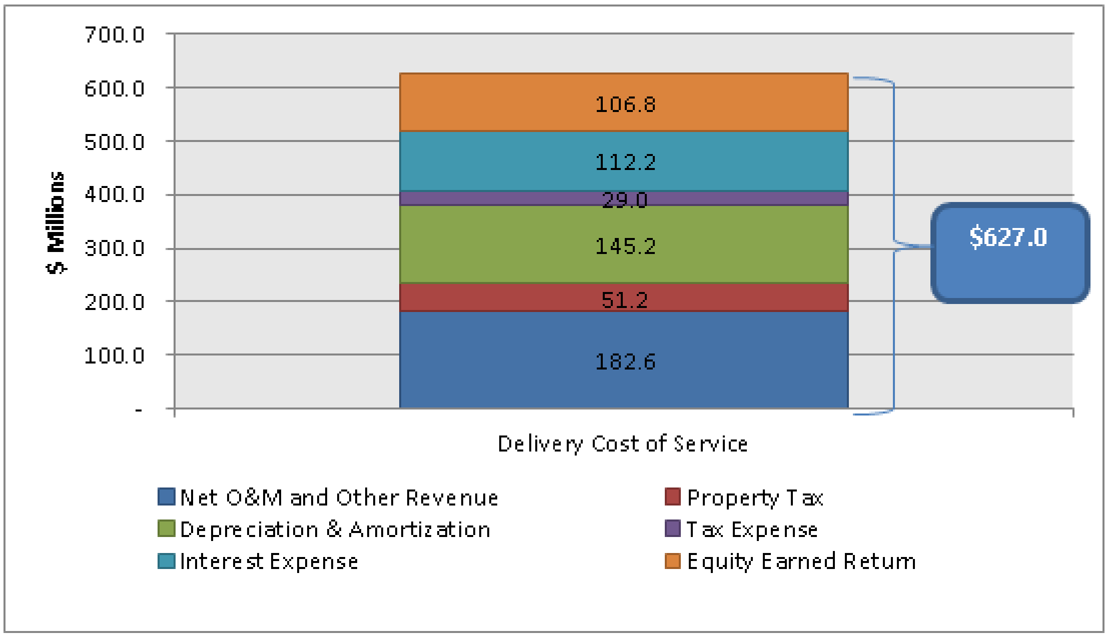
[31] As noted above, references to Mainland or FEI (Mainland) refer to the three service areas of the Lower Mainland, Inland and Columbia.

[32] The FEI removal cost provision is also included in delivery margin and for presentation purposes is combined with depreciation expense on Schedule 6, Column 5, Line 26 of Tab 7.1 in Appendix H-1

recovered through a fixed daily basic charge, a volumetric delivery rate and, for some rate schedules, a demand charge.[34] The Fort Nelson delivery margin is recovered through the variable monthly rate and minimum daily service charges.[35]

The delivery margin to be recovered through 2013 stand-alone delivery rates, as proposed in the FEU's 2012-2013 RRA, is $627.0 million in FEI and $1,926 thousand in FEFN.[36] The details of each element of the delivery costs were reviewed in the 2012-13 RRA and are summarized in Figures 3-4 and 3-5 below.

Figure 3-4: Mainland 2013 Forecast Delivery Cost of Service ($ millions) [37]



33 Other revenue includes revenue from service work (connection charges), late payment charges and returned cheques. For FEI, other revenue also includes revenue for wheeling charges, third party revenue on Southern Crossing Pipeline and revenue from natural gas for transportation service and adjustments for biomethane

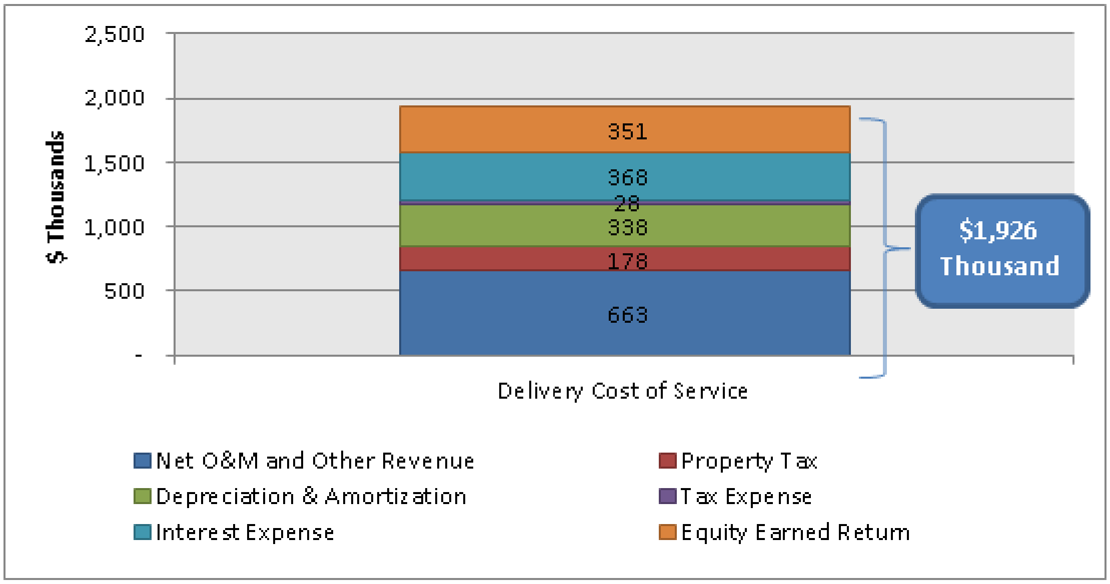
34 For transportation customers an additional administrative charge is also levied

35 Fort Nelson's Rate Schedule 3 has a declining block delivery charge, gas cost recovery and a minimum monthly charge whereas the charges for Rate Schedules 1, 2.1 and 2.2 are burner tip rates. Rate Schedule 25 has a declining block delivery charges plus a monthly administration charge.

36 Appendix H-1, Tab 7.1, Schedule 6, Column 5, Line 22 and, Appendix H-4, Tab 7.4, Schedule 6, Column 5, Line 22

37 Appendix H-1, Tab 7.1, Schedule 6, Column 5. For a breakdown of earned return (interest expense and equity return) please refer to Schedule 81, Column 7.

Figure 3-5: Fort Nelson Forecast 2013 Delivery Cost of Service ($ thousands) [38]



The figures above show that Mainland and Fort Nelson have similar overall delivery cost profiles in that operating and maintenance, depreciation and amortization and interest expense form the largest components of the delivery margin.

The current capital structure and return on equity, as approved through BCUC Order No. G-158-09, is reflected in the stand-alone FEI and FEFN delivery cost of service.

3.2.2.2 Cost of Gas

The cost of gas is comprised of the forecast natural gas cost for FEI Mainland and FEFN and propane commodity costs for Revelstoke. This includes hedging, and forecast costs for midstream resources.[39] A single portfolio is used to manage the cost of gas for FEI and Whistler, resulting in the same unit gas cost recovery charges applicable to sales customers in these regions.[40]

Consistent with existing Commission guidelines, the FEI gas cost (CCRA and MCRA) deferral account balances are reported and reviewed on a quarterly basis. The commodity and midstream rates are subject to quarterly review; the commodity cost recovery rate is subject to

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38 Appendix H-4, Tab 7.4, Schedule 6, Column 5. Please note that Other Revenue includes the 2012 Revenue Surplus of $(97) thousand. For a breakdown of earned return (interest expense and equity return) please refer to Schedule 81, Column 6.

39 Midstream resources include the contracted transmission pipeline and storage capacity, and balancing and peaking gas required to support the annual load and manage load variability. As well, the forecast midstream costs include revenues from mitigation activities.

40 Midstream recovery charges vary amongst sales customers. The Lower Mainland Rate 3 midstream recovery charge is applied to FEW sales customers in addition to the Commodity Cost Recovery Charge to form the total Gas Cost Recovery Charge applied to FEW sales customers.

quarterly flow through adjustment while, under normal circumstances, the midstream cost recovery rates are adjusted on an annual basis with a January 1 effective date.

The Fourth Quarter 2011 gas cost forecasts have been used in analyzing rates for both the individual service areas, and the Amalgamated Entity. The changes to the forecast gas costs used in the 2012-2013 RRA to the updated forecast gas costs used in the 2013 test year within this Application do not materially affect the calculations related to working capital within the revenue requirements models.

There have been some minor adjustments (which are described in Section 8.1.1.1) between the delivery cost of service and the cost of gas components of the amalgamated cost of service to ensure consistency between the service areas. As described in Section 8.1.1.1, the FEVI company use gas, unaccounted for gas and gas control management were moved from gas costs to O&M to align the treatment of these items with the current FEI treatment.

The 2013 cost of gas, as reflected in the 2012-2013 RRA, is $658.6 million in FEI and $2,945 thousand in FEFN and was based on the Commission approved gas cost recovery rates effective January 1, 2011.[41] For the purposes of updating the COSA studies that are included in this Application, the forecast 2013 cost of gas and corresponding offsetting revenues have been updated to $544.1 million in FEI and $2,461 thousand in FEFN, based on the five-day average of the November 1, 2, 3, 4, and 7, 2011 forward prices, and which reflect the forward prices utilized in FEI's 2011 Fourth Quarter Gas Cost report[42].

On March 1, 2012, FEI filed the First Quarter 2012 Gas Cost Report, indicating a decrease in the commodity cost recovery charge was required. A decrease of $1.028 per GJ was proposed and approved by the BCUC[43], lowering the commodity charge from $4.005 to $2.977 per GJ, effective April 1, 2012.

The commodity charge is a flow-through charge; it is recovered from customers at cost. Therefore a change in the commodity charge will not impact the rate changes proposed in this application. It is appropriate to use the Fourth Quarter 2011 gas cost forecasts for determining rates.

3.2.2.3 Rate Base

The rate base is comprised of mid-year net plant in-service (gross plant in-service, less contributions in aid of construction, less accumulated depreciation relating to both, and negative salvage) and is 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

41 Appendix H-1, Tab 7.1, Schedule 13, Column 10, Line 33; Appendix H-4, Tab 7.4, Schedule 13, Column 10, Line 13; those cost of gas rates remained in place for FEI through June 30, 2011 and for Fort Nelson through September 30, 2011.

42 Appendix H-5, Schedule 1, Rows 4 and 9; Appendix H-11, Schedule 1, Rows 4 and 9

43 Commission Order No. G-26-12, dated March 9, 2012.

cash working capital and other working capital; mid-year future income tax asset and offsetting liability; and in the case of the Mainland, the lease-in lease-out ("LILO") benefit arising from LILO agreements with several Interior municipalities.

The 2013 rate base, as reflected in the 2012-2013 RRA, is $2,810.5 million for FEI and $9,241 thousand for FEFN.[44] The net plant in service accounts for $2,645.3 million[45] or approximately 94 per cent of the total rate base in FEI and $9,193 thousand[46] or approximately 99% of the total rate base in FEFN. The details of each element of rate base were reviewed in the 2012-2013 RRA.

3.2.3 OPERATING DATA, RATES AND REVENUE TO COST RATIOS FOR FEI (MAINLAND)

3.2.3.1 FEI (Mainland) Operating Data

The table below summarizes operating data for FEI (Mainland) such as annual sales volumes, number of customers, average use rate, rate base and O&M expenses. The information presented is for the years 2006 to 2010, as well as the forecasts for 2011 to 2013. The data provides insight into the challenges FEI faces.

Table 3-2: FEI Operating Data[47]

FEI Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	209,077	209,077	210,091	200,822	201,111	205,987	206,716	207,160
Customers (Average)	802,743	816,427	825,696	832,751	839,017	846,522	852,937	859,708
Net Customer Additions		13,684	9,269	7,055	6,266	7,505	6,415	6,771
Normalized Average Use Rate*	97	96	93	93	93	92	91	90
Rate Base	$ 2,442,352	$ 2,426,180	$ 2,474,447	$ 2,462,143	$ 2,525,213	$ 2,542,002	$ 2,753,641	$ 2,810,535
Gross O&M Expenses (Nominal)	$ 179,206	$ 178,973	$ 185,739	$ 191,945	$ 206,519	$ 214,035	$ 230,189	$ 241,103
Unit Figures								
Rate Base Per Customer	$ 3,043	$ 2,972	$ 2,997	$ 2,957	$ 3,010	$ 3,003	$ 3,228	$ 3,269
O&M Per Customer	$ 223	$ 219	$ 225	$ 230	$ 246	$ 253	$ 270	$ 280

*Based on Residential Customers

The table shows that the residential normalized average use rate per customer has been steadily decreasing. The factors that have contributed to this decline are discussed in Section 4.1.

3.2.3.2 FEI (Mainland) Rate Schedules

FEI has a diverse range of customers with unique energy requirements. FEI assigns customers to rate classes based on each customer's consumption pattern and usage characteristics. Each customer is then billed for energy charges based on the rates applicable to that rate class. The

44 Appendix H-1, Tab 7.1, Schedule 41, Column 5, Line 31; Appendix H-4,Tab 7.4, Schedule 41, Column 5, Line 28
45 Appendix H-1, Tab 7.1, Schedule 41, Column 5, Line 21
46 Appendix H-4, Tab 7.4, Schedule 41, Column 5, Line 21
47 2006-2010 amounts as shown in Appendix D of 2012/2013 Revenue Requirement Application filed May 4, 2011; 2011-2013 amounts as shown in Appendix H-1

Inland and Columbia regions have the same rate classes as the Mainland region (other than Rate Schedules 22A and 22B).

FEI's various rate schedules can be placed into one of two groups. The first group consists of the rate schedules that do not require a written contract to be executed between FEI and the customer. These rate schedules are as follows:

- **Rate 1: Residential -** includes service to all residential applications in single-family residences, separately metered single family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
- **Rate 1B: Residential Biomethane Service -** serves customers with a normalized annual consumption at one premise of less than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- **Rate 1U: Residential Service -** serves customers using a licensed marketer, and having a normalized annual consumption at one premise of less than 2,000 Gigajoules. Customers must appoint a licensed marketer to enrol in this service.
- **Rate 2: Small Commercial Service -** serves customers with a normalized annual consumption at one premise of less than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- **Rate 2B: Small Commercial Biomethane Service -** serves customers with a normalized annual consumption at one premise of less than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- **Rate 2U: Small Commercial Service -** serves customers using a licensed marketer, and having a normalized annual consumption at one premise of less than 2,000 Gigajoules, for use in approved appliances in commercial, institutional or small industrial operations.
- **Rate 3: Large Commercial Service -** serves customers with a normalized annual consumption at one premise of greater than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- **Rate 3B: Large Commercial Biomethane Service -** serves customers with a normalized annual consumption at one premise of greater than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- **Rate 3U: Large Commercial Service -** serves customers using a licensed marketer and having a normalized annual consumption at one premise of greater than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

The second group of FEI rate schedules requires written contracts to be executed between FEI and the customer. These rate schedules are as follows:

- **Rate 4: Seasonal Service -** Seasonal Service is available to customers that consume natural gas mainly during the summer season (from April to October). During the summer months, their service is firm. If services are available during the other periods of the year, it would be on an interruptible basis.
- **Rate 5/25: General Firm Service -** General Firm Service rate schedules generally serve larger volume process load customers who use gas for more than space heating. Customers in these Rate Schedules generally have a higher load factor than residential and commercial customers due to their consumption patterns. Customers in these Rate Schedules pay a monthly demand charge, in addition to a monthly basic charge and variable delivery charge that recover some of the fixed demand related costs related to this customer group. This demand charge reflects the demand they place on the system infrastructure required to meet their peak demand. As such, the better the customer's individual load factor, the lower the demand charge per unit of consumption. Rate schedule 25 is the transportation option for Rate Schedule 5.
- **Rate 6: Natural Gas Vehicle Service -** NGV service is available to customers who retail natural gas to customers with natural gas vehicles, or fleet customers who use natural gas for their own fleet. Typical end-use applications include light, medium and heavy-duty vehicles. Rate Schedule 6 includes a monthly basic charge and a variable delivery, and gas cost recovery charge.
- **Rate 6A: General Service Vehicle Refuelling Service -** This rate schedule is available to customers who require on-site refuelling service through a compressor for transportation use.
- **Rate 6P: Public Service Natural Gas Vehicle Refuelling Service -** This rate schedule is applicable only to customers who use a dispenser provided by FEI for public use for on-site vehicle refuelling service through a compressor.
- **Rates 7 and 27: General Interruptible Service -** Rate schedules 7 and 27 provide customers that are able to have their service curtailed or interrupted during peak periods with non-firm service at discounted rates. Interruptible service is priced at a discount from firm service, where the discount reflects the amount deemed to be sufficient to encourage interruptible customers to remain interruptible while maximising the amount of revenue credited back to firm service customers. Customers in these rate schedules utilize the Company's firm service excess capacity during most of the year, thereby reducing the net cost of service that must be recovered in firm service rates. Typically, large volume process load customers with annual consumption ranging from 10,000 GJ to 150,000 GJ per year, such as manufacturers, greenhouses and service industries that can tolerate interruption in gas usage are served under these rate schedules. Rate Schedule 27 is the transportation option for Rate Schedule 7.

- **Rate 11B: Biomethane Large Volume Interruptible Sales -** This rate schedule applies to transportation customers who have entered into a Biomethane Large Volume Interruptible Sales Agreement, or if the customer is a shipper agent, all members of the group which the customer represents have entered into a transportation agreement under Rate Schedule 22, 22A, 22B, 23, 25, or 27.
- **Rate 14: Term and Spot Gas Sales -** This rate schedule applies to the sale of term and spot gas at the Point of Sale as defined in the sales agreement.
- **Rate 16: Interruptible Liquefied Natural Gas Sales and Dispensing Service -** This rate schedule applies to customers who request FEI to provide services for liquefaction of natural gas and dispensing of LNG at FEI's LNG plant at Tilbury.
- **Rate 22: Large Volume Interruptible Transportation -** Rate schedule 22 services FEI's largest interruptible customers. Under this rate schedule, customers are obligated to purchase a minimum of 12,000 GJ per month of delivery costs, regardless of whether or not that was consumed. Annual consumption in this rate schedule though can range from 150,000 GJ to 2,000,000 GJ per year. Like rate schedules 7 and 27, rate schedule 22 interruptible service is priced at a discount from firm service.
- **Rate 22A: Transportation Service (Closed) Inland Service Area -** Rate schedule 22A applies to Inland service area transportation customers for the provision of firm and interruptible transportation services through one meter station.
- **Rate 22B: Transportation Service (Closed) Columbia Service Area -** Rate schedule 22B applies to Columbia service area transportation customers for the provision of firm and interruptible transportation services through one meter station.
- **Rate 23: Large Commercial Transportation Service -** Large Commercial Transportation Service serves customers with a normalized annual consumption at one premise of greater than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations. Rate schedule 23 is the transportation option for Rate Schedule 3.
- **Rate 26: NGV Transportation Service –** Rate schedule 26 applies to natural gas vehicle transportation service for customers with consumption of greater than 2,000 GJ annually that will only use the gas to fuel vehicles.
- **Rate 30: Off System Sales and Purchases –** Rate schedule 30 applies to customers who enter into a contract for the short-term sale and purchase of natural gas.
- **Rate 36: Commodity Unbundling Service -** Rate schedule 36 establishes the terms and conditions upon which FEI may purchase, on a firm basis, a quantity of gas from a marketer that is approximately equal to the aggregated normalized forecast load requirements of customers enrolled in Commodity Unbundling Service under rate schedule 1U, 2U or 3U that have a gas supply contract with a marketer. In addition to the purchase of gas from the marketer by FEI, this rate schedule provides for the billing

by FEI of such customers for gas and other services provided by FEI to the customers' premises.

- **Rate 40: West to East SCP Transportation Service -** Rate schedule 40 applies to the provision of transportation service in a west to east direction through the FEI system made possible by utilizing the Southern Crossing Pipeline ("SCP").

3.2.3.3 2013 FEI (Mainland) Revenue to Cost Ratios

A Cost of Service Allocation study serves to determine whether the revenues collected from each rate class recover that class' contribution to the cost of service. One measure used to determine this factor is the revenue to cost ratio.

In order to provide a snapshot of the revenue to cost ratios for the rate classes in FEI (Mainland) for 2013, the revenue to cost ratios derived from the COSA model are summarized below.[48] Section 9.6.2 provides further discussion on the COSA allocation methodology.

Detailed COSA schedules are included in Appendix H-5.

Table 3-3: 2013 FEI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	92%
Rate 2 - Small Commercial	103%
Rate 6 - Seasonal	124%
Rate 3 & 23 - Combined	117%
Rate 5 & 25 - Combined	146%

3.2.4 OPERATING DATA, RATES AND REVENUE TO COST RATIOS FOR FORT NELSON

3.2.4.1 FEFN Operating Data

While being a relatively small region, Fort Nelson has enjoyed the operational efficiencies of a large utility simply by being a service area of FEI. However, Fort Nelson's small customer base leaves Fort Nelson vulnerable to rate swings from capital investments and loss of throughput.

The table below summarizes operating data for the FEFN region such as annual sales volumes, number of customers, average use rate, rate base and O&M expenses. The information presented is for the years, 2006 to 2010, as well as the forecasts for 2011 – 2013.

[48] Appendix H-5, Schedule 1, Line 23

Table 3-4: FEFN Operating Data[49]

FEFN Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	906	816	751	621	615	624	632	641
Customers (Average)	2,325	2,340	2,355	2,355	2,360	2,386	2,405	2,427
Net Customer Additions		15	15	-	5	26	19	22
Normalized Average Use Rate*	142	142	140	138	141	141	140	140
Rate Base	$ 4,825	$ 5,048	$ 5,093	$ 5,055	$ 5,410	$ 5,755	$ 7,392	$ 9,241
Gross O&M Expenses (Nominal)	$ 820	$ 835	$ 740	$ 784	$ 794	$ 812	$ 884	$ 911
Unit Figures								
Rate Base Per Customer	$ 2,075	$ 2,157	$ 2,163	$ 2,146	$ 2,292	$ 2,412	$ 3,073	$ 3,808
O&M Per Customer	$ 353	$ 357	$ 314	$ 333	$ 336	$ 340	$ 368	$ 375

*Based on Residential Customers

Operationally, Fort Nelson benefits from the cost structure of FEI. These benefits include more stable commodity costs, lower cost of capital, reduced cost of materials and supplies and more efficient operating and maintenance cost structures.

FEI is a large buyer of natural gas and due to its relationships with gas suppliers, FEI is able to contract for cost effective and reliable supply for Fort Nelson customers.

In addition to commodity-related benefits, Fort Nelson benefits from FEI's access to low cost capital funding. On its own, Fort Nelson would likely not be able to obtain access to funds at the favourable rates and terms that FEI is able to obtain as a larger utility. The purchasing power of a larger company also leads to reduced costs of pipe and other materials and supplies.

Another benefit afforded to Fort Nelson is access to the necessary resources, expertise and training in all areas affecting gas distribution utilities, such as the engineering department, human resources personnel, a comprehensive IT system, etc. Fort Nelson has historically enjoyed many of the benefits that typically only accrue to a large gas utility.

3.2.4.2 FEFN Rate Schedules

Fort Nelson has a less diverse customer base than FEI, and therefore fewer rate classes. Below is a summary of the current Fort Nelson rate schedules under which customers currently receive natural gas service:

- **Rate Schedule 1: Residential** - Rate schedule 1 includes service to all residential customers in single-family residences, separately metered single-family apartments and common areas serving strata lot owners of residential condominium complexes.
- **Rate Schedule 2.1: General Service Rate ("GSR")** - Rate schedule 2.1 applies to commercial customers with annual consumption of 6,000 GJ or less.
- **Rate Schedule 2.2: General Service Rate** - Rate schedule 2.2 applies to commercial customers with annual consumption of 6,000 GJ or more.

49 2006-2010 amounts as shown in Appendix D of FEU 2012/2013 Revenue Requirement Application filed May 4, 2011; 2011-2013 amounts as shown in Appendix H-4..

- **Rate Schedule 2.3: Natural Gas Vehicle Fuel Service** – Rate schedule 2.3 applies to customers who purchase gas as fuel to operate vehicles. Currently no customers are served under this rate schedule.
- **Rate Schedule 2.4: Compression/Dispensing Service** – Rate schedule 2.4 applies to customers who require on-site compression and refuelling services, at rates which are fully compensatory, and filed, as required with the Commission. Currently no customers are served under this rate schedule.
- **Rate Schedules 3.1, 3.2 and 3.3: Industrial Service** - Rate schedules 3.1, 3.2 and 3.3 serve large industrial customers. Rate Schedule 3.1 serves those with annual consumption of 96,000 GJ or less, while Rate Schedule 3.2 serves those with annual consumption of 96,000 GJ to 360,000 GJ and Rate Schedule 3.3 serves those with annual consumption equal to or greater than 360,000 GJ. Currently, no customers are served under these rate schedules.
- **Rate Schedule 25: General Firm Transportation** - Rate schedule 25 is the rate schedule 3.1/3.2/3.3 transportation service for industrial customers. Currently one customer with two accounts is served under this rate schedule.

3.2.4.3 2013 FEFN Revenue to Cost Ratios

A COSA study conducted for the Fort Nelson region using forecasted 2013 data produced revenue to cost ratios which are summarized below[50]. Detailed COSA schedules are included in Appendix H-8.

Table 3-5: 2013 FEFN COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	81%
Rate 2.1 - General Service 2.1	116%
Rate 2.2 - General Service 2.2	129%
Rate 25 - Firm Transportation Service	126%

3.3 FortisBC Energy (Vancouver Island) Inc.

FEVI is a separate utility, and has maintained its own separate rate base and rate structure after being acquired from Westcoast Energy Inc. in 2002.

Distribution of natural gas on Vancouver Island and the Sunshine Coast began in 1991, through the Vancouver Island Natural Gas Pipeline. Pacific Coast Energy Corporation ("PCEC") owned and operated the high pressure transmission pipeline and three Centra companies[51] operated

50 Appendix H-11, Schedule 1, Line 23

51 Centra Gas British Columbia Inc. (Inc. No. 0060334), Centra Gas Victoria Inc. (Inc. No. 0356486) and Centra Gas Vancouver Island Inc. (Inc. No. 0355320).

the distribution systems. On January 1, 1996, PCEC acquired, by way of an asset transfer agreement, the assets of the three Centra companies, and changed its name to Centra Gas British Columbia Inc. ("Centra Gas").

In March 2002, BC Gas Inc. purchased Centra Gas from Westcoast Energy Inc. In 2003, BC Gas Inc. changed its name and the names of each of its corporate entities, with the holding company becoming Terasen Inc. and Centra Gas becoming Terasen Gas (Vancouver Island) Inc.

In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc. and on March 1, 2011, the Terasen group of companies was renamed, with Terasen Gas (Vancouver Island) Inc. becoming FortisBC Energy (Vancouver Island) Inc.

In order to bring natural gas service to Vancouver Island residents, the Vancouver Island Gas Pipeline Project was initiated in February 1988. Construction began in 1989 and was completed in 1991. Both the pipeline and distribution facilities received initial financial assistance from the Federal and Provincial Governments, with the Vancouver Island Gas Joint Venture ("VIGJV") customers being eligible for conversion grants. Under the Consolidated Rate Stabilization Agreement between Centra Gas (the distribution utility at the time) and the Province, gas rates to distribution customers were decoupled from the cost of providing service and were set at a discount to oil and/or electricity. The Province provided a guarantee that absorbed the shortfall between revenues from customers and the costs of the transmission and distribution facilities.

By the mid-1990s a financial restructuring of the pipeline and distribution facilities was needed to achieve financial viability. The restructuring was finalized in late 1995, according to which the Consolidated Rate Stabilization Agreement was replaced by the VINGPA and the Vancouver Island Natural Gas Pipeline Act Special Direction[52] to the Commission (the "Special Direction").

As part of the restructuring, the Province made a $120 million lump sum payment as a contribution to capital costs with a corresponding reduction in Centra Gas' rate base as set out in the Special Direction. The Federal and Provincial Governments had previously provided $75 million to PCEC to assist in the construction of the pipeline from Vancouver Island to the Sunshine Coast. Under the Pacific Coast Energy Pipeline Agreement, FEVI's predecessor, as part of the restructuring, agreed to repay the Canada Repayable Contribution ($50 million) and the British Columbia Repayable Contribution ($25 million).

The VINGPA and Special Direction also contemplated the payment by the Provincial Government of gas royalty revenues ("Royalty Revenues") to FEVI through to 2011, which are based on the wellhead price of gas. These Royalty Revenues have mitigated fluctuations in the cost of gas to the benefit of FEVI's core market customers.

[52] OIC No. 1510 (Dec. 13, 1995) made pursuant to the Vancouver Island Natural Gas Pipeline Agreement Act, R.S.B.C. 1996, Chap. 474.

The payments of the Canada and British Columbia Repayable Contributions in addition to the cessation of Royalty Revenues are two of the drivers in bringing forward the Application at this time.

The regulation of FEVI has taken place within the parameters defined by the Special Direction since the 1995 restructuring. The Special Direction contemplates accumulated revenue shortfalls (referred to as the Accumulated Revenue Deficiency) being recorded in the Revenue Deficiency Deferral Account ("RDDA"). Within the parameters of the Special Direction, rates continued to be set below the cost of service and the balance in the RDDA increased to an $87.9 million deficit by 2002, and was forecast to be approximately $90.2 million by 2003.

Sections 2.8 and 2.10(j) of the Special Direction instructed that beginning January 1, 2003, rates were to be set at a level that would recover the cost of service and also include an amount sufficient to eliminate the RDDA balance in the "shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates." An ever-increasing deficiency was not, of course, sustainable.

The need to eliminate the balance in the RDDA was addressed in Centra Gas' 2002 Rate Design Application. The main objectives of the application were to set rates that would fully recover the overall cost of service, initiate amortization of the accumulated revenue deficiency and maintain the long-term financial sustainability of the entity. To achieve these objectives, a "soft-cap" rate mechanism was proposed to set rates relative to the cost of alternative energy sources, ensuring competitiveness with alternative energy providers. The margin above the cost of service was proposed to be used to pay down the RDDA balance. This methodology was endorsed by the Commission following an oral public hearing, and was determined to be the most reasonable and effective method of setting rates for Vancouver Island.

The RDDA balance was amortized sooner than had been anticipated, and was fully eliminated by the end of 2009. Recognizing that the Royalty Revenues would be discontinued at the end of 2011, the 2010-2011 FEVI Revenue Requirements and Rate Design Application recommended and the Commission approved that rates be frozen for 2010 and 2011 for core market customers. The surplus revenue that resulted from this rate freeze was captured in a deferral account called the RSDA. The RSDA was intended to accumulate revenue that would later be used to offset the loss of Royalty Revenues and mitigate the impact of forecasted rate increases of approximately twenty percent for residential customers.[53]

The FEU 2012-2013 RRA further proposed that Vancouver Island rates remain unchanged for 2012 and 2013. This rate freeze would ensure continued rate stability for Vancouver Island customers, and would allow sufficient time to implement an appropriate longer term solution to protect Vancouver Island customers against potential future rate increases. A continuity of the forecast balance in the RSDA from 2010 through 2013 is provided in the table below.

53 All else equal, the impact to delivery rates of the loss of the Royalty Revenues is the 2011 forecast royalty credits of $40.091 million that were included in the determination of the 2011 rates for FEVI (Commission Order No. G-140-09) divided by the 2012 revenue at existing rates of $194.132 million

Table 3-6: The RSDA Provides Short Term Rate Stability[54]

($ Thousands)	Actual 2010	F/S Actual 2011	Forecast 2012	Forecast 2013
Opening RSDA Balance, net of tax	(3,300)	(35,618)	(67,392)	(74,278)
Annual (Surplus)/ Deficiency	(44,743)	(41,533)	(6,389)	12,194
Add: Interest on Balance	(457)	(1,697)	(2,792)	(3,485)
Less: Tax	12,882	11,456	2,295	(2,177)
Closing RSDA Balance, net of tax	**(35,618)**	**(67,392)**	**(74,278)**	**(67,746)**
Tax Rate	28.5%	26.5%	25.0%	25.0%
Closing RSDA Balance, before tax	**(49,816)**	**(91,690)**	**(99,037)**	**(90,328)**

In 2011, the Mt. Hayes LNG Storage Facility was constructed and brought into service. This facility provides a reliable source of gas supply during peak demand periods, and also provides gas delivery to FEI. The implementation of this project has further integrated the FEI and FEVI systems.

At the present time, with the RDDA reduced to zero and the cessation of the Royalty Revenues, the Special Direction has essentially run its course. 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. As the RDDA has been reduced to zero and condition (b) expired on January 1, 2011, the remaining condition to be met to bring the Special Direction to an end is the termination of the Squamish Gas TSA. Upon amalgamation, the Squamish Gas TSA would terminate and the Special Direction would cease to have any application. With FEVI having accumulated a surplus in its RSDA, the present time is opportune for bringing an end to the Special Direction and implementing common rates with the FEU.

Today, FEVI provides natural gas transmission and distribution services to approximately 102,000[55] residential, commercial, and industrial customers in approximately 40 communities on Vancouver Island, the Sunshine Coast and Powell River. Service is provided through approximately 6,360 kilometres of pipelines.

3.3.1 FINANCIAL OVERVIEW OF FEVI

As with Mainland and Fort Nelson, the total cost of service for Vancouver Island can be summarized into two main components - the delivery cost of service (or delivery margin) and the cost of gas, each of which is discussed separately below. With respect to its rate structure, Vancouver Island is unique in that customers pay a single volumetric energy charge in addition

[54] The 2011 additions and balance are shown as projected. Material changes are not expected from the projection shown in this table and the actual balance as confirmed by the 2011 audited financial statements.

[55] FEU Gas Sales Statistics for BCUC 2011/12 Annual Report to the Legislature

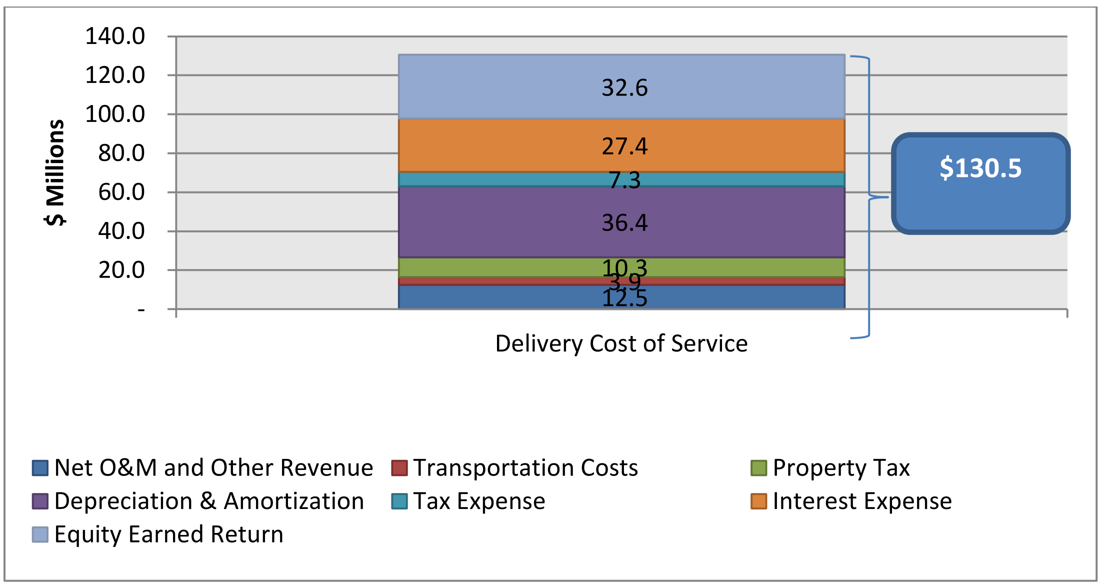
to their daily charge. That is, both the delivery costs and cost of gas are recovered through a single combined volumetric energy charge (as well as the fixed daily charge).

3.3.1.1 Delivery Cost of Service

The Vancouver Island delivery cost of service is comprised of operating and maintenance costs, transportation costs associated with the use of the Mainland transmission system and the capacity rights agreement with BC Hydro[56], property taxes, amortization expense associated with deferral accounts, depreciation expense associated with the recovery of capital investments, financing costs (both debt and equity) as well as income tax expense.[57] Other revenue is also included as an offset to costs.[58]

The delivery cost of service, as proposed in the 2012-2013 RRA, is $130.5 million.[59] The details of each element of the delivery cost of service were reviewed in the 2012-13 RRA and are summarized in Figure 3-6 below.

Figure 3-6: Vancouver Island 2013 Delivery Cost of Service ($ millions) [60]



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56 FEVI and BC Hydro have a Peaking Agreement 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. FEVI pays a capacity right payment to each month 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.

57 The FEVI removal cost provision is also included in delivery margin and for presentation purposes is combined with depreciation expense on Schedule 6, Column 5, Line 29 of Tab 7.2 in Appendix H-2

58 Other revenue includes revenue from service work (connection charges), late payment charges and returned cheques and LNG mitigation revenue from FEI and a transfer of FEVI LNG costs to commodity.

59 Appendix H-2, Tab 7.2, Schedule 6, Column 5, Line 24

60 Appendix H-2, Tab 7.2, Schedule 6, Column 5. For a breakdown of earned return (interest expense and equity return) please refer to Schedule 81, Column 7.

The figure above shows that the cost profile of Vancouver Island is such that depreciation and amortization, equity return and interest expense form the largest components of delivery margin, reflecting the relatively higher rate base and a newer system with greater costs.

The current capital structure and return on equity, as approved through BCUC Order No. G-158-09, is reflected in the stand-alone FEVI delivery cost of service.

3.3.1.2 Cost of Gas

Vancouver Island's cost of gas reflects the costs related to commodity including hedging, transportation, and storage resources.[61] The cost of gas for Vancouver Island also includes gas control management costs and company use gas costs.[62] This is different than Mainland where gas control management costs and the company use gas costs related to distribution line heater fuel, transmission compressor fuel, and Tilbury LNG plant fuel are captured in O&M expense. Further, Vancouver Island rates are not subject to quarterly resetting throughout the year for changes in the price of natural gas as is the case for FEI, FEW, and FEFN; however, variances between the actual incurred FEVI cost of gas and the Commission approved forecast cost of gas are captured in the Gas Cost Variance Account deferral ("GCVA") for refund or recovery to customers in future rates.[63]

The 2013 cost of gas, as reflected in the 2012-2013 RRA and for which FEVI sought approval, is $77.4 million and was based on the five-day average of the August 16, 17, 18, 19, and 22, 2011 forward prices, which reflected the forward prices utilized in the various FEU 2011 Third Quarter Gas Cost reports.[64] For purposes of updating the COSA studies, the forecast 2013 cost of gas has been updated to $76.5 million, based on the five-day average of the November 1, 2, 3, 4, and 7, 2011 forward prices, and which reflect the forward prices utilized in the FEVI 2011 Fourth Quarter Gas Cost report[65].

3.3.1.3 Rate Base

The rate base is comprised of mid-year net plant in-service (gross plant in service, less contributions in aid of construction, less accumulated depreciation relating to both, and negative salvage) and is 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; and the mid-year future income tax asset and offsetting liability.

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[61] Prior to January 1, 2012, as discussed in Section 3.3, the Vancouver Island cost of gas was offset by the Royalty Rebate arrangement with the Province (i.e. the Royalty Revenues).
[62] The portion of Vancouver Island company use gas pertaining to facilities is included in O&M expense and not cost of gas.
[63] BCUC Order No. G-2-03
[64] Appendix H-2, Tab 7.2, Schedule 13, Column 7, Line 19
[65] Appendix H-9, Schedule 1, Line 7

The Vancouver Island 2013 rate base, as reflected in the 2012-2013 RRA, is $815.7 million.[66] The net plant in service accounts for $797.1 million[67] or approximately 98 per cent of the total rate base in FEVI. The details of each element of rate base were reviewed in the 2012-13 RRA.

3.3.2 OPERATING DATA, RATE SCHEDULES AND REVENUE TO COST RATIOS FOR FEVI

3.3.2.1 *FEVI Operating Data 2006- 2013*

FEVI is a relatively new utility, and has the highest rate base per customer of all the regions. In addition, it has the lowest use per customer at approximately 50 GJs annually for residential customers. This is in contrast to Mainland and Fort Nelson residential customers, who use approximately 95 and 140 GJs respectively. The resulting low throughput negatively impacts customers as they are required to pay higher delivery rates to recover system costs.

To highlight the challenges faced by FEVI, the table below summarizes operating data for the FEVI region such as annual sales volumes, number of customers, average use rate, rate base and O&M expenses. The information presented is for the years 2006 to 2010, as well as the forecasts for 2011 – 2013.

Table 3-7: FEVI Operating Data[68]

FEVI Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	28,144	35,597	35,013	31,178	31,018	33,991	34,132	34,255
Customers (Average)	85,321	89,302	93,006	96,237	98,920	101,266	103,754	106,360
Net Customer Additions		3,982	3,704	3,231	2,683	2,346	2,488	2,606
Normalized Average Use Rate*	60	57	56	54	52	50	49	47
Rate Base	$ 464,180	$ 478,699	$ 511,422	$ 532,925	$ 547,661	$ 676,636	$ 788,314	$ 815,684
Gross O&M Expenses (Nominal)	$ 25,524	$ 24,514	$ 25,782	$ 26,514	$ 29,852	$ 32,617	$ 36,117	$ 36,232
Unit Figures								
Rate Base Per Customer	$ 5,440	$ 5,360	$ 5,499	$ 5,538	$ 5,536	$ 6,682	$ 7,598	$ 7,669
O&M Per Customer	$ 299	$ 275	$ 277	$ 276	$ 302	$ 322	$ 348	$ 341

*Based on Residential Customers

The table highlights the downward trend in the normalized average use rate for residential customers. At the same time, rate base per customer is forecast to continue increasing. From 2006 to 2013, it is estimated that the average use rate will fall from 60 GJs to 47 GJs or decrease 3 per cent on average each year, while rate base per customer will increase from $5,440 to $7,669, or an average of 6 per cent per year.

66 Appendix H-2, Tab 7.2, Schedule 41, Column 5, Line 30
67 Appendix H-2, Tab 7.2, Schedule 41, Column 5, Line 21
68 2006-2010 amounts as shown in Appendix D of 2012/2013 Revenue Requirement Application filed May 4, 2011; 2011-2013 amounts as shown in Appendix H-2.

3.3.2.2 FEVI Rate Schedules

FEVI customers are grouped into rate classes based on their individual energy requirements. The FEVI tariff is currently split into two parts: Distribution Sales Service and Transmission Transportation Service.

The following is a description of the Distribution Sales Service rate classes, as well as a description of each rate class's characteristics:

- **RGS: Residential General Service** – RGS includes service to single family residences, separately metered single family townhouses, row houses and apartments.
- **AGS: Apartment General Service** - AGS serves multi-residential dwellings with six or more residential units through one meter.
- **SCS-1 / SCS-2: Small Commercial Service** – SCS-1/SCS-2 serves small commercial customers with annual consumption of less than 600 GJ.
- **LCS-1 / LCS-2 / LCS-3: Large Commercial Service** – LCS-1, LCS-2 and LCS-3 serve larger commercial customers with consumption that exceeds 600 GJ annually. LCS 1 is for customers that annually consume between 600 GJ to 1,999 GJ, LCS 2 is for customers that annually consume 2,000 GJ to 5,999 GJ, while LCS 3 is for customers that annually consume 6,000 GJ and more.
- **LCS-13: Transportation Service** – LCS-13 is available to customers served off the distribution system with a minimum annual consumption of 6,000 GJ. To date no customers have elected service under this rate schedule.
- **LGS-25: Unauthorized Overrun Rate** - LGS-25 is available to customers serviced off the distribution system who require gas in excess of the Authorized Quantity to customers.
- **LGS-26: Authorized Overrun Rate** – LGS-26 is available to customers serviced off the distribution system who require gas in excess of their Contract Demand during the months of January, February, March, October, November and December.
- **HLF: High Load Factor** - The HLF rate structure serves commercial and industrial customers that utilize natural gas for process loads. Consumers must demonstrate a monthly coincidental peak (average January and February) load factor greater than 85 per cent.
- **ILF: Inverse Load Factor -** The ILF rate structure serves seasonal customers who consume most of their gas during summer (April through October); however they are allowed a maximum daily use for the winter months (November through March).

The following is a description of the Transmission Transportation Service for each of FEVI's independent contracts:

- **Vancouver Island Gas Joint Venture (VIGJV)** - This is a transportation service agreement which operates under an independent contract with periodically negotiated rates.
- **BC Hydro Island Cogen Plant** – This is a transportation service agreement which operates under an independent contract with periodically negotiated rates.

3.3.2.3 2013 FEVI Revenue to Cost Ratios

A COSA study conducted for FEVI using forecasted 2013 data produced the revenue to cost ratios summarized below[69]. Detailed COSA schedules are included in Appendix H-6.

Table 3-8: 2013 FEVI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
RGS - Residential	82%
AGS - Apartment General Service	115%
SCS1 - Small Commercial 1	112%
SCS2 - Small Commercial 2	152%
LCS1 - Large Commercial Service 1	124%
LCS2 - Large Commercial Service 2	121%
LCS3 - Large Commercial Service 3	117%
High Load Factor	140%
Inverse Load Factor	173%

3.4 FortisBC Energy (Whistler) Inc.

FEW operates as a separate public utility with a separate rate base and rate structure.

Until 2009, FEW was serviced by a piped propane distribution system. The propane gas distribution system in Whistler was established in 1980 and was originally owned and operated by the Resort Municipality of Whistler (the “RMOW”). In 1985 ICG Liquid Gas Ltd. (“ICG”) purchased the distribution system from the RMOW in a sale authorized by the Minister of Municipal Affairs. In addition, the Commission granted ICG an exemption from the Act until December 31, 1994. In 1987, ICG Utilities (British Columbia) Ltd. (“ICG Utilities”) purchased the distribution system, resulting in the exemption from regulation, pursuant to Section 103(3) of the Act being vacated.

In November 1990, ICG Utilities became Centra Gas. Centra Gas operated the Whistler system from 1990 to 1995. In 1996, Centra Gas was restructured and the Whistler-based assets of the company were transferred to a new company, Centra Gas Whistler Inc.

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[69] Appendix H-9, Schedule 1, Row 23

In March 2002, BC Gas Inc. purchased Centra Gas Whistler Inc. from Westcoast Energy Inc. In 2003, BC Gas Inc. changed its name and the names of each of its corporate entities, with the holding company becoming Terasen Inc. and Centra Gas Whistler Inc. changing its name to Terasen Gas (Whistler) Inc.

In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc. and on March 1, 2011, the Terasen group of companies was renamed, with Terasen Gas (Whistler) Inc. becoming FortisBC Energy (Whistler) Inc.

In April 2009, the construction of the natural gas pipeline lateral connecting the RMOW to the transmission system of FEVI was completed. From May to August of 2009, the piped propane system and customer appliances were converted to natural gas. The distribution system now consists of an underground distribution piping system, and a distribution piping Intermediate Pressure ("IP")/Distribution Pressure ("DP") station at Function Junction in Whistler. Natural gas is received at the IP/DP station from the intermediate pressure line of FEVI which interconnects with the FEVI transmission line at FEVI's Squamish station.

The conversion of the system from propane to natural gas has integrated the FEI and FEW operations, as both of these regions now utilize a shared portfolio to manage the cost of gas.

Today, FEW provides natural gas distribution services to approximately 2,600[70] residential and commercial customers in Whistler. Service is provided through approximately 139 kilometres of pipeline.

3.4.1 FINANCIAL OVERVIEW OF FEW

The total cost of service for Whistler can be summarized into two main components - the delivery cost of service (or delivery margin) and the cost of gas, each of which is discussed separately below.

3.4.1.1 Delivery Cost of Service

Delivery cost of service is comprised of operating and maintenance costs, transportation costs associated with the use of the Vancouver Island transmission system, property taxes, amortization expense associated with deferral accounts, depreciation expense associated with the recovery of capital investments, financing costs (both debt and equity) as well as income tax expense.[71] Other revenue is also included as an offset to costs.[72] The Whistler delivery cost is recovered through a fixed daily basic charge and a volumetric delivery rate.

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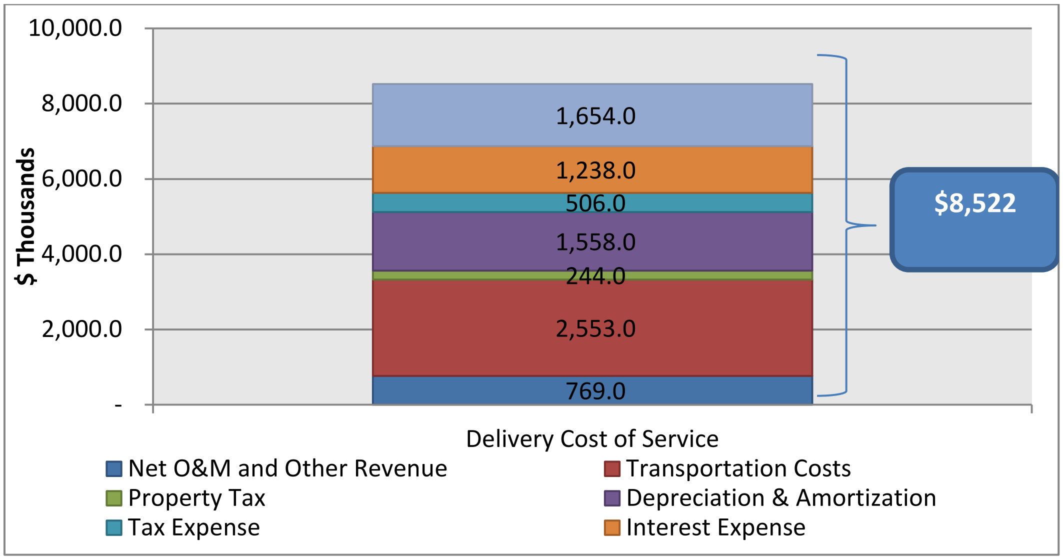
70 FEU Gas Sales Statistics for BCUC 2011/12 Annual Report to the Legislature

71 The FEW removal cost provision is also included in delivery margin and for presentation purposes is combined with depreciation expense on Schedule 6, Column 5, Line 23 of Tab 7.3 in Appendix H-3

72 Other revenue includes revenue from service work (connection charges), late payment charges and returned cheques

The FEW delivery cost of service to be recovered through 2013 stand-alone delivery rates, as proposed in the 2012-2013 RRA, is $8,522 thousand.[73] The details of each element of the delivery cost of service were reviewed in the 2012-13 RRA and are summarized in Figure 3-8 below.

Figure 3-7: Whistler 2013 Delivery Cost of Service ($ thousands)[74]



As evident from Figure 3-7 the cost profile in Whistler is different than Mainland and Fort Nelson because of recent major additions in 2009 to the Whistler deferral accounts and transportation costs pertaining to the Whistler Pipeline and conversion costs. In Mainland and Fort Nelson, the largest components of the delivery cost of service are operating and maintenance expense, depreciation and amortization and interest expense.

The current capital structure and return on equity, as approved through BCUC Order No. G-158-09, is reflected in the stand-alone FEW delivery cost of service.

3.4.1.2 Cost of Gas

As noted above, a single portfolio is used to manage the cost of gas for Mainland and Whistler, resulting in the same unit gas cost recovery charges applicable to sales customers in FEI and FEW.[75] The gas costs for Whistler customers are reviewed and approved by the Commission through separate applications. As a result, although required for purposes of determining the

[73] Appendix H-3, Tab 7.3, Schedule 6, Column 5, Line 18
[74] Appendix H-3, Tab 7.3, Schedule 6, Column 5. For a breakdown of earned return (interest expense and equity return) please refer to Schedule 81, Column 7.
[75] Midstream Cost Recovery Charges vary amongst the FEI service areas and Sales rate classes. The Lower Mainland Rate Schedule 3 Midstream Cost Recovery Charge is applicable to FEW sales customers, and in conjunction with the Commodity Cost Recovery Charge forms the total FEW Gas Cost Recovery Charge. Please note that FEW Commodity Cost Recovery Charge also includes Lower Mainland Rate Schedule MCRA Rider.

working capital component of rate base, the forecast cost of gas itself does not impact the determination of the cost of service or the resulting revenue surplus or deficiency in the RRA.[76]

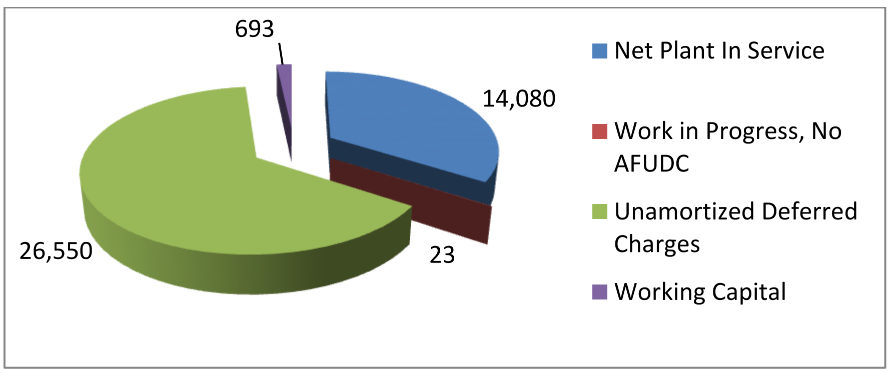
The 2013 cost of gas, as reflected in the 2012-2013 RRA, is $3,455 thousand in FEW and was based on the Commission approved gas cost recovery rates effective January 1, 2011.[77] For purposes of updating the COSA studies that are included in this Application, the forecast 2013 cost of gas and corresponding offsetting revenues have been updated to $3,777 thousand in FEW, based on the five-day average of the November 1, 2, 3, 4, and 7, 2011 forward prices, and which reflect the forward prices utilized in FEW's 2011 Fourth Quarter Gas Cost report[78].

3.4.1.3 Rate Base

The rate base is comprised of mid-year net plant in-service (gross plant in service, less contributions in aid of construction, less accumulated depreciation relating to both, and negative salvage) and is 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; and the mid-year future income tax asset and offsetting liability.

The 2013 Whistler rate base, as reflected in the 2012-13 RRA, is $41,346 thousand.[79] The details of each element of rate base were reviewed in the 2012-13 RRA and are summarized in Figure 3-8 below.

Figure 3-8: Whistler 2013 Rate Base ($ thousands) [80]



The unamortized deferred charges are proportionally larger in Whistler than in the other FEU because the costs associated with the Whistler Pipeline and the conversion from a propane to

[76] The revenue forecast used in the RRA includes commodity and midstream revenues which equally offset the forecast cost of gas, resulting in a net impact of zero to the revenue deficiency or surplus

[77] Appendix H-3, Tab 7.3, Schedule 13, Column 10, Line 13, those cost of gas rates remained in place for FEW through June 30, 2011

[78] Appendix H-10, Schedule 1, Lines 4 and 9

[79] Appendix H-3, Tab 7.3, Schedule 41, Column 5, Line 30

[80] Appendix H-3, Tab 7.3, Schedule 41, Column 5

natural gas distribution system have been captured in deferral accounts. The 2013 mid-year balance of the conversion costs deferral account is $12,178 thousand and the mid-year balance of the pipeline capital contribution deferral account is $13,435 thousand, with amortization periods of twenty and fifty years, respectively. [81]

3.4.2 OPERATING DATA, RATE SCHEDULES AND REVENUE TO COST RATIOS FOR FEW

3.4.2.1 FEW Operating Data 2006 - 2013

Being a relatively new utility, FEW faces the risks that many new utilities face: high unit and rate base costs per customer and a dependence on its large customers for sufficient throughput.

To highlight the challenges faced by FEW, the table below summarizes operating data for FEW such as annual sales volumes, number of customers, average use rate, rate base and O&M expenses. The information presented is for the years 2006 to 2010, as well as the forecasts for 2011 – 2013.

Table 3-91: FEW Operating Data[82]

FEW Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	734	742	709	629	765	731	716	709
Customers (Average)	2,368	2,391	2,434	2,519	2,586	2,592	2,610	2,629
Net Customer Additions		23	44	85	68	6	18	19
Normalized Average Use Rate*	86	96	95	83	99	102	104	106
Rate Base	$ 17,040	$ 16,830	$ 16,782	$ 31,518	$ 45,400	$ 44,892	$ 42,046	$ 41,346
Gross O&M Expenses (Nominal)	$ 821	$ 793	$ 906	$ 791	$ 773	$ 868	$ 904	$ 913
Unit Figures								
Rate Base Per Customer	$ 7,197	$ 7,040	$ 6,895	$ 12,515	$ 17,556	$ 17,322	$ 16,112	$ 15,729
O&M Per Customer	$ 347	$ 332	$ 372	$ 314	$ 299	$ 335	$ 346	$ 347

*Based on Residential Customers

Table 3-9 highlights a concerning trend in FEW, the forecast decrease in sales volumes. Although residential and small commercial customer additions and average use rate for residential and small commercial customers are forecast to increase slightly in 2012 and 2013, this increase is not enough to offset the decreasing average use rate for large commercial customers. Large commercial customers' average use rate has decreased since 2006; from a total use rate of 17.4 TJs for all large commercial customers to a forecast use rate of 9.2 TJs in 2013.

At the same time that sales volumes have decreased for the large commercial customers, rate base has increased, reaching a high of $17,556 rate base per customer in 2010. The increase in rate base is due to the Whistler Pipeline Conversion Project, and is forecast to decrease

81 Appendix H-3, Tab 7.3, Schedule 71, Column 11, Lines 9 and 10; for financial schedule presentation purposes the four individual pipeline and conversion cost accounts are summarized into one account.

82 2006-2010 amounts as shown in Appendix D of 2012/2013 Revenue Requirement Application filed May 4, 2011; 2011-2013 amounts as shown in Appendix H-3.

beginning in 2010, as the deferral accounts relating to the pipeline conversion costs are amortized.

In addition, FEW is dependent on the tourism industry, and a cyclical pattern of gas usage. This leaves FEW susceptible to swings in the economy. An economic downturn may have a disproportionate impact on FEW customers, as the small, seasonal customer base does not provide the same level of stability as seen in FEI.

3.4.2.2 FEW Rate Schedules

FEW utilizes only one rate schedule: the General Service Rate Schedule (SGS). This rate schedule serves all FEW customers from single family residences to large commercial customers such as large hotels. Within the General Service Rate Schedule, FEW has maintained additional customer segmentation for internal purposes based upon whether the end-use customer is a residential or commercial customer. Commercial customers have also been segmented by annual consumption thresholds to assist FEW with managing the business. A summary of the different internal customer segmentations that have been maintained under the General Service Rate (SGS) for FEW are as follows:

- **SGS 1/2: Small General Service (Residential)** – This segmentation is for residential customers.
- **SGS 1/2: Small General Service (Commercial)** – This customer segmentation is for smaller commercial customers who consume up to 600 GJ annually.
- **LGS 1 / LGS 2 / LGS 3: Large General Service** – This customer segmentation is for larger commercial customers. LGS 1 is for those customers that annually consume between 600 GJ to 1,999 GJ. LGS 2 is customers that annually consume 2,000 GJ to 5,999 GJ. LGS 3 is for those customers that annually consume 6,000 GJ and more.

3.4.2.3 2013 FEW Revenue to Cost Ratios

A COSA study conducted for FEW using forecasted 2013 data produced the revenue to cost ratios summarized below[83]. Detailed COSA schedules are included in Appendix H-10.

Table 3-10: 2013 FEW COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Residential	76%
Commercial	114%
LGS1 - Large Commercial Service 1	115%
LGS2 - Large Commercial Service 2	150%
LGS3 - Large Commercial Service 3	114%

83 Appendix H-10, Schedule 1, Row 23

3.5 The Utility Strategy Project – Functional Integration of the FEU

Although the FEU operate with four separate rate bases and have different rate structures that trace back to growth through acquisition, operationally the companies are integrated today.

Shortly after the acquisition of FEVI in 2002, FEI indicated that a number of synergies could be achieved through a common management and operating structure. To realize these efficiencies, FEI and FEVI embarked on a major restructuring initiative aimed at delivering substantial cost savings through a common management and operating structure. The integration initiative, known as the Utilities Strategies Project ("USP") essentially realized the majority of the savings that would normally be associated with legal amalgamation.

The USP initiative commenced September 10, 2003 with the planning and organizational tasks completed on December 12, 2003. Although the USP encompassed all of the FEU's service areas, the focus was primarily on the FEI and FEVI regions. The implementation of the USP incurred a total cost of approximately $15 million for one-time restructuring charges. The majority of the $15 million cost was related to severance pay-outs to the 115 employees who were made redundant, with the balance related to organizational restructuring changes. Since 2004, the USP has captured the savings that are available as a result of utilizing a shared management structure, and has continued to provide benefits to both customers and the shareholder.

This initiative has successfully harnessed the majority of amalgamation-related savings that are available to the Companies, leaving little opportunity for further savings to be realized. Any incremental savings that will be realized as part of the 2013 amalgamation are discussed in Section 6.6.4.

3.6 Summary

Through a series of acquisitions and amalgamations, the FEU has developed into one of the largest energy providers in British Columbia. This growth has resulted in FEU's current structure comprising four utility rate bases, each with its own unique rate structure and financial requirements.

To provide context for the amalgamation application, this section outlined the historical evolution of FEI, described the cost structure of each entity and also summarized key operational data.

4 OPERATING CONTEXT AND ISSUES ADDRESSED BY THIS APPLICATION

In this section the FEU define some of the key aspects of the context in which they operate, including government policy and changing customer preferences, and define the issues that are being addressed by this Application.

The section is organized as follows:

- Section 4.1 discusses the trend of declining total demand experienced by the FEU, including changes in government policy and the customer preferences that contribute to this trend.
- Section 4.2 discusses the first issue that this Application seeks to address – the existing rate disparity between FEU's service areas, and how this disparity will increase with a continuation of the trends discussed in Section 4.1.
- Section 4.3 discusses the second issue that this Application seeks to address - the upward pressure on FEVI rates as a result of the loss of government subsidies.
- Section 4.4 discusses the third issue that this Application seeks to address - the risk of long term rate instability for FEVI, FEW and FEFN from required localized capital investment and customer and volume loss.
- Section 4.5 is a summary of the three issues.

4.1 Decline in Total Demand

FEU's revenues are a result of total demand volumes, which are determined by the number of customers (and ability to add customers) and average use rates per customer. Over the past few years, the rate of customer growth has declined from the highs of the mid-2000s and overall, average use per customer for residential and commercial customers ("UPC") has decreased.

All else equal, the impact of these trends in customer additions and UPC is a reduction in total demand and upward pressure on rates. Given the factors driving these trends, including building and appliance regulations, government policies and consumer driven activities, it is likely that they will continue.

A brief explanation of the trend in total demand volume and related trends in customer growth and use per customer for each of the four utilities is set out below.

4.1.1 TOTAL ENERGY DEMAND 2003 – 2013

Overall energy demand is a function of both the number of customers (influenced by customer additions) and average use per customer. As the majority of the revenue collected by the FEU from customers is based on variable rates, total energy demand will have a direct impact on rates. A decline in total demand, all else equal, will cause upward pressure on rates.

While the overall energy demand for the FEU has declined by 6.7 percent from 2003 through 2011, much of this decline is from industrial customers. For residential and commercial customers, the overall energy demand has remained relatively flat over the same period, as the customer additions have, for the most part, offset the decline in average use per customer rates.

The following table summarizes the historical demand for each of the four utilities, by customer type, from 2003 through 2010, as well as the projection for 2011 through 2013.

Table 4-1: Normalized Annual Demand (PJs)84

FEI (Mainland):

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	72.5	71.9	69.2	69.9	70.6	68.8	69.9	70.0	69.9	69.8	69.8
Commercial[2]	45.2	45.1	43.7	44.0	45.4	45.7	47.1	46.5	46.6	46.9	47.2
Subtotal	**117.7**	**117.0**	**113.0**	**113.9**	**115.9**	**114.5**	**117.0**	**116.5**	**116.6**	**116.7**	**116.9**
Industrial[3]	66.2	63.6	63.3	58.3	60.0	55.3	48.4	51.5	51.2	51.5	51.6
Total	**183.9**	**180.6**	**176.2**	**172.2**	**176.0**	**169.8**	**165.4**	**168.0**	**167.8**	**168.3**	**168.5**

Vancouver Island:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[4]	4.0	4.0	4.2	4.6	4.6	4.7	4.6	4.7	4.6	4.6	4.5
Commercial[5]	7.3	7.2	7.4	7.3	7.5	7.3	7.2	7.1	7.1	7.2	7.3
Subtotal	**11.3**	**11.2**	**11.7**	**11.9**	**12.1**	**12.0**	**11.8**	**11.8**	**11.7**	**11.8**	**11.9**
Transportation[6]	21.2	21.5	22.1	16.3	23.3	22.3	18.9	19.5	22.3	22.3	22.3
Total	**32.5**	**32.8**	**33.8**	**28.3**	**35.4**	**34.4**	**30.7**	**31.3**	**34.0**	**34.1**	**34.2**

Whistler:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[7]	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commercial[8]	0.5	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.6**	**0.8**	**0.7**	**0.7**	**0.7**

Fort Nelson:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial[9]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**

TOTAL FEU:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential	77.0	76.4	73.9	75.0	75.6	74.0	75.1	75.2	75.1	74.9	74.8
Commercial	53.3	53.1	52.0	52.2	53.7	53.9	55.0	54.4	54.5	54.9	55.3
Subtotal	**130.2**	**129.5**	**125.9**	**127.1**	**129.4**	**127.9**	**130.0**	**129.6**	**129.6**	**129.8**	**130.1**
Industrial	66.2	63.6	63.3	58.3	60.0	55.3	48.4	51.5	51.2	51.5	51.6
Transportation	21.2	21.5	22.1	16.3	23.3	22.3	18.9	19.5	22.3	22.3	22.3
Total	**217.6**	**214.6**	**211.3**	**201.8**	**212.7**	**205.5**	**197.3**	**200.7**	**203.1**	**203.7**	**204.0**

Notes:
1. Rate 1
2. Rates 2, 3, and 23
3. Rates 4, 5, 6, 7, 22, 25, and 27
4. RGS
5. AGS, SCS1, SCS2, LCS1, LCS2, LCS3, HLF, ILF
6. BC Hydro & VIGJV
7. SGS Res
8. SGS Com, LGS1, LGS2, LGS3
9. Rates 2.1, 2.2

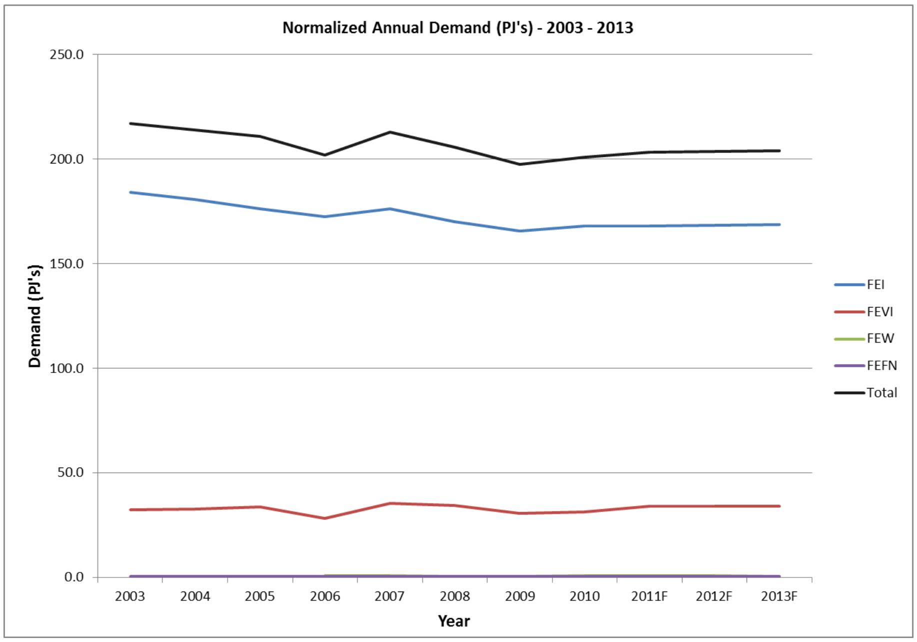
84 Normalized Demand Volumes are exclusive of FEVI Wheeling and Burrard Thermal volumes.

The demand volumes of the FEU are forecast to increase by only 0.9 PJs from 2011 to 2013, resulting in total demand volumes of 204.0 PJs for the FEU in 2013.

Although demand volume is forecast to increase slightly over the next two years, there has been a dramatic decrease compared to 2003, when total demand volumes were 217.6 PJs. This translates to a forecasted decrease of approximately 6.3 per cent from 2003 to 2013.

The figure below illustrates the gradual decrease in demand volumes for the FEU as a whole.

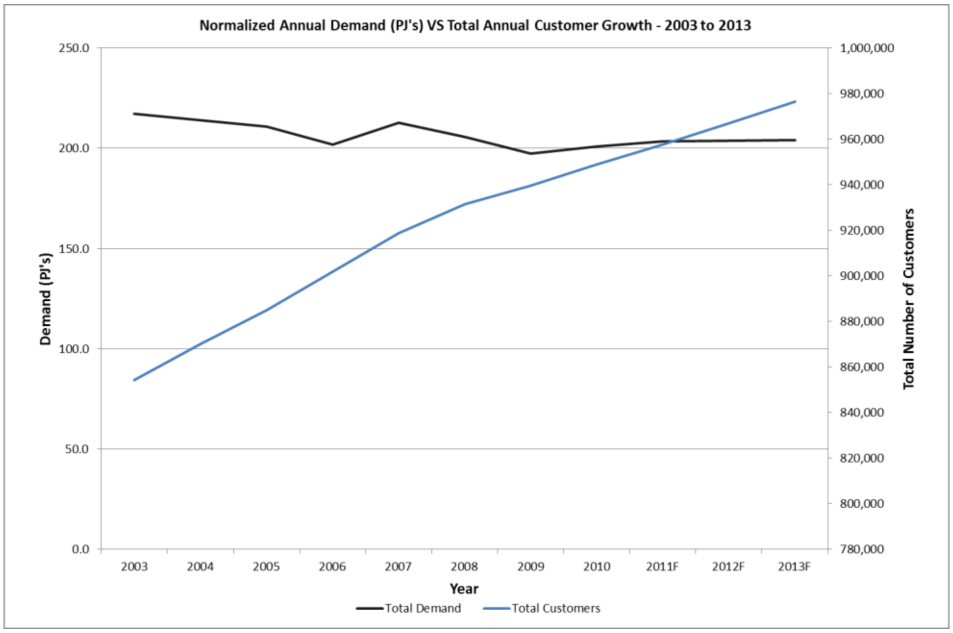
Figure 4-1: Total Demand Continues to Decline



The figure shows that the FEW and FEFN regions, although stable in terms of demand volumes, have little influence on overall demand volumes, as their customer base is relatively small and unable to impact total demand in a significant way. FEVI demand volumes are stable over this period, while FEI demand volumes continue to decline over the 2003 to 2013 period, driven in large part by the loss of industrial customers.

Customer additions from 2003 to 2011 have not been able to outpace the decrease in total demand volumes. The figure below illustrates the customers for the FEU, compared to the total demand volumes over the same period.

Figure 4-2: Total Demand Volumes vs. FEU Number of Customers 2003 - 2013



Customer additions have not translated to a significant increase in demand volumes for residential and commercial customers, as the effects of declining average use rates have had a large impact on total demand volumes.

The trends in customer additions and average use per customer are discussed below.

4.1.2 CUSTOMER ADDITIONS 2003 – 2013

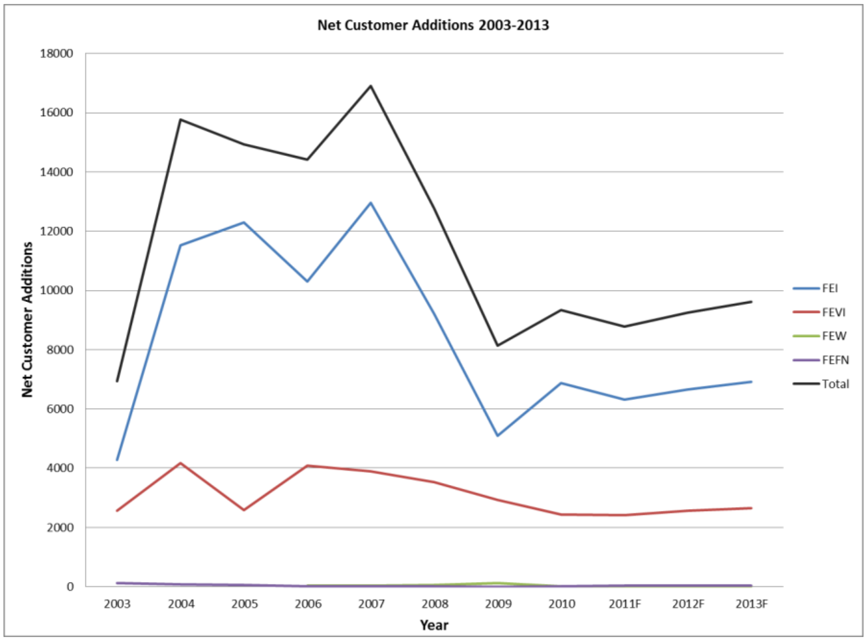
Customer additions are one of two key drivers in the demand for natural gas (with average use per customer being the other key driver). From 2003 to 2011, FEI, FEVI, FEW and FEFN as a whole connected 100,988 new net customers to its systems and had an average growth rate of 1.5 per cent per year. Residential customer additions account for the bulk of all customer additions.

Customer additions are highly correlated to the housing market, influenced both by the number of household formations and also the housing mix. Moreover, they are also a primary driver for capital expenditures. The decline in the growth rate of customers is attributed to the changing trend in housing mix away from single family dwellings to multi-family dwellings. Developers are partial to electric baseboards over natural gas due to the lower upfront capital costs. This has had an impact on the operations of the Companies.

The rate of growth in the customer base seen a decline since the mid-2000s for each of the four utilities. The 2009 global financial crisis resulted in sharp declines that year, with the exception of FEW. In 2009 FEW saw a large increase in customer additions due to the completion of the Whistler Pipeline Conversion Project. A large number of customers were converted to the natural gas system upon completion, accounting for the spike in customer additions that year.

The following figure illustrates the historical net customer additions over the period 2003 through 2010, as well as the forecast for net customer additions in 2011 and 2013.

Figure 4-3: Historical Net Customer Additions Have Experienced Declines in Past Decade



FEI experienced a high in 2007 of roughly 12,938 net customer additions, but it has declined since then. The projection for 2011 is for approximately 6,314 customer additions, slightly less than half of the 2007 high. FEVI and FEFN experienced peak customer additions in 2004 and 2003 respectively, but all areas have experienced declines from those highs. Whistler achieved a record high 123 customer additions in 2009, but has experienced a similar decline in customer attachments since then. All areas are forecast to experience modest growth in customer additions for 2012 and 2013.

The following table illustrates the historical customer additions by rate class for each of the four utilities for the period 2003 to 2010, as well as the forecast number of customer additions for 2011 and 2013. The table also provides the total number of customers for each utility.

Table 4-2: Net Customer Additions Have Been Declining since Mid-2000s

FEI (Mainland)	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	6,318	10,672	11,412	9,583	11,974	7,943	4,822	6,824	6,165	6,507	6,774
Commercial[2]	-2,035	746	967	655	1,090	1,283	298	143	149	149	149
Subtotal Net Additions	**4,283**	**11,418**	**12,379**	**10,238**	**13,064**	**9,226**	**5,120**	**6,967**	**6,314**	**6,656**	**6,923**
Industrial[3]	2	48	-91	38	-126	-54	-31	-96	0	0	0
Total Net Additions	**4,285**	**11,466**	**12,288**	**10,276**	**12,938**	**9,172**	**5,089**	**6,871**	**6,314**	**6,656**	**6,923**
Year-End Customers	774,174	785,640	797,928	808,204	821,142	830,314	835,403	842,274	848,588	855,244	862,167

FEVI	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[4]	2,556	3,951	2,723	3,798	3,757	3,326	2,785	2,350	2,328	2,463	2,564
Commercial[5]	6	212	-139	283	124	203	148	82	94	94	94
Total Net Additions	**2,562**	**4,163**	**2,584**	**4,081**	**3,881**	**3,529**	**2,933**	**2,432**	**2,422**	**2,557**	**2,658**
Year-End Customers	76,533	80,696	83,280	87,361	91,242	94,771	97,704	100,136	102,558	105,115	107,773

FEW	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[6]	93	56	30	43	34	36	116	12	14	14	15
Commercial[7]	3	-2	-3	-3	7	10	7	0	4	5	4
Total Net Additions	**96**	**54**	**27**	**40**	**41**	**46**	**123**	**12**	**18**	**19**	**19**
Year-End Customers	2,261	2,331	2,365	2,370	2,411	2,457	2,580	2,592	2,610	2,629	2,648

FEFN	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	100	52	26	3	7	-3	0	12	12	11	13
Commercial[8]	8	33	19	10	7	4	-2	9	11	11	11
Total Net Additions	**108**	**85**	**45**	**13**	**14**	**1**	**-2**	**21**	**23**	**22**	**24**
Year-End Customers	2,211	2,296	2,341	2,354	2,368	2,369	2,367	2,388	2,411	2,433	2,457

TOTAL FEU											
Residential	9,067	14,731	14,191	13,427	15,772	11,302	7,723	9,198	8,519	8,995	9,366
Commercial	-2,018	989	844	945	1,228	1,500	451	234	258	259	258
Subtotal Net Additions	**7,049**	**15,720**	**15,035**	**14,372**	**17,000**	**12,802**	**8,174**	**9,432**	**8,777**	**9,254**	**9,624**
Industrial	2	48	-91	38	-126	-54	-31	-96	0	0	0
Total Net Additions	**7,051**	**15,768**	**14,944**	**14,410**	**16,874**	**12,748**	**8,143**	**9,336**	**8,777**	**9,254**	**9,624**
Year-End Customers	855,179	870,963	885,914	900,289	917,163	929,911	938,054	947,390	956,167	965,421	975,045

Notes:
1. Rate 1
2. Rates 2, 3, and 23
3. Rates 4, 5, 6, 7, 22, 25, and 27
4. RGS
5. AGS, SCS1, SCS2, LCS1, LCS2, LCS3, HLF, ILF
6. SGS Res
7. SGS Com, LGS1, LGS2, LGS3
8. Rates 2.1, 2.2

The table indicates that although the number of residential customers is increasing for all entities, they are increasing at a slower pace in recent years. Small Commercial customer additions are forecast to remain stable, while Industrial customers are leaving the system. These trends are expected to continue.

4.1.3 AVERAGE USE PER CUSTOMER 2003 – 2013 FOR RESIDENTIAL AND COMMERCIAL CUSTOMERS

Average use per customer is the other key driver in the demand for natural gas. Overall, average use per customer has declined over the period 2003 through 2011, with a resulting impact on demand volumes. This can largely be attributed to changes to building and appliance codes, and provincial and municipal government policies on GHG reduction that are shaping customer behaviors regarding energy use and are aimed at reducing fossil fuel use within homes and business. The availability of demand-side management programs for consumers also factors into the decreasing UPC rates. This decline in use rates is forecast to continue.

The following section describes the average use rate per customer for each of the four utilities - FEI, FEVI, FEW and FEFN, starting with residential customers, then small commercial customers, and finally large commercial customers. The average use per customer rates have been normalized for weather, eliminating seasonal effects, which allows for a fair and consistent method of comparing average use rates over time.

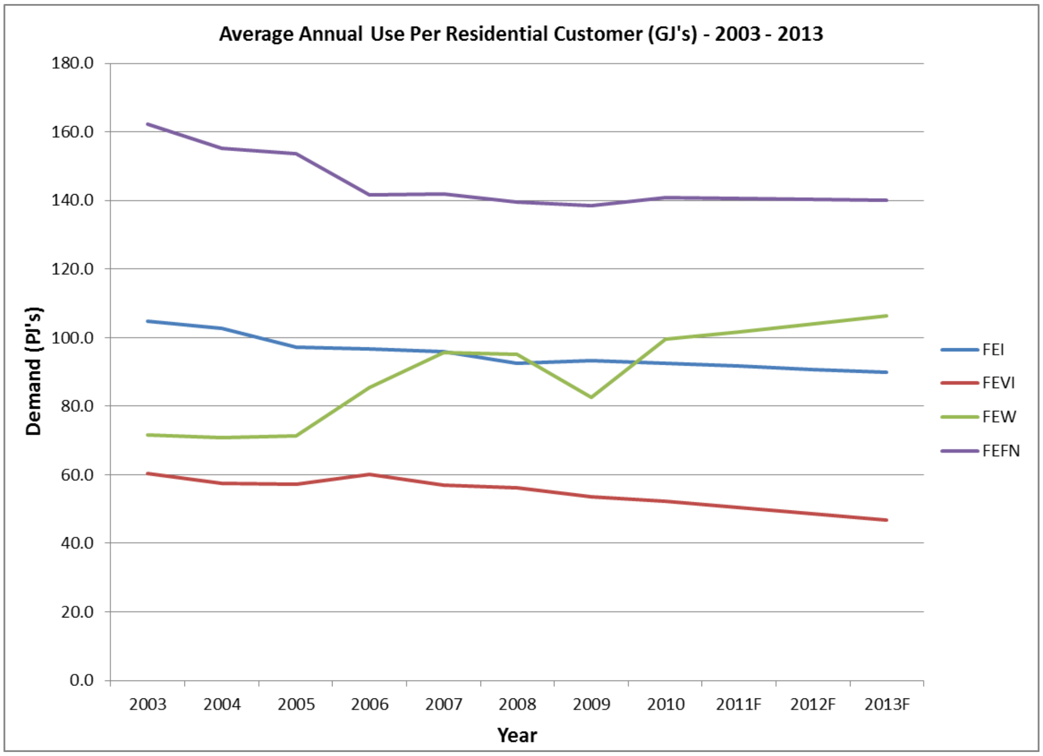
Residential Customers

Residential customers account for the bulk of demand volumes for the FEU. Residential customers, with the exception of Whistler residents, have seen a gradual decline in use rates.

Whistler residents, whose system was converted in 2009 from a piped propane system to natural gas, are experiencing higher use rates along with a shift towards natural gas appliances. As Table 4-2 above shows, FEW customer additions have slowed significantly since 2009.

Figure 4-4 below presents the normalized average annual use rates for residential customers of each of the four utilities for the period 2003 through to 2010, as well as the forecast average use per customer for 2011 and 2013.

Figure 4-4: Overall Normalized Actual Average Residential UPC (GJ/yr) Declining

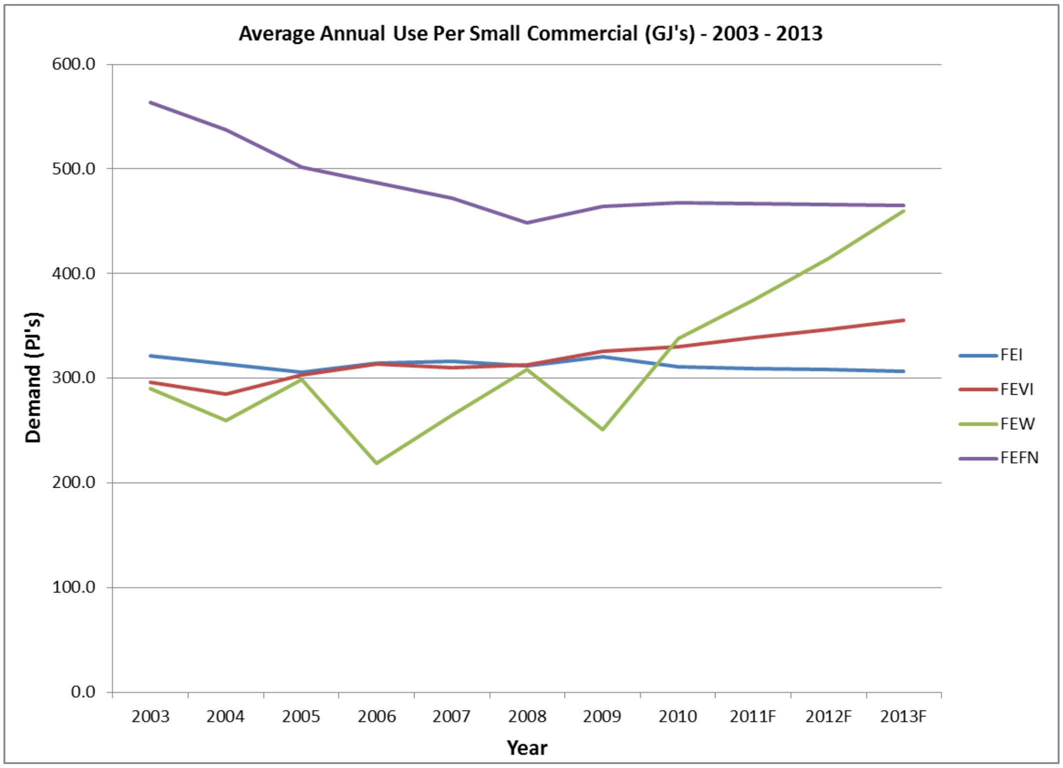


Average use per customer is influenced by a number of factors, including the retrofit of higher efficiency appliances, the shift towards more multi-family dwellings in the housing mix, demand side management programs, the carbon tax and government policy. All of these factors have collectively led to the decline in the average use per customer rate. These factors are expected to continue into the future. Together with the focus on energy efficiency, these factors have led to the decline in annual average use rates per customer, and a related impact on overall demand volumes.

Small Commercial Customers

The figure below presents the historical normalized average use rates, as well as the forecast for 2012 and 2013 for the Small Commercial customer rate class in each of the four regions.

Figure 4-5: Overall Normalized Actual Average Small Commercial UPC (GJ/yr)



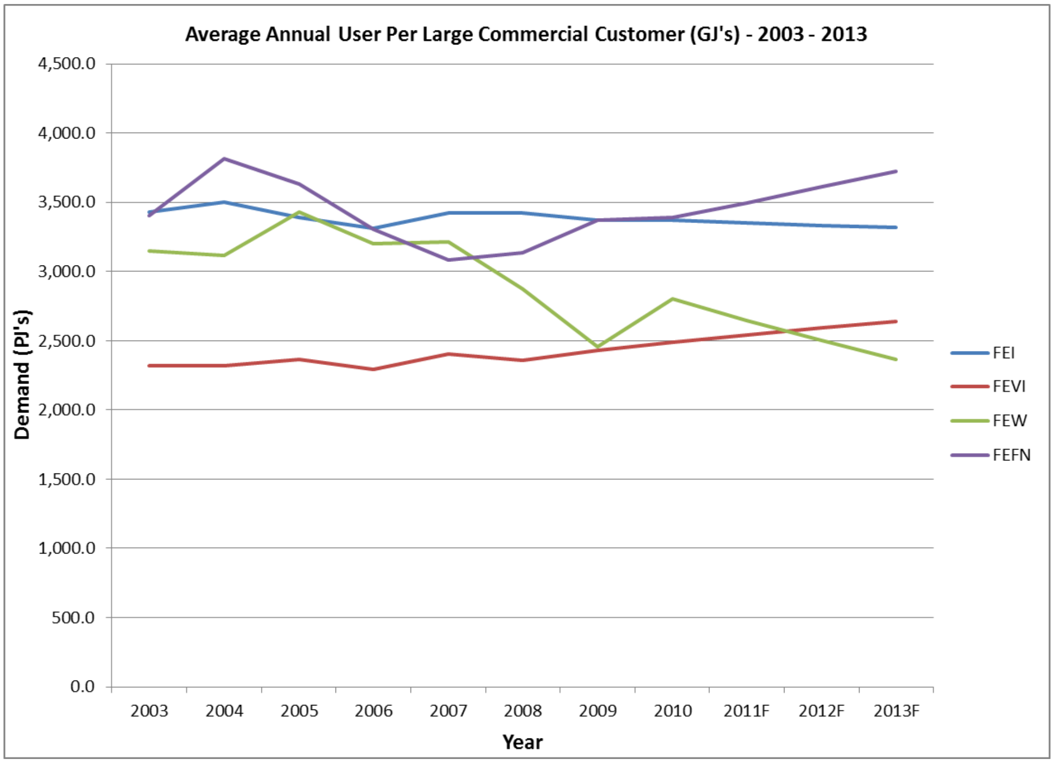
The figure shows that average use rates have fallen for FEI and FEFN, while average use rates for FEVI and FEW have experienced an increase. Similar to FEW's residential customer class, the system conversion to natural gas enabled Small Commercial class customers to adopt natural gas as their primary energy source. However, there were no new additions to FEW's Small Commercial class in 2010 and modest increases are forecast in coming years.

While average use rates for FEVI and FEW increased, these two utilities account for a small percentage of all Small Commercial customers. From 2003 to 2013, Small Commercial customers in FEI and FEFN experienced a 12.8 per cent decrease in these two regions.

Large Commercial Customers

The figure below presents the historical normalized average use rates for the Large Commercial customer rate class for each of the four utilities.

Figure 4-6: Overall Actual Average Large Commercial UPC (GJ/yr)g



The figure shows that average use rates have fallen for FEI and FEW customers, while average use rates for FEVI and FEFN have seen an increase since 2009. FEI customers, who account for the majority of Large Commercial customers, have experienced a 2.2 per cent decrease in average annual use per customer rates from 2003 to 2011, while FEW customers have experienced a 16 per cent decrease on average.

Summary of Average Use Rates

The table below shows the average use rates for the residential, small commercial and large commercial rate classes in FEI, FEVI, FEW and FEFN from 2003-2013.

Table 4-3: Average Use Rates 2003 - 2013

FEI	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	104.8	102.6	97.2	96.8	96.0	92.5	93.3	92.6	91.7	90.8	89.9
Rate 2	321.2	313.8	305.8	314.3	316.5	312.2	320.6	311.3	309.6	308.0	306.4
Rate 3	3,428	3,501	3,388	3,314	3,426	3,420	3,372	3,370	3,352	3,334	3,316
Rate 23	5,015	5,113	4,714	4,686	4,778	4,698	4,886	4,850	4,875	4,901	4,926

FEVI	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
RGS	60.3	57.5	57.3	60.2	57.0	56.1	53.5	52.4	50.5	48.6	46.9
SCS1	66.2	63.7	70.0	75.1	90.7	102.6	110.1	101.1	105.7	110.1	114.7
SCS2	295.8	284.9	303.4	313.8	310.3	313.0	325.4	330.2	338.8	347.0	355.5
LCS1	898.5	882.5	926.4	903.2	943.1	952.0	979.7	997.1	1,023.4	1,048.7	1,074.6
LCS2	2,319.4	2,318.3	2,365.1	2,295.4	2,406.0	2,359.0	2,430.4	2,490.4	2,542.0	2,591.2	2,641.4
AGS	1,243.9	1,402.3	1,350.4	1,387.1	1,366.7	1,297.0	1,260.9	1,300.8	1,283.4	1,264.0	1,244.9
LCS3	16,476.5	16,650.4	16,630.0	17,378.9	17,694.3	16,521.0	15,793.3	16,342.2	16,342.0	16,342.0	16,342.0

FEW	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
SGS-R	71.5	70.8	71.3	85.6	95.7	95.2	82.6	99.5	101.7	104.0	106.3
SGS-C	68.0	83.5	94.1	218.6	265.1	308.2	251.0	338.0	374.5	414.9	459.7
LGS-1	1,079.6	1,108.4	1,159.2	1,149.6	1,284.7	1,308.7	1,185.3	1,595.3	1,658.7	1,724.5	1,793.0
LGS-2	3,151.4	3,114.7	3,430.0	3,203.7	3,214.1	2,874.2	2,454.4	2,802.6	2,647.2	2,500.3	2,361.6
LGS-3	13,015.7	13,403.4	12,889.3	13,092.6	11,853.0	10,972.0	9,174.7	8,872.2	7,409.2	6,187.4	5,167.1

FEFN	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	162.3	155.1	153.7	141.5	141.9	139.6	138.4	140.9	140.6	140.3	140.0
Rate 2.1	563.6	537.3	502.1	486.5	472.0	448.9	464.0	468.1	467.2	466.2	465.2
Rate 2.2	3,404.2	3,814.7	3,634.5	3,302.8	3,083.7	3,137.1	3,370.7	3,387.5	3,496.7	3,609.4	3,725.7

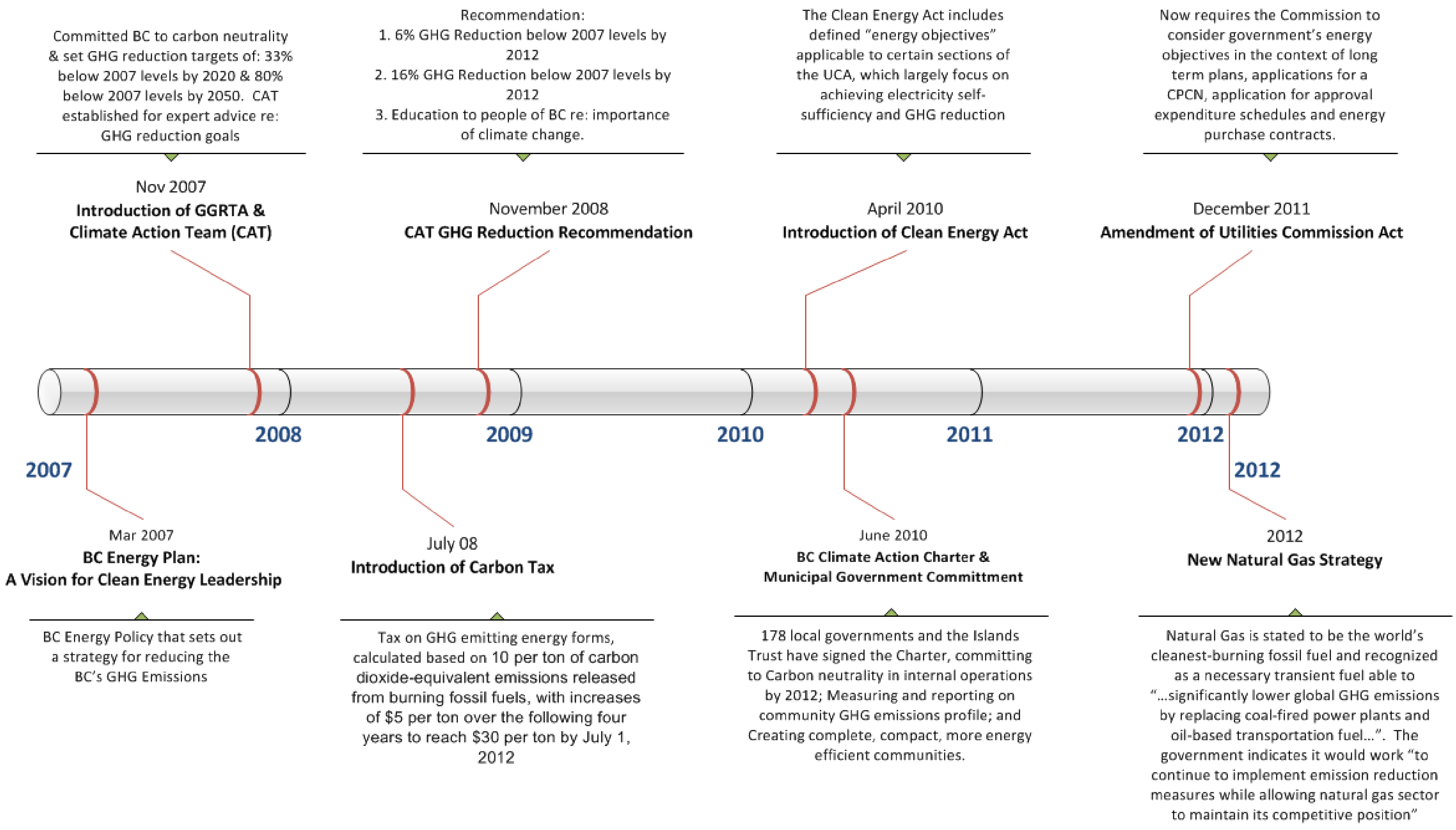
Average use per customer is a significant variable in determining total energy demand. Coupled with a slowing customer growth rate, these two factors will lead to lower total energy demand, which subsequently will result in increased rates for existing customers.

4.1.4 GOVERNMENT POLICY AFFECTS NATURAL GAS USE

One of the factors contributing to the trends discussed above is government energy policy. In this section, a summary of the key policy and legislative developments in British Columbia is presented.

Figure 4-7 below illustrates the key policies and legislative developments in chronological order. These key policy objectives related to GHG emission reductions have the effect of reducing throughput for FEU. While factors that reduce throughput affect all of the FEU today, the reduced throughput has a larger impact on FEVI and FEW due to their existing higher rates relative to FEI.

Figure 4-7: Key Policy and Legislative Developments Timeline



The legislation and policy initiatives enacted in BC shown above, such as GHG reduction targets and the carbon tax, can impact throughput for the FEU by potentially hindering the FEU's ability to attract new customers and retain its existing customer base. Overall since 2007, government's energy and climate change policies have shaped the energy choices for consumers away from natural gas in BC. For further discussion of these energy policies, please see the attached Appendices G-0 through G-9.

4.1.5 CUSTOMER PREFERENCES AFFECT NATURAL GAS USE

To delve further into the trends in total demand, the following provides analysis of residential natural gas end-use preferences and characteristics. As per Table 4-1 above, Residential customers represent the largest customer group for the FEU, consuming approximately 75 million GJs in.2010 An analysis of commercial and industrial customer characteristics is included in Appendices G-17 (for summary), G-14 and G-15 for commercial customer characteristics, and G-16 for industrial customer characteristics.

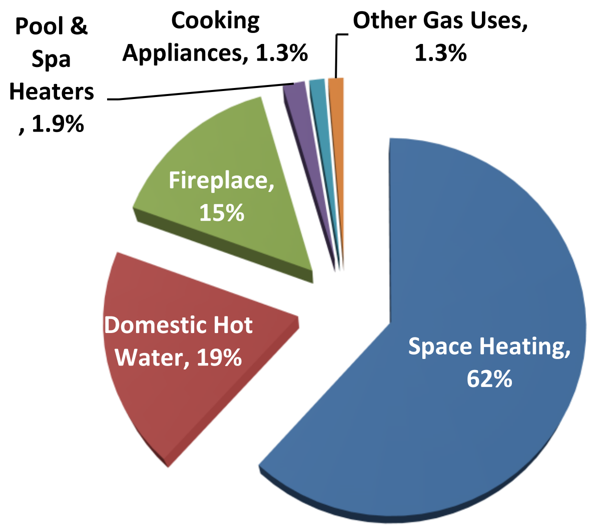
According to the 2010 Conservation Potential Review[85] (CPR) and the 2008 Residential End-Use Study[86] (REUS), the following represent the main end uses for natural gas in order of high to low use:

1. Space Heating
2. Domestic Hot Water (DHW)
3. Fireplaces
4. Cooking Appliances
5. Swimming pool and Spa Heaters
6. Other Gas Use

Figure 4-8 below illustrates the proportion of natural gas consumption distribution by end- use.

[85] See Appendix G-12
[86] See Appendix G-10

Figure 4-8: Residential Natural Gas Consumption Distribution by End-Use[87]



An analysis of the characteristics of space heating and domestic hot water, which make up approximately 81% of total residential natural gas use for the existing housing stock, is provided below. For a comprehensive analysis of all end-use types, see the 2008 REUS, 2010 Residential New Construction Research[88] (RNHS) and 2010 CPR studies found in appendix G-10, G-11 and G-12 respectively (electronically filed).

Space Heating

In 2008, 91% of the FEU's residential customer base used natural gas as the main space heating fuel. Regionally, Table 4-4 below indicates the lowest proportion of homes using natural gas as the main space heating fuel is within FEVI and FEW.

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87 See Appendix G-12: ICF Marbek. *Conservation Potential Review - 2010 Residential Sector Energy-efficiency, Alternative Energy & Customer Behaviour Opportunities.* Ottawa: ICF Marbek, 2011. p. v

88 See Appendix G-11: The RHNS is a quantitative survey produced by Sampson Research in 2011 that surveyed homeowners of residential dwellings constructed between 2006 and 2010 about their dwelling's construction characteristics, space and domestic water heating fuels and equipment, gas and electric appliances, and other natural gas end-uses.

Table 4-4: Survey Results - Main Space Heating Fuel by Region (2008)89

Main Space Heating Fuel	FEI	FEVI	FEW	FEFN	FEU
Electricity	4.7%	26.3%	29.5%	2.9%	6.9%
Natural Gas	93.6%	70.5%	15.2%	94.2%	91.1%
Piped propane	0.2%	0.8%	52.4%***	--	0.4%
Bottled Propane	0.1%	--	--	--	0.1%
Oil	0.0%	1.6%	--	--	0.2%
Wood	0.9%	0.5%	2.0%	0.7%	0.9%
Other	0.2%	0.3%	--	--	0.2%
DK[1]	0.3%	0.0%	0.9%	2.2	0.2%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

1 – DK = "Don't know" response

** Totals may not sum due to rounding

*** As Whistler was recently converted to Natural Gas from Propane, some Whistler respondents were confused of which type of gas they utilized.

** Totals may not sum due to rounding

The use of natural gas as a main space heating fuel is diminishing due to the rise in use of electricity as a main heating fuel. According to the 2010 RNHS, new homes with gas service are less likely to use natural gas as a main space heating fuel and more likely to use electricity compared to the stock of gas homes built prior to 2006. Most notably:[90]

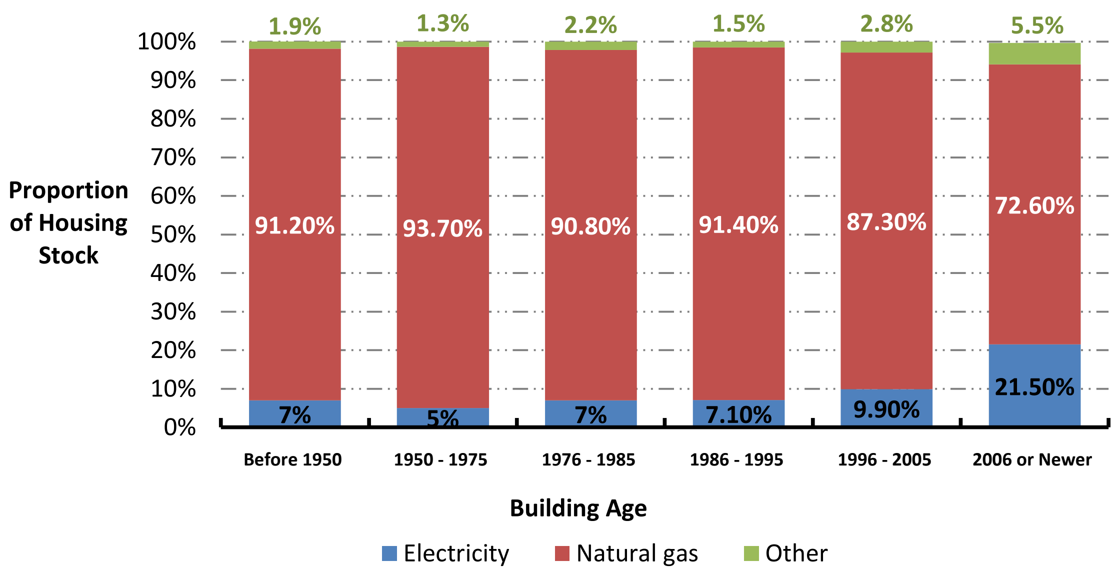
1. Regardless of dwelling type, 22% of gas connected homes built since 2005 use electricity as its main space heating fuel compared to 6.9% of homes built prior to this date.
2. Of all gas connected homes built since 2005, natural gas is used as the main space heating fuel for only 73% of the homes compared to 92% of homes built prior to 2006.
3. On Vancouver Island, only 32% (lowest of all regions) of new homes constructed used natural gas as its main space heating fuel compared to 70% of homes built prior to 2006.
4. On the Lower Mainland, which includes Whistler in the study, 80% of new homes constructed used natural gas as its main space heating compared to 94% of homes built prior to 2006.

Figure 4-9 below illustrates the main space heating fuel trend by dwelling age.

89 See Appendix G-10: Sampson Research. *2008 Residential End Use Study.* Robson Creek: Sampson Research, 2009. p. 5-1

90 See Appendix G-11 2010 RHNS p. 28

Figure 4-9: Natural Gas Use for Space Heating on the Decline since 1950



The share of natural gas heated homes with respect to homes built since 2005 has eroded in light of increasing use of other energy forms, primarily electricity. As previously indicated, Vancouver Island had the lowest proportion of new homes constructed connected to natural gas that uses natural gas for space heating. The Lower Mainland region, including Whistler has also seen drops in new homes constructed connected to natural gas that uses natural gas for space heating. This drop in load growth will further exert upward pressure on rates for all utilities. This adds an additional challenge to FEVI and FEW, which already have higher rates.

Domestic Water Heating

Domestic water heating constitutes the second largest share of natural gas for residential customers, accounting for 19% of total residential natural gas use. Penetration rates of domestic water heaters (DWH) in 2008 were high across all entities. From 96% to 99% of all homes connected to the natural gas system had DWHs. Table 4-5 below summarizes the hot water heater fuel by region.

Table 4-5: Hot Water Heater Fuel by Region - First Unit (2008)[91]

Fuel for First Water Heater	FEI	FEVI	FEW	FEFN	FEU
Electricity	9.7%	20.0%	43.5%	12.8%	10.8%
Natural gas	90.1%	79.5%	12.1%	87.2%	88.8%
Piped propane	0.0%*	0.3%	44.0%**	--	0.1%
Other	0.2%	0.3%	0.5%	--	0.2%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

* *Value smaller than 0.1%

[91] See Appendix G-10: 2008 REUS p. 7-3

** As Whistler was recently converted to Natural Gas from Propane, some Whistler respondents were confused of which type of gas they utilized.

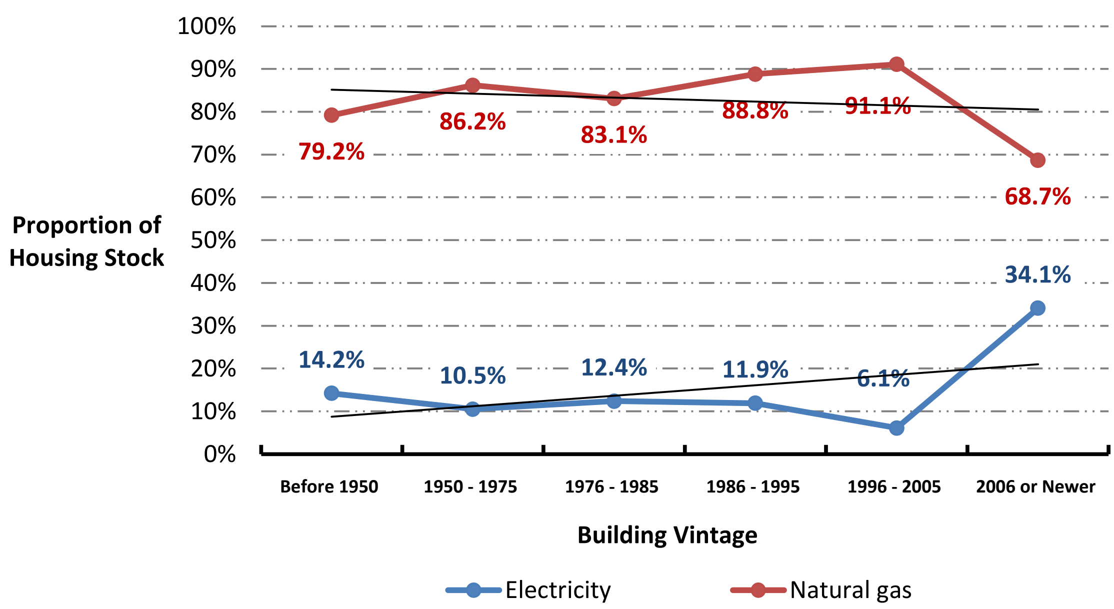
As table 4-5 indicates, FEVI and FEW had the lowest proportion of homes with natural gas fired DWHs.

Like the use of natural gas for space heating, the use of natural gas fired DWHs is diminishing due to the rise in use of electricity heated DWHs. According to the 2010 RNHS,[92] new homes with gas service are less likely to use natural gas fired DWHs and more likely to use electricity compared to the stock of gas homes built prior to 2006. Most notably:[93]

- Of the homes built since 2005, only 69% of those with gas service had a domestic hot water heater, compared to 35% that use electrically heated DHWs.
- On Vancouver Island, 49% of those with gas service used natural gas fired DWHs, compared to 56% that use electrically heated DWHs.
- On the Lower Mainland, which includes Whistler, only 80% of those with gas service used natural gas fired DWHs, compared to 27% that use electrically heated DWHs.

Figure 4-10 below illustrates the trend in DHW fuel by dwelling age.

Figure 4-10: Trend in Domestic Water Heating Fuel by Dwelling Vintage (2008)[94]



**Numbers not additive because some homes may have more than one DWH fuel

92 See Appendix G-44
93 See Appendix G-11: 2010 RHNS, p. 47 – data is not additive because some homes may have more than 1 DHW
94 See Appendix G-11: 2010 RNHS p. 48

Vancouver Island and the Lower Mainland region, which includes Whistler in this study, are seeing drops in new homes constructed connected to natural gas that use natural gas fired DWHs. Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulation (i.e. changes in building codes) for gas furnaces such as the requirement to install more costly high efficiency units, which is a result of factors such as the government's energy policies related to GHG reduction. If customers are not installing gas furnaces, they are much less likely to install a gas water heater. As such, the relative cost disadvantage of installing a gas water heater as opposed to an electric water heater contributed to the decline in use of natural gas. Additionally, because a natural gas water heater requires venting, the loss of interior space to accommodate venting factors in on whether or not to install the already more expensive natural gas units.

As space heating and domestic hot water heating together account for 81% of total residential natural gas consumption, the declining trends discussed above will negatively impact throughput and load growth. This has the potential effect of exerting upward pressure on rates, which would be more challenging for FEVI and FEW, which already have higher rates.

4.1.6 SUMMARY OF NATURAL GAS DEMAND USE & RATES

FEU has seen an overall decline in energy demand from the industrial sector. For residential and commercial customers, total energy demand has been relatively flat. This flat energy demand is influenced by declines in both commercial and residential average use per customer rates that have offset the throughput gained from net residential and commercial customer additions. This will likely continue given that the factors contributing to the decline in use per customer rates, such as government policy, demand-side management programs and the shift in the housing mix, are likely to continue,

4.2 Issue #1: The Existing Rate Discrepancy

A key issue that faces the FEU is that although the vast majority of its customers have the same rates, the service areas of FEVI and FEW have much higher rates and Fort Nelson customers have much lower rates, when compared to the Lower Mainland, Inland and Columbia service areas. Given the common ownership of the FEU, as well as changes in FEVI's circumstances, FEU believe there is no longer any justification for retaining the current regional differences.

The existing rates for the FEU are reviewed in detail in section 3. These rates are summarized in the table below:

Table 4-6: Rates for the FEUs Service Areas

	FEI (LM)	FEI (Inland)	FEI (Columbia)	FEVI[1]	FEW[2]	FEFN[3]
Basic Charge (per day)	$0.3890	$0.3890	$0.3890	$0.3450	$0.2464	*$0.3184**
Delivery Charge ($/GJ)	$3.881	$3.881	$3.881	*$7.872**	$11.686	$2.443
Midstream Charge ($/GJ)	$1.402	$1.367	$1.411	*$1.384**	*$1.107**	*$0.276**
Cost of Gas ($/GJ)	$3.997	$3.997	$3.997	*$5.069**	*$3.997**	*$3.920**

* *Proxy Charges* – As a basis for comparison, a proxy charge has been developed for the bundled charges of FEVI FEW and FEFN
[1] FEVI has an 'Energy charge' that bundles the Delivery, Midstream and Cost of Gas charges together
[2] FEW has a 'Cost of Gas' Charge that bundles Midstream and Commodity charges together
[3] FEFN has a Minimum Daily Charge. A proxy basic reflecting only the delivery component of the minimum daily charge is shown here. Also, FEFN has 'Cost of Gas' charge that bundles the Midstream and Cost of Gas Charge together.
***Table excludes all Riders

As seen in the table above, customers in the Lower Mainland, Inland and Columbia service areas enjoy the same delivery and commodity rates and minimal differences in their midstream rates. The vast majority of FEU's customers, approximately 850,000 of the FEU's 956,000 customers, are effectively paying common rates. The postage stamping of rates within the FEU's largest service areas reflects the most widely accepted practice in the utility industry and the rate design approved by the Commission for most utilities in BC. In particular, postage stamp rates are consistent with the rates approved for the electrical utilities in the Province, namely, BC Hydro and FBC. Postage stamp rates allow the pooling of all costs for the benefit of all customers. The FEU believe that postage stamp rates are the most appropriate rate structure for public utility services.

As shown in the table above, however, the smaller service areas of FEW, FEVI and Fort Nelson pay different rates than the majority of FEU's customers in the Lower Mainland, Inland and Columbia service areas. These service areas also do not have access to all of the natural gas services offered by the FEU. As discussed in section 3, the reason for this disparity is the FEU's history of growth through acquisition. Given that the FEU have been under common ownership since 2002, however, the move to amalgamation of the FEU and the implementation of common rates is the logical next step for the FEU.

While the FEU have been under common ownership since 2002, there are a number of reasons why it has not been practical to implement common rates until now. The primary reason for this arises from the history of natural gas service on Vancouver Island. As discussed in section 3, since 1996 the rates for FEVI have been governed by the VINGPA and VINGPA Special Direction. This structure is complex and has included government subsidies in the form of Royalty Revenues and repayable contributions designed to assist with the financial viability of the Vancouver Island system. While this structure was in place, it would not have been appropriate to amalgamate. For instance, the VINGPA Special Direction authorized the creation of the RDDA and, by the time FEVI came under common ownership in 2002, a large revenue deficiency had accumulated in the account.

Since 2002, FEVI has sought to bring down the balance in the RDDA and has succeeded in paying off the deficiency and accumulating a revenue surplus which it has collected in the RSDA. This surplus can now be used to offset the rate impact of amalgamation. In addition, the Royalty Revenues provided by the Province used to mitigate the costs of natural gas have recently ceased. In short, the existing framework governing the rates of FEVI for the past 16 years has come to an end. FEVI has been left in a favourable position to amalgamate with FEI and FEW. At the same time, FEW has been converted from a propane to a natural gas system, facilitating the adoption of common delivery, midstream and commodity rates. It is therefore an opportune time for the FEU to amalgamate and implement common rates for all customers of the FEU across the Province.

The rationale for common rates exists even though it means higher rates for some customers. For customers of FEI, it may be argued that the current differential in rates between the service areas reflects regional differences in cost of service. However, it is difficult to justify the continued rate disparity given the precedent of postage stamp rates in the Province and the variations in cost of service within postage-stamped service areas of the FEU already. As stated by EES Consulting:[95]

> *In reality, each customer on the system has a slightly different cost of service based on when they were connected, the location of the customer, the overall energy use, the load profile of the customer, etc. However, it would be impossible to set separate rates for each individual customer. For that reason customers are grouped into rate classes to reflect differences in usage patterns and connection costs. The question then becomes how far to carry the averaging of costs between customers on the basis of location. While there may be regional differences in costs, there are also differences in costs based on each customer's unique location on the system. We do not find it to be equitable to differentiate customer rates on the basis of broad regional differences while not differentiating on the basis of a more specific location or other factors.*

Thus, while there are differences in cost of service between regions, there are also differences within the current service areas and throughout the entire natural gas service area. Differences exist based on such factors as when a customer connects to the system, how close a customer is to transmission pipeline delivery points, geographical terrain and residential density. Just as there is no logic to creating separate classes of customers based on each of these factors, it is difficult to justify continuing historical service areas that need no longer be maintained. Overall,

[95] Appendix D-1 EES Cost of Service Summary Report, EES Consulting, "FEU Natural Gas Cost of Service Review", p. 5.

it is fairer that all customers in the same class pay the same rate, no matter where they happen to reside.

The rate discrepancies within the FEU and operating trends affecting the FEU are particularly challenging for FEVI and FEW. As noted above, FEVI and FEW currently have much higher rates than FEI. Based on 2013 proposed effective rates for typical residential customers in the absence of amalgamation, customers located in FEVI's and FEW's service areas will be paying 45 percent and 64 percent higher than FEI as shown in Table 4-7 below.

Table 4-7: FEVI and FEW Customers Pay More for Natural Gas[96]

FEI (LM)	FEI (Inland)	FEI (Columbia)	FEVI	FEW	FEFN
$10.859/GJ	$10.824/GJ	$10.868/GJ	$ 15.725/GJ	$17.850/GJ	$7.280/GJ

Because of these higher rates, the operating trends being experienced by the FEU (namely challenges in increasing total demand) pose more of a problem for FEVI and FEW than for FEI. Failing to address the rate discrepancies will make it more challenging for FEVI and FEW to increase their customer bases and retain existing customers.

4.3 Issue #2: Cost Pressures for FEVI: Loss of Government Subsidies

In addition to the trends affecting all of the FEU, FEVI faces other factors that will increase the rate discrepancy that currently exists between it and the service areas of FEI. These factors are the loss of the Royalty Revenues for FEVI on December 31, 2011, and the repayment of the federal/provincial repayable contributions that will continue to increase rate base in the future. Each of these is discussed below.

Royalty Revenues

As discussed previously, FEVI faces upward pressure on rates due to the cessation of the Royalty Revenues on December 31, 2011. The Royalty Revenue payment from the Province was based on wellhead natural gas prices, and therefore the actual revenue received from year to year was subject to swings in the commodity markets. In the last few years, this has ranged from approximately $44.6 million[97] in 2008 to approximately $17.3[98] million in 2011, reflecting the shifts in natural gas markets over that period.

96 For purposes of calculating effective rates, typical customer consumption is assumed to be 90GJ. 90GJ reflects the average residential use rate across the FEU. The calculations are based on burner-tip excluding taxes, fees and riders. Please see Appendix J-1 for detailed calculations. The existing differences across Inland, Columbia and Lower Mainland services areas of FEI are due to different midstream rates. The FEU have proposed effective residential rates as of January 1, 2014 using the 2013 test year numbers.

97 Figure includes 2008 payment plus 2009 true-up

98 $17.3 million Royalty Revenue is the 2011 forecast amount in the Q4 Gas Cost Report filed November 18, 2011 with the Commission

Repayment of Federal and Provincial Repayable Contributions

As part of the 1996 reorganization, the Federal and Provincial Governments provided FEVI with repayable loans in the amounts of $50 million and $25 million, respectively. The loans were provided to construct the Vancouver Island pipeline and intended to help FEVI establish a cost-effective natural gas energy source for Vancouver Island customers. Pursuant to Article 5 of the Pacific Coast Energy Pipeline Agreement, the loans are to be repaid, with initial repayment amounts tied to the balance in the RDDA. The repayment will result in an increase to the revenue deficiency of $2.1 million by 2016 as compared to 2013.

Implications of the Loss of Government Subsidies

On a stand-alone basis, the deficiency in revenues resulting from the expiration of the government subsidies must be mitigated by increased volumes, or customer rates will increase. In order to mitigate the loss of the Royalty Revenues and the contribution repayments by increasing volume, FEVI would have to either increase net customer additions or increase UPC rates from its existing customer base. To address these issues, the FEU are working toward increasing volume throughput through the development of new services such as NGT, increased fuel switching from high carbon to lower carbon options, and new industrial loads. Targeting increased volume throughput from these initiatives will continue to be pursued as it will benefit customers whether or not amalgamation proceeds. However, increasing customer additions or UPC rates on FEVI by an amount sufficient to mitigate the loss of government subsidies for 2014 (or over five years with the amortization of the RSDA) would be challenging given the current trends.

FEVI's alternative is to increase the delivery rates charged to customers to recover the loss of the government subsidies. Although a positive RSDA balance exists[99] that could be returned to FEVI customers to mitigate the initial rate increase as a result of the loss Royalty Revenue, it would only be a temporary measure. Based on current expectations, if the RSDA were fully re-distributed to FEVI customers beginning in 2013, the RSDA balance would be depleted by 2017[100], leaving FEVI customers facing the same situation that exists today. Once the balance is depleted, FEVI customers would face a rate increase in the range of 20% as shown in Section 6, Figure 6-1. This would add to the current rate difference that exists between FEVI and the service areas of FEI.

As such, the negative impact on FEVI customers of increasing their delivery rates to address the loss of government subsidies presents a challenge for FEVI. The FEU are seeking a lasting solution that will address the pressures facing FEVI.

[99] The projected December 31, 2012 surplus RSDA balance is $79.6 million (before tax)
[100] See Section 6, Table 6-2

4.4 Issue #3: Smaller Utilities are Susceptible to Long Term Rate Instability

A third issue confronting the FEU is that FEVI, FEW and FEFN are more susceptible to rate volatility in response to changes in throughput and large capital expenditures than FEI (Mainland). There are two main factors that lead to rate instability in the FEU's smaller utilities:

1. The high rate base per customer ratio that exists for FEVI and FEW and the resulting susceptibility to the impact of localized capital investment requirements; and
2. FEVI, FEW and FEFN's reliance on a small, undiversified customer base.

The interplay of these factors leads to the potential for long-term rate instability for FEVI, FEW and FEFN.

High Rate Base per Customer

FEW and FEVI each have a higher rate base per customer when compared to FEI (Mainland). A utility with a higher rate base per customer is required to recover its fixed costs from a smaller customer base and on a relatively lower throughput, which translates into higher rates for FEVI and FEW, as shown in the following table, which presents both the rate base per customer and current 2013 proposed effective rates for typical residential customers.

Table 4-8: FEVI and FEW Customers Pay More for Natural Gas101

FEI		FEVI		FEW	
Rate Base per Customer[1]	Effective Rate[2]	Rate Base per Customer	Effective Rate	Rate Base per Customer	Effective Rate
$3,269	$10.859/GJ	$7,669	$15.725/GJ	$15,727	$17.850/GJ

1 Excludes Fort Nelson

2 Lower Mainland Rate

As shown in Table 4-8 FEVI's and FEW's rate base per customer are significantly higher than FEI's (note that FEFN does not currently have the same issue). Because FEVI and FEW have a significantly higher rate base per customer when compared to FEI, their rates are more susceptible to the impact of the implementation of large capital projects. Therefore FEVI and FEW's small customer base makes them susceptible to potentially significant rate increases from localized investments.

For FEVI, FEW and FEFN, the impact of localized investments is accentuated, both in potential significant increases in rates and also for long-term rate stability. For instance, the Muskwa

101 For purposes of calculating effective rates, typical customer consumption is assumed to be 90GJ. 90GJ reflects the average residential use rate across the FEU. The calculations are based on burner-tip excluding taxes, fees and riders. Please see Appendix J-1 for detailed calculations. The existing differences across Inland, Columbia and Lower Mainland services areas of FEI are due to different midstream rates. The FEU have proposed effective residential rates as of January 1, 2014 using the 2013 test year numbers.

River Crossing upgrade in Fort Nelson, discussed in the 2012-2013 RRA[102] and forecast at $3.1 million, provides an example of how localized investments can impact rates for utilities with small customer bases. The Muskwa River Crossing is the main driver behind the growth in Fort Nelson's rate base from $5.4 million in 2010 to a forecast of $9.3 million in 2013 (an approximate increase of 72 percent). The cost of service associated with the Muskwa River Crossing is approximately $260 thousand in 2013. All else equal, a cost of service increase of $260 thousand for Fort Nelson results in an increase to their delivery rate of approximately 13.7 percent,[103] or roughly a $54 increase to an average residential customer's annual bill.[104] In comparison, the cost of service associated with the Kootenay River Crossing (Shoreacres) project, forecast at $9.7 million for FEI, is approximately $709 thousand in 2013. All else equal, a cost of service increase of $709 thousand for FEI (Mainland) results in an increase to FEI (Mainland)'s delivery rate of approximately 0.13 percent, or roughly a $1[105] increase to an average residential customer's annual bill. As described in the CPCN for the Shoreacres project, approximately 5,200 customers located in the City of Nelson and its surrounding area are downstream of the crossing.[106] If the costs of the project were allocated only to those 5,200 customers it would result in a delivery rate increase of approximately 25 percent, or roughly a $110 increase to an average residential customer's annual bill.[107] The difference between the impacts of 0.13 percent and 25 percent exemplifies the benefit of a larger customer base with respect to localized investments.

Reliance on a Small, Undiversified Customer Base

FEVI, FEW and FEFN are further challenged by having a less diverse customer base compared to that of FEI (Mainland). As illustrated in Table 4-10 below, the top 10 highest consuming FEVI customers account for approximately 63 percent of FEVI's total throughput and 16 percent of the total revenues. For FEW, this ratio is 18 percent of total throughput and 21 percent of total revenues, whereas for FEFN this ratio is 17% of total throughput and 11% of total revenue. This suggests that the loss of a major customer for one of these smaller utilities would have a material impact on both throughput and revenue. Therefore, FEVI's, FEW's and FEFN's reliance on a relatively few customers makes them more susceptible to fluctuations in throughput in the case of customer loss. In comparison, FEI has a more balanced ratio; the top

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102 FEU 2012-2013 RRA Appendix C-11, Evidentiary Update, July 19th, 2011, Exhibit B-11.

103 As compared to the 2011 approved Fort Nelson delivery rates, which included a partial year of the Muskwa River Crossing cost of service of approximately $90 thousand, the impact to the 2013 non-amalgamated Fort Nelson delivery rate is an increase of approximately 9% (($260 thousand 2013 COS - $90 thousand 2011 COS in approved rates)/$1,901 thousand 2013 gross margin at existing rates).

104 13.7% multiplied by the 2011 average approved residential delivery rate of $2.84 = $0.39 * 140 GJ average consumption for a residential customer

105 0.13% multiplied by the 2011 average approved FEI residential delivery rate of $4.77 = $0.0062 * 95 GJ average consumption for a residential customer

106 Exhibit B-1, Terasen Gas Inc. Application for a Certificate of Public Convenience and Necessity for the Kootenay River Crossing (Shoreacres) Project, Volume 1- Application, dated July 15, 2010, page 18

107 Impact for the 5,200 customers calculated using the average use rates and delivery rates for Mainland Rate 1, Rate 2 and Rate 3 as derived from Appendix H-1, Schedule 16. That is $709 thousand / (5,200 customers x average use rate for Residential and Commercial x average delivery rate for Residential and Commercial, where average use rate is equal to Schedule 16, Line 6, Column 2 divided by Column 9 x 1000 and average delivery rate is equal to Schedule 16, Line 6, Column 6 divided by Column 2.

10 consuming customers account for only 6 percent of total throughput and less than 1 percent of total revenues.

Table 4-9: Reliance on Large Customers in Smaller Utilities Compared to FEI

	Total Throughput in 2010 *(in TJs)*	Throughput - Top 10 Consuming Customers *(in TJs)*	Percentage of Top 10 to Total Throughput	Actual Total Revenue 2010[108] *(in $000)*	Revenue - Top 10 Consuming Customers *(in $000)*	Percentage of Top 10 to Total Revenue
FEVI	31,017	19,455	63%	$193,410	$31,125	16%
FEW	753	132	18%	$13,587	$2,883	21%
FEFN	615	102	17%	$4,846	$520	11%
FEI	161,133	9,971	6%	$1,311,002	$7,896	0.6%

Moreover, a heavy reliance on a relatively small number of customers to generate significant throughput is compounded when these customers are part of the same industry. For example, a recessionary economic cycle would have a significant adverse impact on natural gas consumption in Whistler, where nine out of the ten largest customers are tourism related enterprises. Tourism is a highly cyclical industry. When unfavorable economic cycles hit, a decline in consumption levels in the tourism industry is likely to put upward pressure on the delivery rates for all customers. Similarly, FEVI is highly dependent on industrial load from BC Hydro and the VIGJV.[109] These two customers account for approximately 15 percent of FEVI's gross margin (60 percent of the throughput). Any development that would reduce the throughput levels of these two industrial customers will have an adverse impact on the delivery rates for all the remaining customers.

Table 4-10 below illustrates the total annual bill impact in the event the top 10 consuming customers of each utility left the system. As the table indicates, FEW, FEVI and FEFN each would have significant total annual bill impacts, with increases estimated at $418, $158 and $142, respectively, for a typical residential customer. Conversely, if the top 10 consumers of FEI left the system, a typical FEI residential customer would only see a total annual bill increase of $5. As such FEVI, FEW and FEFN's reliance on a smaller, less diverse customer base compared to that of FEI jeopardizes the long term rate stability of the smaller utilities.

108 Non-normalized actual revenues for year-end 2010, excluding RSDA and RSAM related revenues.
109 The VIGJV was the main Shipper on the Vancouver Island Gas Pipeline when the Vancouver Island Gas Pipeline Project was completed and was formed by seven pulp mills to purchase transportation service from the new pipeline. Currently there are five pulp mills in operation.

Table 4-10: Potential Annual Bill Impacts on Remaining Customers with Loss of Large Customers [1]

	Revenue - Top 10 Consuming Customers *(in $000)*	Throughput - Non-Top 10 Consuming Customers *(in TJs)*	Average Revenue per GJ increase needed	Typical Residential Customer Average Consumption *(in GJs)*	Total Annual Bill Impact
	(1)	(2)	(3) = (1) / (2)	(4)	(5) = (3) * (4)
FEVI [2]	$ 31,125	11,562	$ 2.69	58.6	$ 157.75
FEW	$ 2,883	621	$ 4.64	90.0	$ 417.83
FEFN	$ 520	513	$ 1.01	140.0	$ 141.91
FEI	$ 7,896	151,162	$ 0.05	95.0	$ 4.96

[1]This analysis is done at a high level and does not include any potential impacts to costs that would impact the delivery margin.
[2] Analysis shows the impact in the absence of RSDA

Another example can be found in Fort Nelson. In its 2009 Revenue Requirement Application, the impact of Canfor closing its two plants in the Fort Nelson region was included in the 2009 forecasts. As forecast in that application, the impact of these closures was a revenue deficiency of $258 thousand,[110] or a 25% increase to delivery rates. Since that time, the two plants have been consuming natural gas for space heating only. It is anticipated that one of these two contracts will terminate in 2012,[111] resulting in a forecasted decrease of 13.9 TJs, or 2.2 per cent of total demand volumes. This decrease in system throughput will place upward pressure on rates for existing and potential Fort Nelson customers.

In sum, FEVI, FEW and FEFN's small customer base compared to that of FEI's jeopardizes the long term rate stability of these smaller entities, by making them susceptible to potentially significant rate increases from both localized investments and customer loss. Should significant load loss or localized investments occur, the result will be an increase in the rate disparity that currently exists across the FEU.

4.5 Summary

As discussed above, the issues faced by the FEU that this Application seeks to address include:

- The rate disparity that exist across the FEU. The result of the FEU's historical growth through acquisition is an overly complex system of three legal entities, four rate bases and six services areas. Despite the common ownership of the FEU and the prevalence of postage stamp rates, a minority of FEU customers pay different rates and receive different services based on where they reside in the Province. Changing customer preferences and user characteristics have the consequence of making it more challenging to increase total demand. For FEVI and FEW, this is more of a challenge

[110] Page 3 of the cover letter for the 2009 TG Fort Nelson Revenue Requirement Amended Application.
[111] http://www.canfor.com/media-center/news-press-releases/2011/12/05/canfor-announces-permanent-closure-of-rustad-and-tackama-operations

due to their existing higher rates and could lead to a wider rate discrepancy across the FEU's service areas.

- The loss of government subsidies for FEVI. Customers located in FEVI's service area already pay more for natural gas service than similar customers on FEI's system. To make up for the loss of government subsidies, FEVI will be required to increase its rates in the range of 20% in order to recover its cost of service, further increasing this rate disparity. However, the significant negative impact to FEVI customer rates results in this not being a practical solution.
- The long-term rate instability of smaller service areas. FEVI, FEW and FEFN are currently susceptible to long term rate instability due to their reliance on smaller, and less diverse customer bases as compared to that of FEI.

Therefore, the FEU are proposing a solution that can adequately resolve the current rate and service offerings disparity across the FEU, which will in turn also address the impact of the cessation of the government subsidies on FEVI, and the risk of long term rate instability for FEVI, FEW and FEFN.

5 REVIEW OF OPTIONS

5.1 Introduction

Based on the issues discussed in section 4, the FEU determined that its objectives are to achieve the following:

- Minimize the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW.
- Implement a long-term solution for FEVI customers to the loss of the government subsidies and associated rate impacts;
- Provide long-term rate stability for all customers; and
- Mitigate any significant increases to customers' rates.

The approach that best achieves these objectives for the majority of our customers is to:

1. Amalgamate the FEU;
2. Implement common rates; and
3. Implement rate mitigation strategies to address any significant rate increases.

In this section the FEU compare this solution to other options that address some or all of the FEU's stated objectives. The review supports FEU's position that amalgamation and postage stamp rates is the preferred solution.

The following sections discuss the five step option review undertaken by the FEU and then describes each of the five steps in detail.

5.2 Option Review Framework

The FEU's proposal to address its key objectives is to amalgamate and move to common rates. To support our view that there are no other options that better achieve the objectives, the FEU reviewed other alternatives using a five-step approach, using both qualitative and quantitative frameworks. The five steps are described below:

1. Identify options and group the options according to like characteristics;
2. Identify the qualitative objectives to be used to review the options;
3. Review the options using a qualitative approach, including identifying certain options for further quantitative review;
4. Identify desired quantitative objectives;
5. Quantitative review of those options.

Figure 5-1 summarizes the 5-step review.

Figure 5-1: Summary of Five Step Options Review

1) Identification and Grouping of Options	2) Identification of the Qualitative Objectives	3) Initial Review Against Qualitative Objectives	4) Identification of Quantitative Objectives	5) Quantitative Review of Options
Option Groups	Qualitative Comparator	Option Groups	Quantitative Comparator	Option Groups
A Status Quo	1 Minimize Rate Differences		1 Rate Differences	
B Status Quo with Common Commodity and Midstream Rates	2 Address the Revenue Deficiency for FEVI		2 Unit Cost of Service	
C Amalgamation or Consolidation of One or More Existing Rate Bases with FEI, with One or Two of Existing Rate Bases Remaining as is	3 Provide Long Term Rate Stability	C-1 Amalgamation or Consolidation of One or More Existing Rate Bases with FEI, with One or Two of Existing Rate Bases Remaining as is	3 Revenue to Cost Ratio	
D Amalgamation of the Three Legal Entities into One Legal Entity; Six Service Areas Maintained; Common Commodity and Delivery Rates with Regional Midstream Rates Implemented	4 Mitigate Rate Impact on FEI (Mainland) Customers	D Amalgamation of the Three Legal Entities into One Legal Entity; Six Service Areas Maintained; Common Commodity and Delivery Rates with Regional Midstream Rates Implemented		
E Amalgamation of the Three Legal Entities into One Legal Entity; New Service Areas Created with Common Commodity and Midstream Rates and Regional Delivery Rates	5 Mitigate Rate Impact on Fort Nelson Customers	E Amalgamation of the Three Legal Entities into One Legal Entity; New Service Areas Created with Common Commodity and Midstream Rates and Regional Delivery Rates		
F Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream And Delivery Rates		F Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream And Delivery Rates		F Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream And Delivery Rates

5.3 Step One - Identification and grouping of the options

The first step in the process was to identify a number of alternatives to be considered. In identifying alternatives the FEU did not consider any that would increase the number or complexities of existing rate differences. The Companies identified six option groups involving different combinations of legal amalgamation, rate base and cost of service consolidation, and common rate components, including maintaining the status quo.

The six option groups are described below:

A. *Status Quo*
No change from the legal or regulatory rate structures in place presently for each of the four utilities. The four utilities remain in place with their existing rate structures and service offerings. The rate bases, revenue requirements and gas cost portfolios would remain as is.

B. *Status Quo with Common Commodity and Midstream Rates*
The delivery rates for each of the four utilities remain in place. However, the gas cost portfolios would be consolidated and the commodity and midstream rates would be postage stamped across the six service areas.

C. *Amalgamation or Consolidation of One or More Existing Rate Bases with FEI , with One or Two of Existing Rate Bases Remaining As Is*
This option group contains six options that involve common rates for various amalgamation or consolidation scenarios as summarised below:

- C-1: FEI, FEVI and FEW amalgamate, Fort Nelson remains as-is
- C-2: FEI and FEVI amalgamate, FEW remains as-is
- C-3: FEI and FEW amalgamate, FEVI remains as-is
- C-4: FEI and FEVI amalgamate, FEW and Fort Nelson remain as-is
- C-5: FEI and FEW amalgamate, FEVI and Fort Nelson remain as-is
- C-6: FEI and Fort Nelson consolidated, FEVI and FEW remain as-is

D. *Amalgamation of the Three Legal Entities into One Legal Entity; Six Service Areas Maintained; Common Commodity and Delivery Rates with Regional Midstream Rates*
This option group involves the legal amalgamation of the three entities, and the consolidation of the rate bases and revenue requirements. The FEU would combine the entities' gas cost portfolios and develop a common commodity rate while maintaining regional midstream rates across the existing six service areas. Delivery rates would be common across the service areas using FEI's rate structures.

E. *Amalgamation of the Three Legal Entities into One Legal Entity; New Service Areas Created with Common Commodity and Midstream Rates and Regional Delivery Rates*
This option group involves the legal amalgamation of the three entities, and the consolidation of the rate bases and revenue requirements. Two new service areas would be formed from the existing six service areas based on regional proximity. For the purpose of this analysis, the FEU developed what it believes to be the most logical redefinition of service areas upon amalgamation, utilizing the existing six service areas:

- The first region would be a combination of the FEI Lower Mainland Region with FEVI and FEW (the "West Region").
- The second region would involve the combination of the FEI Inland Region, the FEI Columbia Region and Fort Nelson (the "East Region").

The associated rate bases and revenue requirements for the new service areas would be developed based upon adding the existing service areas' rate bases and revenue requirements. Regional rates based on FEI rate classes and structures for each new service area would be implemented. The FEU would combine the gas cost portfolios and develop common commodity and midstream rates while maintaining regional delivery rates for each new service area.

F. *Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream and Delivery Rates*
This final option group, which is the FEU's proposed solution, involves the legal amalgamation of the three FEU entities and consolidation of the FEI, FEVI, FEW and Fort Nelson rate bases and revenue requirements to develop a consolidated COSA model resulting in common commodity, midstream and delivery rates. The Amalgamated Entity would adopt FEI's rate structure.

Table 5-1 below provides a summary of the option groups.

Table 5-1: Summary of Options Groups Considered

Option Group	Legal Amalgamation of Entities?	Consolidation of Costs and Rate Bases?	Common Delivery Rates?	Common Midstream Rates?	Common Commodity Rates?
A) Status Quo	No	No	No	No	No
B) Status Quo with Common Commodity and Midstream Rates	No	No	No	Yes	Yes
C) Amalgamation or Consolidation of One or More Existing Rate Bases with FEI , with One or Two of Existing Rate Bases Remaining as is[112]	Amalgamate two or three legal entities, e.g., FEI and FEW or FEI and FEVI or FEI and FEW and FEVI	• Consolidate the applicable consolidated rate bases and revenue requirements	• Common rates per FEI Rate Structures for the applicable consolidated areas	• Partial • Common Midstream for the consolidated areas	• Partial • Common gas supply portfolio for the consolidated areas
D) Amalgamation of the Three Legal Entities into One Legal Entity; Six Service Areas Maintained; Common Commodity and Delivery Rates with Regional Midstream Rates	Yes	Yes	Yes	No	Yes
E) Amalgamation of the Three Legal Entities into One Legal Entity; New Service Areas Created with Common Commodity and Midstream Rates and Regional Delivery Rates	Yes	Yes	No	Yes	Yes
F) Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream And Delivery Rates	Yes	Yes	Yes	Yes	Yes

[112] See Table 5-4 for a further breakdown of Option Group C

5.4 Step Two – Identification of the Qualitative Objectives

In the second step of the review, the Companies identified a list of objectives against which to consider the option groups. The FEU identified five objectives that address the issues that the FEU are seeking to resolve as described in Section 4 of the Application. The objectives are used to compare option groups and identify the option groups that sufficiently meet the FEU's objectives such that they require a further quantitative analysis.

The evaluation criteria used to assess and evaluate the option groups are summarized in Table 5-2 below.

Table 5-2: Initial Evaluation Objective Descriptions

#	Qualitative Objective	Description
1	Minimize Rate Differences	Does the option minimize rate differences between the different service areas?
2	Address the Revenue Deficiency for FEVI	Does the option address the revenue deficiency for FEVI due to the loss of the government subsidies?
3	Provide Long-term Rate Stability	Does the option provide long term rate stability by mitigating rate impacts resulting from significant expenditures, or the loss of volumes, in the smaller service areas?
4	Mitigate Rate Impact on FEI (Mainland) Customers	Does the option mitigate any rate impacts on FEI (excluding Fort Nelson) customers?
5	Mitigate Rate Impact on Fort Nelson Customers	Does the option mitigate any rate impacts on Fort Nelson customers?

5.5 Step Three - Initial Review against Qualitative Objectives

In the third step, the FEU reviewed the six option groups based on the qualitative objectives described in Table 5-2. The objective of this review was to identify options that required further quantitative consideration.

The FEU reviewed all of the option groups with the following results:

1. Option Groups A and B, and Options C-2 through C-6 were rejected based on the review.
2. Option groups D, E and F and Option C-1 were found to generally meet the qualitative objectives and require a further quantitative review.

The following discussion provides a discussion of the option groups against the qualitative objectives.

5.5.1 REVIEW OF OPTION GROUP A - STATUS QUO

The Status Quo maintains each of the entities and their rate structures, with no corporate amalgamation of the entities.

Option Group A met two objectives as discussed below:

4. **Impact on Mainland Customers** - FEI (Mainland) customers would continue to maintain their existing rates. There would be no change to the current rate structures experienced by customers in each of the service areas.
5. **Impact on Fort Nelson Customers** - Fort Nelson customers would continue to maintain their existing rates. There would be no change to the current rate structures experienced by customers in the Fort Nelson service area.

Option Group A did not meet the remaining three objectives:

1. **Minimize Rate Differences_**– Under the Status Quo, the existing rate disparity between FEU customers served by the separate utilities, including the higher rates for FEVI and FEW customers will continue to exist.
2. **Address the Revenue Deficiency for FEVI** - The Status Quo does not mitigate the loss of the government subsidies for FEVI, which will further contribute to the rate disparity for FEU customers located in FEVI's service territory.
3. **Long Term Rate Stability** – If the Status Quo is maintained FEW and Fort Nelson, and to a lesser extent FEVI, remain vulnerable to the impact of significant capital projects or a significant loss of load.

Option Group A – Status Quo does not meet the FEU's objectives. While it has no rate impact to Mainland or Fort Nelson customers, it does not address any of the objectives 1 through 3. The issues of the potential for increasing rate disparity on FEVI and rate stability on FEVI, FEW and Fort Nelson are not resolved and the different rates for the same service across the service areas remain. The status quo is not a feasible option in the long term and the FEU therefore concluded that it does not merit further consideration.

5.5.2 REVIEW OF OPTION GROUP B - COMMON MIDSTREAM AND COMMODITY RATES ONLY, THREE LEGAL ENTITIES REMAIN IN PLACE

This option group involves maintaining the existing delivery rates in place for each of the Companies with no corporate amalgamation. Postage stamping of the midstream and commodity rates would be achieved with the three gas portfolios consolidated to a single gas supply portfolio and a single set of midstream and commodity rates used across all service areas. The following discussion reviews Option Group B, showing which objectives Option Group B meets and which it does not meet.

Option Group B met objective number 4:

4. **Impact on Mainland Customers –** FEI (Mainland) customers would continue to maintain their existing delivery rates and would only experience a small change to the midstream rate.

Option Group B did not meet the remaining four objectives:

1. **Rate Differences –** While postage stamping the commodity and midstream rates would reduce some of the rate differences across service areas, regional delivery rates would result in the continuation of the most notable rate differences for the same natural gas delivery service to similar types of customers. The bundled residential energy rate for FEVI less the cost of gas, and the delivery rate for FEW would still be significantly higher than the FEI delivery rate; conversely the rate for FEFN would still be significantly lower than the other areas.

2. **Address the Revenue Deficiency for FEVI** – Implementing common midstream and commodity rates would result in only small differences to FEVI revenues and would not address the existing or future revenue deficiency. In addition, moving to common commodity rates could reduce the ability of FEVI to propose and implement different commodity price risk management strategies, which may include the use of financial derivatives, to address its specific cost challenges that would remain if delivery rates were not common. Maintaining separate gas portfolios would give FEVI more flexibility to propose different price risk management strategies or use different tools to manage customers' rates that take into account the unique circumstances of FEVI.

3. **Long Term Rate Stability –** FEVI, FEW and Fort Nelson would remain vulnerable to rate volatility due to delivery rate increases resulting from capital projects

   or a significant loss of load.

5. **Impact on Fort Nelson Customers** – A common midstream rate applied to Fort Nelson would result in approximately a 20% increase to Fort Nelson customers.[113]

As Option Group B does not meet any of the objectives 1 through 3, it does not justify the approximately 20 per cent rate impact on Fort Nelson or even the very limited rate impact on FEI (Mainland) customers that would result. The FEU conclude that Option Group B does not meet the objectives and therefore does not merit further consideration.

5.5.3 REVIEW OF OPTION GROUP C - AMALGAMATION OR CONSOLIDATION OF ONE OR MORE EXISTING RATE BASES WITH FEI, WITH ONE OR TWO OF EXISTING RATE BASES REMAINING AS IS

Option Group C involves a group of options where FEI's Lower Mainland, Inland and Columbia service areas would be combined with one or two of the other service areas by consolidating the rate bases, revenue requirements and gas cost portfolios, with the one or two remaining service areas remaining as is. The delivery, commodity and midstream rates would be postage stamped across the resulting combined areas. Where applicable, the entities would be amalgamated. The six options in this group are outlined in Table 5-3 below for ease of reference.

[113] A 20 percent rate impact is estimated by calculating the midstream rate impact on a typical residential bill of $193.76 ($1.384/GJ x 140 GJ) divided by the proposed January 1, 2013 rates and residential bill in the 2012-2013 FEU RRA of $985.60.

Table 5-3: Description of Option Group C

#	Rate Option	Corporate Amalgamation	Option Description
C-1	Postage Stamp FEI, FEVI and FEW	FEI, FEVI and FEW amalgamate Fort Nelson remain as-is	• FEI, FEVI and FEW amalgamate; common rates implemented; FEFN maintains existing rate structure, rate base and revenue requirements
C-2	Postage Stamp FEI, FEVI and Fort Nelson	FEI and FEVI amalgamate FEW remain as-is	• FEI and FEVI amalgamate; common rates implemented for all of FEI (including Fort Nelson) and FEVI; FEW maintains existing rate structure, rate base and revenue requirements
C-3	Postage Stamp FEI, FEW and Fort Nelson	FEI and FEW amalgamate FEVI remain as-is	• FEI and FEW amalgamate; common rates implemented for all of FEI (including Fort Nelson) and FEW; FEVI maintains existing rate structure, rate base and revenue requirements
C-4	Postage Stamp FEI and FEVI	FEI and FEVI amalgamate FEW and Fort Nelson remain as-is	• FEI and FEVI amalgamate; common rates implemented for FEI (Mainland) and FEVI; FEW and Fort Nelson maintain existing rate structures, rate base and revenue requirements
C-5	Postage Stamp FEI and FEW	FEI and FEW amalgamate FEVI and Fort Nelson remain as-is	• FEI and FEW amalgamate; common rates implemented for FEI (Mainland) and FEW; FEVI and Fort Nelson maintain existing rate structures, rate base and revenue requirements
C-6	Postage Stamp FEI and Fort Nelson	FEI and Fort Nelson consolidated FEVI and FEW remain as-is	• FEI and Fort Nelson consolidate; common rates implemented for all of FEI (including Fort Nelson); FEVI and FEW maintain existing rate structures, rate base and revenue requirements

The following discussion summarizes the review of Option Group C, based on the objectives it meets and those it does not meet.

Options C-1, C-2 and C-4 fully meet one or two of the objectives as discussed below.

2. **Address the Revenue Deficiency for FEVI** – Under Options C-1, C-2 and C-4 FEVI would be consolidated with FEI (Mainland) which would mitigate the impact of the loss of the government subsidies and the revenue deficiency.

5. **Impact on Fort Nelson Customers** – Under Options C-1 and C-4 Fort Nelson would remain separate and not experience any rate impact.

None of the options in this group fully meet any of the six objectives as discussed below.

1. **Rate Differences** – All of the options in this group would result in the continuation of rate differences across the FEU's service areas. Under each option one or two of the entities would continue to have different rates for the same gas delivery services. Option C-1

satisfies this criteria better than the other C options since the rate disadvantage for both FEW and FEVI compared to the vast majority of customers served by FEU would be addressed while Fort Nelson customers would continue to realise lower delivered rates than the rest of FEU's customers.

2. **Address the Revenue Deficiency for FEVI** – Under Options C-3, C-5 and C-6 FEVI would remain as is and therefore these options do not address the impact of the loss of the government subsidies or the revenue deficiency in FEVI.

3. **Long Term Rate Stability –** The separated smaller service areas of FEVI, FEW or Fort Nelson in each option would remain vulnerable due to the impact of significant capital projects or significant loss of load. Options C-1 to C-6 all contemplate combining one or two of the smaller entities with FEI in order to reduce the rate base per customer of the smaller entities. The result is that the combined entity rate base per customer is lower than if the smaller entities remained separate making the combined entity less susceptible to the impact of capital projects or loss of load than the entities would be on their own. However, the separate entity in each Option C-1 through C-6 still remains vulnerable. For example, in Options C-1 through C-3 Fort Nelson, FEW or FEVI, respectively, remain separate and vulnerable. In each of Options C-4 through C-6 two of the smaller entities remain on their own and vulnerable.

4. **Impact on Mainland Customers –** All six of the options considered in this group involve a consolidation with FEI. Since FEI has common rates across the three regions, the rate impacts of combining one or two of the smaller entities with the Mainland is muted. However, each of the options in this group except option C-6 would still drive a rate increase for the Mainland customers.

5. **Impact on Fort Nelson Customers –** There would be no impact to Fort Nelson customers in Option C-1, C-3 and C-4 where Fort Nelson remains as a separate entity for rate making purposes. Of the remaining options, the least impact would be C-5 where common rates are applied across all of FEI's service territory, including Fort Nelson, but the higher rate entities of FEW and FEVI are not combined.

Of the 6 options considered in this group, the FEU concluded that only Option C-1 sufficiently meets the qualitative objectives. Option C-1 fully meets objectives 2 and 5, as FEVI's revenue deficiency would be addressed through consolidation with FEI and FEW and there would be no impact to Fort Nelson. While Option C-1 does not address Fort Nelson's rate stability issues, it also does not impact Fort Nelson's rates. Finally, while consolidating FEVI and FEW with FEI would result in rate impacts to FEI customers, adding Fort Nelson would not materially lessen this impact; therefore Option C-1 addresses the rate disparity issue for the large majority of FEU's customers. The FEU therefore concluded that Option C-1 sufficiently meets the qualitative objectives and proceeded to conduct a quantitative review of the option as discussed in Step 5 below.

5.5.4 REVIEW OF OPTION GROUP D - AMALGAMATION OF THE THREE LEGAL ENTITIES INTO ONE LEGAL ENTITY; SIX SERVICE AREAS MAINTAINED; COMMON COMMODITY AND DELIVERY RATES WITH REGIONAL MIDSTREAM RATES IMPLEMENTED

Under Option Group D, FEI, FEVI and FEW would be amalgamated and the rate bases and revenue requirements would be consolidated. The FEU would combine the entities' gas cost portfolios and develop a common commodity rate while maintaining regional midstream rates across the existing six service areas. The COSA developed would contain a postage stamp cost of service margin and delivery rate structure across the regions, common commodity rates and regional midstream rates associated with the FEI (including FEW), FEVI and Fort Nelson service areas. Since the FEW gas cost portfolio has been already consolidated with FEI's portfolio, this arrangement would continue to remain in place. The regional midstream rates would be developed using the same methodology that is currently employed by FEI for its costing of the Lower Mainland, Inland and Columbia regions' midstream rates whereby the fixed and variable components of costs are streamed according to region.

Option Group D meets objectives 2 and 3 as discussed below.

2. **Address Revenue Deficiency for FEVI** – Under this option, FEVI's costs and customers would be combined with FEI and FEW's costs and customers. This would have the effect of diluting FEVI's revenue deficiency by spreading the deficiency across a larger cost structure and customer base and all things equal would result in lower rates for FEVI.

3. **Long Term Rate Stability** – Costs associated with capital projects and the impact of a significant loss of load would be allocated to all customers; therefore, the impact to the existing smaller service areas would be mitigated.

Option Group D does not meet or fully meet the remaining three objectives as discussed below.

1. **Rate Differences** – Under this option, the rate disadvantage for both FEW and FEVI compared to the vast majority of customers served by FEU, including Fort Nelson, would largely be addressed. However, as each service area would have regional midstream rates, some rate differences would continue to exist across the FEU's service areas.

4. **Impact on Mainland Customers** – The impact on Mainland customers would result in an increase to those customers due to taking on the higher unit costs from the smaller entities.

5. **Impact on Fort Nelson Customers** – The impact on Fort Nelson customers would result in an increase to those customers due to taking on the higher unit costs from the smaller entities, although under this option Fort Nelson would have no midstream rate.

As shown above, Option Group D meets two of the objectives. The three objectives that are not met by this option group, however, require quantitative review to establish the extent to which they impact customers (e.g., the assessment of rate differences is based on minimizing rate differences between service areas). The FEU therefore determined that this option requires a quantitative review of the impact on Mainland and Fort Nelson customers and the rate differences between the service areas so that a conclusion can be drawn. Therefore, the FEU carried this option through to the second round of review.

5.5.5 REVIEW OF OPTION GROUP E – AMALGAMATION OF THE THREE LEGAL ENTITIES INTO ONE LEGAL ENTITY; NEW SERVICE AREAS CREATED WITH COMMON COMMODITY AND MIDSTREAM RATES AND REGIONAL DELIVERY RATES

Under this option, FEI, FEVI and FEW would amalgamate and consolidate the rate bases and revenue requirements of each of the individual entities. The Amalgamated Entity would then redefine its service areas combining the existing service areas into two logical geographic groupings based on their proximity to one another and to address the revenue deficiency faced by FEVI, and the exposure to long term rate impacts to FEVI, Fort Nelson and FEW resulting from capital expenditures, the loss of customers and the loss of volumes. As discussed above, the FEU developed the following redefined service areas upon amalgamation for this option:

- The first region would be a combination of the FEI Lower Mainland Region with FEVI and FEW (the “West Region”).
- The second region would involve the combination of the FEI Inland Region, the FEI Columbia Region and Fort Nelson (the “East Region”).

A regional COSA model would be developed for each of the new service areas, and rates using the current FEI rate structures would be available to all customers. In this option group, all costs (for example, transmission and storage assets, customer administration, etc.), with the exception of the distribution system, are operated and utilized as a whole, and these assets would be allocated across the two new regions. The distribution system for the Amalgamated Entity would be allocated to each of the new service areas based on their specific needs. This would result in common commodity and midstream rates across all service areas and service area specific delivery rates. The following discussion outlines the evaluation of this option group, showing which objectives it meets and does not meet.

There are two objectives that Option Group E meets:

2. **Address Revenue Deficiency for FEVI** – For this option, the FEVI cost structure would be combined with FEI’s Lower Mainland service area and with Whistler. This would have the effect of diluting the FEVI revenue deficiency by spreading the deficiency across a larger cost structure and customer base and, all things equal, would result in lower rates for FEVI.

3. **Long Term Rate Stability** – While two service areas would be in effect and costs associated with capital projects and a significant loss of load would be allocated to each service area, the impact to the existing smaller service areas would be mitigated to a

degree as they would be borne by a larger customer base than the ones in place today for FEVI, Fort Nelson and FEW.

There are three objectives that Option Group E does not meet or fully meet:

1. **Rate Differences** – As two service areas will continue to remain with service area specific delivery rates, rate differences across the Amalgamated Entity's service areas would continue to remain but will be fewer than what exist today. As such, customers will continue to pay a different rate for the same service depending on where they reside.

4. **Impact on Mainland Customers** – The impact to FEI (Mainland) customers would be dependent upon which new service area the customers reside in. For example, under this option group, a customer in the Lower Mainland service area would have a different rate from a customer in the Columbia service area and as such both customers would be impacted by the implementation of this option group.

5. **Impact on Fort Nelson Customers** – Since Fort Nelson costs would be grouped with FEI Inland and Columbia costs there would be an impact on Fort Nelson customers.

As shown in the discussions above, Option Group E satisfies two of five objectives. The three objectives it does not satisfy are rate discrepancies, impact on Mainland customers and impact on Fort Nelson customers. These three criteria require quantitative review to establish the extent to which they impact customers (e.g., the assessment of rate differences is based on minimizing rate differences between service areas). The FEU therefore determined that this option requires a quantitative review of the impact on Mainland and Fort Nelson customers and the rate differences between the two service areas so that a conclusion can be drawn. Therefore, the FEU carried this option through to the second round of review.

5.5.6 REVIEW OF OPTION GROUP F – AMALGAMATION OF THE THREE LEGAL ENTITIES INTO ONE LEGAL ENTITY; ONE SERVICE AREA WITH COMMON COMMODITY, MIDSTREAM AND DELIVERY RATES

In this option group, the three companies - FEI, FEVI and FEW - would amalgamate and consolidate the rate bases and revenue requirements of each of the individual entities (including the service area of Fort Nelson). An amalgamated COSA model would be developed for the Amalgamated Entity and common rates (postage stamped commodity, midstream and delivery rates) across the Amalgamated Entity's entire service area would be established based upon FEI's current rate structures.

The following discussion outlines the review of Option Group F, showing which objectives it meets and does not meet.

There are three objectives that Option Group F meets:

1. **Rate Differences** – Unlike the other option groups, this option group has only one service area and proposes to postage stamp all rates with the result that rate differences

throughout the Amalgamated Entity's service areas will no longer exist. As such, customers will pay the same rate for the same service regardless of where they reside.

2. **Address Revenue Deficiency for FEVI** – Within this option group, FEVI's costs and customers would be combined with FEI's and FEW's costs and customers. This would have the effect of diluting FEVI's revenue deficiency by spreading the deficiency across a larger cost structure and customer base and all things equal would result in lower rates for FEVI.
3. **Long Term Rate Stability –** Costs associated with capital projects and a significant loss of load will be allocated to all customers, therefore, the impact to the existing smaller service areas would be mitigated because of the larger customer base than currently exists for FEVI, Fort Nelson and FEW.

There are two objectives that Option Group F does not meet:

4. **Impact on Mainland Customers** – There would be an impact to Mainland customers under this option group as customers across Mainland's three service areas would be required to absorb the higher cost of service of FEVI and FEW than in place today under FEI's rates.
5. **Impact on Fort Nelson Customers** – There would be an impact to Fort Nelson customers for the same reason as for Mainland customers described above.

As shown above, Option Group F satisfies the three main objectives, but may not satisfy the other two – impact on Mainland customers and impact on Fort Nelson customers. Determining the impact on Mainland and Fort Nelson customers arising from the implementation of this option group requires a quantitative review. The FEU will compare Option F to the other Option Groups carried forward to the quantitative review.

5.5.7 SUMMARY OF QUALITATIVE REVIEW

In summary, the FEU did not carry forward Option Groups A and B and options C-2 to C-6 based on a review of the extent to which they met qualitative objectives. The options that were not carried forward to a consideration of quantitative objectives are listed in Table 5-4 below along with a summary for each of the objectives.

Table 5-4: Summary of Option Groups Not Carried for Quantitative Review

#	Evaluation Criteria	Option Group A Status Quo	Option Group B Status Quo with Common Commodity and Midstream Rates	Options C-2 through C-6 Amalgamation or Consolidation of One or More Existing Rate Bases with FEI , with One or Two of Existing Rate Bases Remaining as is
1	Minimize Rate Differences	**X**	**X**	Partial
2	Address the Revenue Deficiency for FEVI	**X**	**X**	√ (C-1, C-2, C-4) **X** (C-3, C-5, C-6)
3	Provide Long Term Rate Stability	**X**	**X**	Partial
4	Mitigate Impact on Mainland Customers	√	√	**X**
5	Mitigate Impact on Fort Nelson Customers	√	**X**	√ (C-1, C-4) **X** (C-2, C-3, C-5, C-6)

The FEU identified four options or Option Groups that generally met the qualitative objectives, but required a quantitative review to assess the rate impacts and rate discrepancies amongst the service areas. Table 5-5 provides a summary for each of these four options in consideration of the qualitative objectives.

Table 5-5: Summary of Options Requiring Quantitative Review

#	Evaluation Criteria	Option C-1 Amalgamation of FEI (Mainland), FEVI and FEW into One Legal Entity with Common Rates and Fort Nelson Remain as-is	Option Group D Amalgamation of the Three Legal Entities into One Legal Entity; Six Service Areas Maintained; Common Commodity and Delivery Rates with Regional Midstream Rates Implemented	Option Group E Amalgamation of the Three Legal Entities into One Legal Entity; New Service Areas Created with Common Commodity and Midstream Rates and Regional Delivery Rates	Option Group F Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream and Delivery Rates
1	Minimize Rate Differences	**X**[1]	**X**[1]	**X**[1]	√
2	Address the Revenue Deficiency for FEVI	√	√	√	√
3	Long Term Rate Stability	**Partial**	√	√	√
4	Mitigate Impact on Mainland Customers	**X**[1]	**X**[1]	**X**[1]	**X**[1]
5	Mitigate Impact on Fort Nelson Customers	√	**X**[1]	**X**[1]	**X**[1]

[1] Subject to quantitative review.

In the next step of the review, the FEU provide a quantitative summary of the estimated rate impacts and rate discrepancies that would exist for each of these four option groups.

5.6 Step Four – Identification of Quantitative Objectives

In order to further understand the rate implications of each of the option groups requiring quantitative review, the FEU developed COSA models to compare the options. Each of the option COSAs were prepared for comparative purposes only and are discussed by EES Consulting in the Comparative COSA Analysis section of the FEU Natural Gas Cost of Service Review.[114]

Using the COSA models, the FEU assessed each of the four options against three quantitative objectives. Firstly, the Companies evaluated the extent to which an option group would drive rate differences across the service areas and, in particular, the rate impact to FEI and Fort Nelson. Secondly, the Companies compared the per Gigajoule unit cost of service from the COSAs for the various option groups subject to the quantitative review. The unit cost of service is a measure of the cost of service relative to consumption for a class of customers and is useful for gauging the rate discrepancies that would exist under each option. Third, the Companies determined what the option group revenue to cost ratios were in order to assess any rebalancing needed and potential rate impacts.[115]

Table 5-6 below summarizes the quantitative objective descriptions that the FEU used to review the option groups.

Table 5-6: Quantitative Objectives

#	Objective Name	Description
1	Rate Differences	Which option minimizes the negative rate impacts on the service areas – in particular on FEI (Mainland) and Fort Nelson?
2	Unit Cost of Service	What is the difference in rate class unit cost of service per GJ across service areas?
3	Revenue to Cost Ratio	What are the rate class revenue to cost ratios and is rebalancing required?

5.7 Step Five – Quantitative Review of Options

This section discusses the review of each of the four options/option groups against the quantitative objectives identified above.

114 Appendix D-1 EES Cost of Service Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, EES Consulting discusses the comparative COSA analysis on pp.22 to 27.
115 The range of reasonableness is 90 percent to 110 percent and is discussed further in the Rate Design Section 9.7 p. 42.

5.7.1 RATE DIFFERENCE COMPARISONS

In this review, the FEU assessed the extent to which each option would result in rate changes to each of the existing six service areas.

Since each option is a combination of the entities into various regional service areas, the revenues of the service areas were individually adjusted to the same level as the cost of service for that service area.[116] The revenues are adjusted using a three step process:

1. The current revenue for each of the regions is determined;
2. The current regional revenue is compared to the regional cost of service; and
3. The difference between the current revenue and cost of service is determined as a percentage of the current revenue which is the required adjustment for the current regional revenue.

This adjustment of the revenues (and rates) to match total regional cost of service was required for each of the regions in each of the option groups.

In Table 5-8 below, the FEU present the resulting changes to the burner tip rates in each service area that would result from each option.[117]

[116] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, EES Consulting discusses the methodologies used for preparing the comparative COSAs for each of the options on pp.22 to -27.
[117] Appendix I-10: Summary Including Rate Changes Required from Current Rates

Table 5-7: Rate Changes Required from Current Rates for Option C-1, and Option Groups D, E and F

#	Percent Change from Status Quo Rates by (%)	Option C-1 Amalgamation of FEI (Mainland), FEVI and FEW into One Legal Entity with Common Rates and Fort Nelson Remain as-is	Option Group D Amalgamation of the Three Legal Entities into One Legal Entity; Six Service Areas Maintained; Common Commodity and Delivery Rates with Regional Midstream Rates Implemented	Option Group E Amalgamation of the Three Legal Entities into One Legal Entity; New Service Areas Created with Common Commodity and Midstream Rates and Regional Delivery Rates	Option Group F Amalgamation of The Three Legal Entities into One Legal Entity; One Service Area with Common Commodity, Midstream and Delivery Rates
1	FEI Lower Mainland	+5.6%	5.8%	+5.6%	+5.5%
2	FEI Inland	+5.9%	5.9%	+5.5%	+5.9%
3	FEI Columbia	+5.5%	6.2%	+5.1%	+5.4%
4	FEVI	-29.0%	-30.4%	-29.4%	-29.5%
5	FEW	-43.5%	-43.6%	-44.0%	-44.1%
6	Fort Nelson	0.0%	24.8%	+43.1%	+43.5%

5.7.1.1 Conclusion on Rate Difference Comparisons

Based on the results in the table above, the FEU observe that all of the options have similar rate impacts for FEI Lower Mainland, Inland, Columbia, FEVI and FEW service areas. Option C-1 which excludes Fort Nelson from common rates, and Option D which maintains regional midstream rates, have the least impact on Fort Nelson.

5.7.2 UNIT COST OF SERVICE COMPARISONS

In Table 5-8 below the Companies compare the per Gigajoule unit cost of service for each of the four option groups.[118]

[118] Appendices H-8, I-3, I-4, I-5 and J-2, COSA Financial Schedules – Schedule 7 Total Utility Unit Cost of Service

Table 5-8: Comparison of per Gigajoule Unit Cost of Service

FEI					
($/GJ)	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	11.92	8.89	6.26	2.70	8.28
Option D Regional Midstream[119]	11.93	8.83	6.06	2.81	8.25
Option E West Region	11.86	9.00	6.22	2.53	8.27
Option E East Region	11.87	8.83	5.95	2.49	8.12
Option F – Common Rates	11.90	8.88	6.25	2.70	8.28
FEVI					
($/GJ)	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	11.92	8.89	6.26	n/a	n/a
Option D Regional Midstream	12.15	9.32	7.44	n/a	n/a
Option E – Redefine Regions - West Region	11.86	9.00	6.22	n/a	n/a
Option F – Common Rates	11.90	8.88	6.25	n/a	n/a
FEW					
($/GJ)	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	11.92	8.89	6.26	n/a	n/a
Option D Regional Midstream	12.39	9.54	7.62	n/a	n/a
Option E – Redefine Regions - West Region	11.86	9.00	6.22	n/a	n/a
Option F – Common Rates	11.90	8.88	6.25	n/a	n/a
Fort Nelson					
($/GJ)	Rate 1	Rate 2.1	Rate 2.2	Rate 25	
Option C-1 Consolidate Mainland, FEVI and FEW only	8.76	6.51	5.46	1.15	
	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option D Regional Midstream	10.92	8.15	6.50	n/a	n/a
Option E – Redefine Regions - East Region	11.87	8.83	5.95	n/a	n/a
Option F – Common Rates	11.90	8.88	6.25	n/a	n/a

[119] Lower Mainland service area presented.

5.7.2.1 Conclusion on Unit Cost of Service Comparisons

Generally, Option E results in the lower unit cost of service for the existing Columbia and Interior regions of FEI, although Option D also has relatively lower costs than the other options. Options E and F both show lower unit costs of service for FEVI and for FEW. As in the rate change table, Options C-1 and D result in the lowest unit cost of service for Fort Nelson.

5.7.3 REVENUE TO COST RATIO COMPARISONS

The Companies prepared the revenue to cost ratios from the allocated cost of service and rate class revenues for each of the options.[120]

The FEU have summarized the revenue to cost ratios for the four options in Table 5-9 followed by a summary of the results.[121]

[120] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, pp. 22 to 27 EES discusses the comparative COSA analysis.
[121] Appendices H-8, I-3, I-4, I-5 and J-2, COSA Financial Schedules – Schedule 1 Revenue to Cost Ratio at Proposed Rates

Table 5-9: Comparison of Revenue to Cost Ratios

FEI					
	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	93.5%	104.5%	107.7%	110.5%	112.9%
Option D Regional Midstream[122]	92.4%	105.1%	108.2%	111.8%	113.8%
Option E West Region	93.3%	103.0%	107.6%	110.7%	113.1%
Option E East Region	95.4%	106.0%	107.0%	108.9%	115.8%
Option F – Common Rates	93.4%	104.6%	107.9%	110.4%	112.7%
FEVI					
	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	93.5%	104.5%	107.7%	n/a	n/a
Option D Regional Midstream	98.3%	97.4%	105.6%	n/a	n/a
Option E – Redefine Regions - West Region	93.3%	103.0%	107.6%	n/a	n/a
Option F – Common Rates	93.4%	104.6%	107.9%	n/a	n/a
FEW					
	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	93.5%	104.5%	107.7%	n/a	n/a
Option D Regional Midstream	92.1%	98.8%	114.9%	n/a	n/a
Option E – Redefine Regions - West Region	93.3%	103.0%	107.6%	n/a	n/a
Option F – Common Rates	93.4%	104.6%	107.9%	n/a	n/a
Fort Nelson					
	Rate 1	Rate 2.1	Rate 2.2	Rate 25	
Option C-1 Fort Nelson only	80.8%	116.2%	128.9%	126.0%	
	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option D Regional Midstream	90.4%	106.0%	117.2%	n/a	n/a
Option E – Redefine Regions - East Region	95.4%	106.0%	107.0%	n/a	n/a
Option F – Common Rates	93.4%	104.6%	107.9%	n/a	n/a

122 Lower Mainland service area presented.

5.7.3.1 Summary of Revenue to Cost Ratio Comparisons

As summarized in Table 5-9 above, the majority of rates are within the range of reasonableness (considered to be 90 per cent to 110 per cent). For FEI, only Rate Schedule 6 is above the range for all options, and therefore does not result in a marked preference for one option over another. For FEVI, in all options, the revenue to cost ratios are reasonable. The same holds true for FEW, with the exception for Option D for Rate Schedule 3/23. The revenue to cost ratios for Fort Nelson illustrate that rebalancing would be required under the status quo, as Rate Schedules 2.2 and 25 have the highest revenue to cost ratios of all options and across all rate classes. In addition, Rate Schedule 3/23 under Option D has a high revenue to cost ratio for Fort Nelson. Overall, the Companies conclude that when reviewing the revenue to cost ratios, Options E and F are preferable because they eliminate the potential rebalancing requirements to increase residential rates and decrease commercial rates.

5.7.4 CONCLUSION ON QUANTITATIVE REVIEW

Based on reviewing the rate differences, the unit cost of service and the revenue to cost ratios, the FEU conclude that none of the options result in consistently better results across all of the utilities. All of the options reduce rates for FEVI and FEW and have a rate impact on FEI (Mainland) customers. Although Options C-1 and D have the smallest rate impact on Fort Nelson customers, the analysis also shows that rate rebalancing would be required for that service area indicating that some additional rate impacts would result. Further, under Options C-1 and D rate discrepancies with Fort Nelson would continue to exist and under Option C-1 Fort Nelson customers would continue to be vulnerable to long-term rate instability. Only Option F fully meets the objectives of removing rate discrepancies, addressing the revenue deficiency of FEVI and addressing long-term rate stability for FEVI, FEW and Fort Nelson.

On balance, there is no evidence to suggest that any of the other options are superior to Option F. Therefore, based on the benefits of common rates that will accrue to the majority of FEU's customers, the FEU continue to believe that amalgamation and the adoption of common rates is the best solution. Section 6 discusses in further detail the benefits of the FEU's preferred option.

5.8 Summary of Review of the Options

The FEU compared its preferred option to a number of alternatives in consideration of its objectives to:

- Minimize the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW.
- Implement a long-term solution for FEVI customers to the loss of the government subsidies and associated rate impacts;
- Provide long-term rate stability for all customers; and

- Mitigate any significant increases to customers' rates.

After reviewing all of the alternatives considered, the FEU continue to believe that amalgamation and the implementation of common rates are the best solution for the majority of our customers, particularly when considered in combination with the rate mitigation strategies for FEI and Fort Nelson that are discussed in Section 8.

6 THE SELECTED OPTION – COMMON RATES ACHIEVED VIA AMALGAMATION ARE BENEFICIAL IN THE PUBLIC INTEREST

6.1 Introduction

As discussed in section 5, after reviewing other alternatives, the FEU have concluded that amalgamation and the adoption of common rates is the best solution for the majority of our customers. This section provides a review of the benefits and impacts of this solution. For the reasons discussed below, the FEU submit that common rates and amalgamation are beneficial in the public interest.

This section is organized as follows:

- Section 6.2 discusses how common rates will provide the same fair and equitable rates amongst all of the FEU customers.
- Section 6.3 discusses the benefits of mitigating the loss of the government subsidies to FEVI, more economic natural gas rates on Vancouver Island and in Whistler and rate stability in the smaller service areas.
- Section 6.4 discusses the ancillary benefit of simplicity and ease of administration.
- Section 6.5 discusses the ancillary benefit of facilitating consistent access to service offerings.
- Section 6.6 discusses the ancillary benefit of regulatory, reporting and operational efficiencies.
- Section 6.7 discusses the impact of common rates on FEI and FEFN.
- Section 6.8 discusses how common rates fit with government GHG policy.
- Section 6.9 provides a summary of the selected option – common rates.

6.2 Common Rates is the Most Widely Accepted and Equitable Approach

The main principle behind amalgamation and common rates is one of fairness amongst all of FEU's customers. Under common rates, all customers within a rate class would pay the same rate, regardless of location within its service areas.

The FEU understand that the main criticism of common rates is that maintaining regional rates may more accurately reflect regional differences in costs. However, within an Amalgamated Entity common rates are more equitable for all of the FEU's customers. It is difficult to justify continuing rate disparity amongst some customers, when most customers pay the same rates regardless of location. Moreover, the current differences in rates across the FEU are the result of the FEU's growth by acquisition and do not reflect a careful consideration of the equities amongst all of the FEU's customers combined.

In their report in Appendix D-1, EES Consulting compares postage stamp and regional rates and states:[123]

> *Amalgamation of the FEU provides the opportunity for postage stamp pricing throughout the entire service area. The current separate entities/service areas exist because of past ownership differences as well as the use of propane in the case of FortisBC Energy Whistler (FEW). Now that Whistler customers have been converted to natural gas and the utilities have common ownership, there is no need for continuing to operate as separate service areas. Given FEU's proposed amalgamation of the companies FEI, FEVI and FEW, it is necessary to consider the appropriateness and benefits of consolidated rates assuming postage stamp pricing relative to a continuation of the existing regional rate structure.*
>
> *We support the design of rates based on cost of service and both regional rates and consolidated rates can still follow this basic principle. In reality, each customer on the system has a slightly different cost of service based on when they were connected, the location of the customer, the overall energy use, the load profile of the customer, etc. However, it would be impossible to set separate rates for each individual customer. For that reason customers are grouped into rate classes to reflect differences in usage patterns and connection costs. The question then becomes how far to carry the averaging of costs between customers on the basis of location. While there may be regional differences in costs, there are also differences in costs based on each customer's unique location on the system. We do not find it to be equitable to differentiate customer rates on the basis of broad regional differences while not differentiating on the basis of a more specific location or other factors.*

For instance, an argument can be made that regional rates for Vancouver Island better reflect the timing of the introduction of natural gas and the unique costs associated with serving the Island. However, the issue is that these kinds of differences exist throughout the entire natural gas service area of the FEU. As EES Consulting writes: "*In general, customers that were hooked up to the system long ago have lower costs than those hooked up more recently just because of when the facilities were built and the level of depreciation of facilities. Also customers in the more dense urban areas are less costly to serve than customers in more rural locations. Differences also exist because of the distance from the 3rd party transmission pipeline delivery points and because of the geographical terrain.*"[124] Thus, it is more equitable to implement postage stamp rates that remove existing rate differences based on the application of unique factors such as timing, density, location and terrain.

[123] Appendix D-1, EES Consulting, "Natural Gas Cost of Service Review," page 5.
[124] Ibid. page 6.

Postage stamp rates also better reflect the interconnection and sharing of facilities and resources that occur to serve customers. EES Consulting writes:[125]

> *Postage stamp pricing better reflects the fact that utility systems have a high level of interconnection, and facilities are most often shared among large groups of customers. Facilities closer to the customer, like distribution facilities, are more closely tied to local groups of customers, while facilities upstream from the customer, like transmission, are generally used by all customers on the system. When the FEU service areas had separate ownership they were operated as stand-alone entities and needed to rely on their own facilities to deliver gas to customers. Each separate utility had postage stamp rates within their service areas. The acquisition of the different utilities led to operational efficiencies and resulting cost savings. This includes greater integration of existing facilities and installation of new facilities that benefit the entire utility. As the systems become more and more integrated, the application of postage stamp pricing across all regions becomes more appropriate.*

Postage stamp rates are the accepted regulatory approach approved by the Commission for most other utilities in BC and are more widely accepted than regional rates in the utility industry generally. EES Consulting states:[126]

> *"Both regional rates and postage stamp pricing are seen for natural gas rates. Pacific Northern Gas, ATCO Gas and Union Gas maintain regional rates for natural gas. However, postage stamp pricing is the more widely accepted practice in the utility industry and has been adopted as the standard methodology by the Commission across the electric utilities in the Province. It is currently in place for BC Hydro and the FortisBC electric utility, despite previous suggestions by various parties for regional rates. In the 1993 FEI Rate Design proceeding the Commission approved FEI's proposal to provide postage stamp pricing for the Inland and Lower Mainland regions, eliminating the regional differences for delivery charges (although regional differences remained for midstream charges). The FEU currently maintains postage stamp pricing within each of it separate utilities, with Fort Nelson being the one exception of a regional rate within FEI. Postage stamp rates also apply for AltaGas, Centra Gas Manitoba, Heritage Gas, Gaz Metro and SaskEnergy, as well as the majority of gas utilities in the U.S.*
>
> *FortisBC previously consolidated rates for the electric utility when FortisBC acquired Princeton Light & Power in 2007. The acquisition was approved by the Commission in Order G-159-06. While Princeton Light & Power had higher rates for its customers than FortisBC, rates were consolidated and postage-stamped*

[125] Ibid. pages 6-7.
[126] Ibid. pages 5-6.

> *across the combined service area. The full consolidation occurred after several years to allow for a phase-in period until rates were equalized.*
>
> *Postage stamp pricing for FortisBC's electric utility was most recently upheld in Commission Order G-87-07 where outside parties requested a distinct rate for the Big White service area within FortisBC due to large capital projects needed within the region. The Commission found in that case that the area in question was not unique enough to warrant a deviation from postage stamp rates. A similar decision was provided in the case of FEI. In 2004 the District of Chetwynd, which is within the FEI service area, filed a complaint challenging the postage stamp rates and requesting separate rates for the District. The Commission rejected the request in Letter No. L-24-04 and upheld the continuation of postage stamp rates."*

Postage stamp rates are therefore widely accepted as being just and reasonable for customers, despite regional differences that may exist within a utility's service area.

The FEU recognize that the implementation of postage stamp rates will lead to increased rates for FEI customers, especially within the Fort Nelson service area. The FEU discuss later in this section the impact of these rate increases and the FEU's proposed measures to phase-in the impact of common rates. The FEU have consulted with customers and understand their reaction to rate increases as discussed in Section 10 Stakeholder Engagement. The FEU, however, remain convinced that the benefits of postage stamp rates outweigh the disadvantages and that, overall, postage stamp rates is the most equitable approach for all customers.

EES Consulting sums up the attributes of postage stamp rates as follows:[127]

> *The consolidation and postage stamping of rates is recommended for the FEU because it is consistent with standard industry practice and is the accepted regulatory approach approved by the Commission for most other utilities in BC. It recognizes the high level of interconnection of the system and provides benefits to customers by spreading out capital expenditures and providing more stable rates. In particular, we do not see the equity in ignoring locational differences between customers within the large FEI service area while continuing to reflect locational differences between FEI and FEVI, FEW and FEFN customers. The current regional differences in delivery rates are a result of the past ownership structure and do not necessarily reflect the same regional separation that would occur based on operating and cost differences alone. As the ownership structure has changed over the past several years, the current FEU structure no longer requires those rate differences.*

Now that the FEU are under common ownership, FEW has been converted to natural gas and FEVI has paid off the balance in the RDDA and is reaching the end of its financial arrangement

[127] Ibid. page 8.

with the provincial and federal governments, it is the opportune time for the FEU to amalgamate and implement postage stamp rates. The FEU submit that the benefits of implementing postage stamp rates make amalgamation of the FEU beneficial in the public interest.

6.3 Mitigation of the loss of the Government Subsidies to FEVI, More Economic Natural Gas Rates for FEVI and FEW Customers and Rate Stability in Smaller Service Areas

Implementing common rates now will provide a number of benefits. One of the benefits is the opportunity to mitigate the expected rate increases faced by FEVI customers as early as 2016 following the expiration of the province's Royalty Revenues, the repayment of all of the federal/provincial contributions and the return of the RSDA to FEVI's customers as discussed in Section 4. Further, common commodity, midstream and delivery rates will immediately moderate relatively high natural gas rates in Whistler and Vancouver Island. Over the long term, once the rate impacts of amalgamation are accounted for, common rates will bring rate stability to the smaller service areas of FEW, FEVI, Fort Nelson and, to a lesser extent, to the larger service areas of FEI.

As discussed in Section 3, FEVI and FEW pay significantly more than FEI customers for their effective natural gas rates in the absence of common rates. The adoption of common rates for FEI Amalco will result in typical residential, small and large commercial customers in FEVI and in FEW experiencing an average reduction in their total annual bills ranging from 25 per cent to 45 per cent, effective 2014 as discussed in Section 8.4.2. This decrease in annual bills flows from FEVI's and FEW's relatively higher system costs being shared among a much larger customer base including the Mainland. A uniform rate for the larger group of customers served by the FEU will also be more sustainable and stable over time than stand-alone rates for the relatively smaller customer bases in FEVI, FEW and Fort Nelson, which are currently more susceptible to rate volatility in response to changes in throughput and large capital expenditures.

The following sections discuss these benefits in further detail.

6.3.1 MORE ECONOMIC NATURAL GAS RATES FOR FEVI AND FEW CUSTOMERS

A key benefit of the proposal to introduce common rates via amalgamation is to allow FEVI and FEW to access natural gas services at more affordable rates on an equal basis with other customers served by the FEU. For FEVI, common rates will also mitigate the upward pressure on rates expected as a result of the discontinuation of the Royalty Revenues arrangement with the Province at the end of 2011 as well as the additional rate pressures from the repayment of the federal/provincial repayable contributions as discussed in Section 4.

Below we summarize the expected rate challenges facing FEVI and FEW on a stand-alone basis, and how these challenges are addressed by adopting common rates for FEI Amalco.

6.3.1.1 The Challenge Faced by FEVI and FEW on a Stand-Alone Basis

Compared to FEI, both FEW and FEVI have smaller, less-diverse customer bases and a higher rate base per customer. The following table compares FEI's rate base, cost of service and number of customers with FEVI and FEW for the 2013 test year.

Table 6-1: FEVI and FEW Have a Higher Rate Base per Customer[128]

	FEI[129]	FEVI		FEW		FEI Amalco
Rate Base (mid-year 2013) ($000s)	$2,810,535	$815,684	(29.0%)	$41,346	(1.5%)	$3,678,012
2013 Cost of Service ($000s)	$1,285,551	$207,921	(16.2%)	$11,977	(0.9%)	$1,504,835
# of Customers (2013 Average)	859,708	106,360	(12.4%)	2,629	(0.3%)	971,102
Rate Base per Customer	$3,269	$7,669		$15,727		$3,787

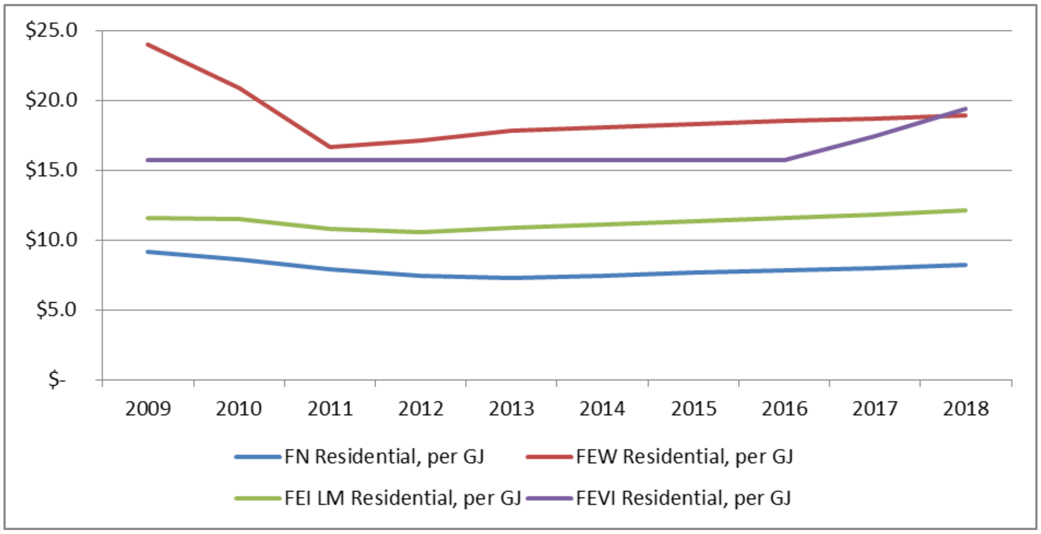
Note: The figures in parentheses represent the relative percentage of each of the three items corresponding to the FEI value.

[128] FEI and FEW amounts as shown in 2012/2013 RRA Sept. 12th Evidentiary Update financial schedules (Exhibit B-21) and FEVI amounts as shown in 2012/2013 RRA Oral Hearing Undertaking 24 (Exhibit B-52); FEI Amalco as provided in Appendix J-1, Schedules 1 and 2

[129] Excludes Fort Nelson.

As Table 6-1 demonstrates, FEVI and FEW as standalone entities have a higher rate base per customer when compared to FEI, which in turn contributes to higher rates.[130] The following figure presents the rate discrepancies within FEI, FEW, FEVI and FEFN service areas for typical residential customers in the absence of amalgamation.

Figure 6-1: Residential Effective Rates across the FEU[131]



Based on the 2013 rates for typical residential customers proposed in the FEU's 2012-203 RRA, customers located in FEVI's and FEW's service areas will be paying 45 percent and 64 percent higher than FEI as shown in Table 6-2.

Table 6-2: FEVI and FEW Customers Pay More for Natural Gas[132]

FEI (LM)	FEI (Inland)	FEI (Columbia)	FEVI	FEW	FEFN
$10.859/GJ	$10.824/GJ	$10.868/GJ	$ 15.725/GJ	$17.790/GJ	$7.280/GJ

The next sections discuss the impact of common rates on FEVI and FEW service areas and how customers in both service areas will benefit from postage stamping through lower rates.

130 A utility with a higher rate base per customer is required to recover its fixed costs from a smaller customer base and on a relatively lower throughput, which translates to higher rates.

131 For purposes of calculating effective rates, typical customer consumption is assumed to be 90GJ. 90GJ reflects the average residential use rate across the FEU. The calculations are based on burner-tip excluding taxes, fees and riders. Please see Appendix J-3 for the rates. The FEU have proposed effective residential rates as of January 1, 2014 using the 2013 test year numbers adjusted for forecast changes in cost of gas. Please note that rates for 2014 through 2018 are indicative only; actual rates will be determined via Revenue Requirement Applications and quarterly gas cost reviews.

132 Ibid. The existing differences across Inland, Columbia and Lower Mainland services areas of FEI are due to different midstream rates.

6.3.1.2 FEVI

The implementation of common rates will harmonize the rates paid by FEVI customers with the rates of all other customers of the FEU in the same rate class.

As discussed earlier in Section 4, FEVI's current RSDA balance only provides a short-term relief from the impact of the loss of the Royalty Revenues. Based on current expectations, the balance in the RSDA will be fully depleted by the end of 2017. FEVI customers already pay more for natural gas on an effective per gigajoule basis compared to their FEI and FEFN counterparts. Once the RSDA balance is depleted and the federal/provincial contributions are repaid, FEVI customers will face further upward pressure on rates.

Figure 6-2 compares the FEVI stand-alone rates both including and excluding the RSDA impact to the proposed amalgamated effective rates.

Figure 6-2: FEVI Residential Rates are Reduced Under Common Rates [133]

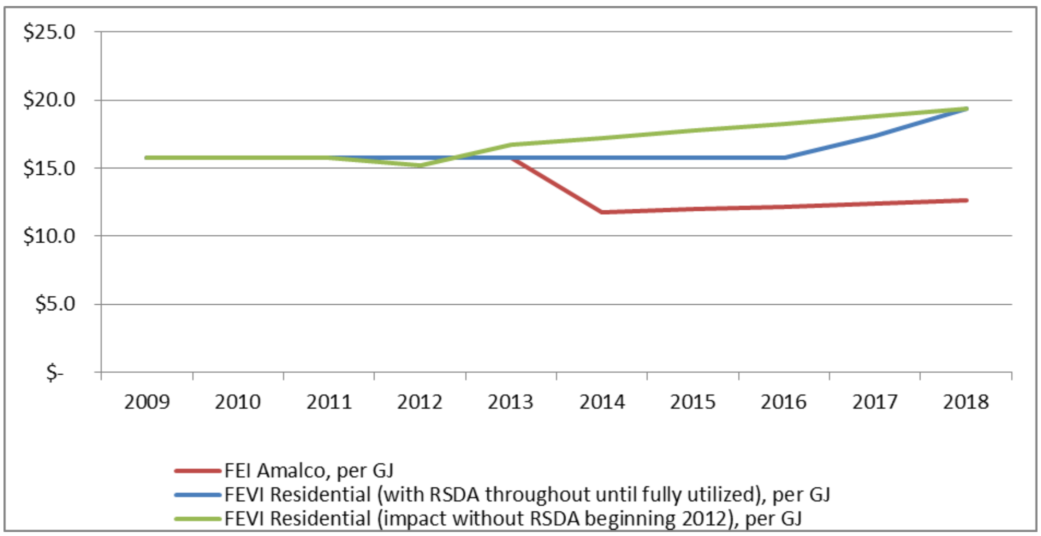


Figure 6-2 shows that, whereas the RSDA provides some temporary relief from the effect of the cessation of government subsidies, the rate disparity between FEVI and FEI remains significant. Postage stamping will both mitigate the rate increases for FEVI and provide a long-term solution for the provision of affordable rates to FEVI's customers.

[133] For purposes of calculating effective rates, typical customer consumption is assumed to be 90GJ. 90GJ reflects the average residential use rate across the FEU. The calculations are based on burner-tip excluding taxes, fees and riders. Please see Appendix J-3 for the rates. The FEU have proposed effective residential rates as of January 1, 2014 using the 2013 test year numbers adjusted for forecast changes in cost of gas. Please note that rates for 2014 through 2018 are indicative only; actual rates will be determined via Revenue Requirement Applications and quarterly gas cost reviews.

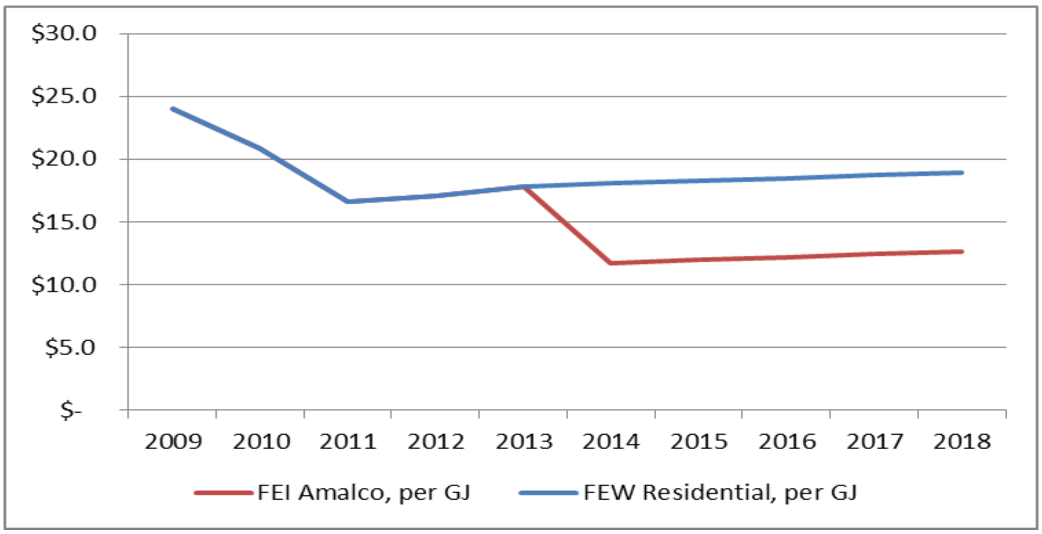
6.3.1.3 FEW

Common rates will also harmonize FEW rates with the rates of all other customers of the FEU in the same rate class.

In the absence of common rates, a typical Whistler residential customer in 2013 is expected to pay an effective rate of $17.790 per GJ for natural gas, compared to $10.859 per GJ for typical Lower Mainland residential customers. This is a difference of approximately 64 percent.[134] FEW customers, upon amalgamation and implementation of common rates, will experience an immediate reduction in natural gas bills. For example, a typical residential FEW customer is expected to see an average annual bill decrease of approximately 37 percent upon amalgamation, equivalent to approximately $616 per year.[135]

Figure 6-3 shows the extent to which effective Whistler burner tip rates under an amalgamation/postage stamping scenario will be reduced compared to the expected bills on a stand-alone basis.

Figure 6-3: FEW Residential Rates Are Reduced Under Common Rates [136]



6.3.1.4 Summary of More Economic Rates for FEVI and FEW

In summary, combining the FEVI and FEW rate bases and customers with FEI, including FEFN, will result in FEVI's and FEW's higher fixed costs being spread over a larger customer base,

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[134] Residential effective rate calculations exclude taxes, other fees, and riders and are based on 90GJ of annual consumption. Please see Appendix J-3, Tabs 1-4 for the summary of the calculations.

[135] Refer to Section 8.4.2 for further information.

[136] Please note that the rate projections provided are high level approximations and may not reflect the forecast cost of service for 2014-2018 or rate proposals that are determined in subsequent revenue requirement applications or regulatory proceedings. The calculations are based on 90GJ of annual consumption.

thereby reducing natural gas rates within the smaller service areas and putting those customers on an equal footing with the majority of the FEU's natural gas customers in the Province. The implementation of common rates provides a long term solution to the higher rates experienced by FEVI and FEW customers. Common rates will provide FEVI and FEW customers with an immediate reduction in their natural gas rates and align them with the rest of the FEU service areas. All else equal, this will help FEVI and FEW retain customers and mitigate the potential for a declining customer base and lower throughput levels which would otherwise lead to further rate increases.

6.3.2 RATE STABILITY AS A BENEFIT TO FEVI, FEW AND FORT NELSON CUSTOMERS

As well as more economic rates in FEW and FEVI, an additional benefit of common rates and amalgamation is rate stability *over time* for natural gas customers of the smaller entities - FEVI, FEW and Fort Nelson. Once the full rate impact of postage stamping has been accounted for, common rates across a combined entity will tend to stabilize rate levels by providing a broader customer base to absorb localized investments in infrastructure for addressing system safety and reliability and/or a localized economic difficulty, without generating spikes in rates.

The 2012-2013 RRA for FEW provides an example of how declines in throughput can impact rates of a small utility. Declining use per customer for large commercial customers combined with reduced customer additions is one of the primary drivers of the revenue deficiencies in FEW for the years 2012-2013.[137] Similarly, as discussed in Section 4.4.4 the Muskwa River Crossing upgrade in Fort Nelson, provides an example of how localized investments can impact small customer bases. The project resulted in an increase to their delivery rate of approximately 13.7 percent.[138] In contrast, if this cost of service was spread out amongst the entire FEI Amalco customer base (approximately 1 million versus 2,500 customers), the estimated delivery rate impact would be an increase of 0.04 percent.

In its Natural Gas Cost of Service Review for the FEU, EES Consulting raises a similar point:

> *"With postage stamp pricing, capital additions are spread out among all customers, making the impact less volatile. Because capital costs are often large and infrequent in nature, if they are directly assigned to a smaller group of customers, the impact will be large at one given time. Postage stamping allows the impacts of capital projects to occur on a more gradual basis."*[139]

In summary, after amalgamation and the adoption of postage stamp rates, the capital costs of FEI, FEVI, FEW and Fort Nelson will be spread across a wider customer base and therefore have a relatively lower impact on rates, particularly for those customers of FEW, Fort Nelson, and to a lesser extent FEVI. This will result in greater rate stability for customers in these areas.

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[137] Appendix C-10, 2012-2013 RRA, Exhibit B-1, Sections 3 (p. 61-62); Section 4 (p. 119-124).

[138] As compared to the 2011 approved Fort Nelson delivery rates, which included a partial year of the Muskwa River Crossing cost of service of approximately $90 thousand, the impact to the 2013 non-amalgamated Fort Nelson delivery rate is an increase of approximately 9% (($260 thousand 2013 COS - $90 thousand 2011 COS in approved rates)/$1,901 thousand 2013 gross margin at existing rates).

[139] Appendix D-1, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, page 7.

6.4 Ancillary Benefit of Simplicity and Ease of Administration

The implementation of common rates will result in rates that are both more easily understood by customers and more easily administered by the Company. This result is consistent with the accepted principle of ratemaking of ease of understandability and administration. As stated by Bonbright in his discussion on the *"Criteria of a Sound Rate Structure,"*[140] the practical attributes of a sound rate structure include:

> *"the related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability and feasibility of application".*[141]

The Commission has previously recognized the importance of the practical attributes associated with common rates. In response to a complaint received from the District of Chetwynd, in Letter No. L-24-04, the Commission upheld postage stamping, stating:

> *"Allocating the total cost of service among the different ratepayers so as to avoid arbitrariness and cross-subsidization is important, but not the only factor to be considered when determining the reasonableness of rates. Other important factors include administrative simplicity, understandability and stability of rates."*

Customers are familiar with common rates because they are in place for the electric utilities in the Province. Both BC Hydro and FBC charge postage stamp rates for electricity within a particular customer class. Based on results from the quantitative study undertaken as part of the stakeholder engagement using web based surveys and a qualitative study using web based bulletin board focus groups, most of the FEU customers are supportive of common-rates in principle, even though seeing the actual rate impact of the common rates application reduces support for the initiative.[142] Anecdotal evidence supports the conclusion that the adoption by FEU of common rates will lead to greater clarity for customers. For instance, a frequent inquiry that call centre agents receive after a quarterly rate change is why a certain group of customers receive a certain amount of decline in their natural gas rates while their rates are remaining the same. This question arises from having different rate structures, regulatory initiatives and rates across different service areas. Common rates can be expected to mitigate this type of confusion for customers.

In addition, during the Common Rates Public Information Sessions (discussed in Section 10), when asked whether they agree with the statement "Common natural gas pricing structures will be simpler and easier to understand", 57% of the customers agreed or strongly agreed that

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[140] James C. Bonbright, Principles of Public Utility Rates (1988), pages 383-384.
[141] Ibid. page 384.
[142] When asked the question whether they support the statement that "the move to common natural gas pricing across the province makes sense for FortisBC customers". 56% of those surveyed somewhat to strongly supported the statement prior to viewing the impacts, while only 16% somewhat to strongly opposed it. Once the approximate impacts on annual bills were shared, the percentage of those participants who originally somewhat to strongly supported the statement, decreased to 41%, and those that opposed or strongly opposed the statement increased to 34%. For more information please see Residential Customer Opinions Common Rates Research Survey Quantitative Report, pg. 36-37.

common rates would be simpler and easier to understand, while 13% of the customers neither agreed or disagreed with the statement.

Figure 6-4 below shows the different rate structures currently in place within the FEU for residential customers and the proposed structure with the common rates.

Figure 6-4: Rate Structure for Residential Customers Before/After Common Rates

	FEI			FEVI	FEW	FEFN
	LM	*Inl*	*Col*			
Basic charge	✓	✓	✓	✓	✓	×
Delivery charge	✓	✓	✓	×	✓	×
Midstream charge	✓	✓	✓	×	×	×
Commodity charge	✓	✓	✓	×	×	×
Energy charge	×	×	×	✓	×	×
Minimum Daily Charge (includes first two GJ/month)	×	×	×	×	×	✓
Consumption based delivery/commodity rates	×	×	×	×	×	✓
Gas cost recovery charge (includes midstream & commodity)	×	×	×	×	✓	×

FEI Amalco	
Basic charge	✓
Delivery charge	✓
Midstream charge	✓
Commodity charge	✓

Common rates facilitate simplified administration, information requirements and billing procedures due to a reduced number of billing determinants (e.g., geographical location), rate categories and classes (e.g., one residential class across six service areas)[143]. This ease of administration is likely to provide minor operational efficiencies. Common rates are therefore beneficial as they are easier to understand and easier to administer compared to regional rates.

6.5 Ancillary Benefit of Facilitating Consistent Access to Service Offerings

Currently, FEI customers have access to certain service offerings that are not available to customers of the other utilities. Although expansion could be achieved through entity specific proposals and approvals, amalgamation and the adoption of common rates will facilitate and accelerate the process of extending Commission-approved service offerings to FEVI, FEW and Fort Nelson customers.

[143] As per the GT&Cs and related rate schedules.

The following table provides a summary of the existing FEU services and illustrates in which service territory they are currently available.

Table 6-3: Amalgamation Facilitates Consistent Service Offerings Across Areas Served by the FEU

	Stand-Alone				Amalgamated
	FEI	FEVI	FEW	FEFN	FEI Amalco
Customer Choice Program	✓	✗	✗	✗	✓
Transportation Service	✓	✓[144]	✗	✗	✓
Compressed Natural Gas Fuelling Service (NGT)[145]	✓	✗	✗	✗	✓
Energy Efficiency and Conservation ("EEC")	✓	✓	RRA[146]	RRA	✓
Biomethane Service	✓	✗	✗	✗	✓
Thermal Energy Services ("TES")	✓	✓[147]	✗	✗	✓

Some of these programs, and the prospects of extending those programs through the FEI Amalco service area, are discussed in detail below.

6.5.1 CUSTOMER CHOICE CAN BE EXTENDED TO FEVI, FEW AND FORT NELSON

The Customer Choice Program is offered by FEI, but is not available in other service areas. The FEU propose to extend the Customer Choice Program to the other service areas after amalgamation and the adoption of FEI's rate structures.

Customer Choice is a BC Government program established to create more competition and choice in natural gas prices. Administered by FEI, the Customer Choice Program offers fixed-rate commodity offerings from independent gas marketers to Rate Schedule 1, 2 and 3[148] customers in the FEI service territory. The business rules of the Customer Choice Program are defined by the Essential Services Model ("ESM"). Under the ESM, gas marketers contract with natural gas customers and deliver commodity to FEI based on the normalized forecast of the gas marketers' customers annual load requirements.

144 Only through special contracts with VIGJV and BC Hydro and through LCS-13 (as described in Section 6.5.2)

145 While there is natural gas vehicle service available on Vancouver Island and in Fort Nelson, in this application the term NGT (previously referred to as NGV) refers to the specific fueling services highlighted in FEI's application for Approval of a Service Agreement for CNG Service and for Approval of GT&Cs for CNG and LNG Service submitted on December 1, 2010, which are limited to FEI.

146 The FEU have applied to expand the EEC programs to FEW and FEFN Service areas as part of the 2012-2013 RRA. EEC programs are not currently available to customers of FEW and FEFN – upon approval of the Companies' current RRA for 2012 and 2013, all programs will be available to all eligible customers across the entire FEU service area. Please note that through BCUC Order No. G-177-11, FEU received interim approval (for the period prior to the Commission's Final Decision on the RRA) an expense schedule totaling $5 million for EEC expenditures to permit the FEU to continue the existing portfolio, with expansion of the interruptible industrial programs to FEVI and the expansion of eligibility for all EEC programs to customers of FEW and Fort Nelson.

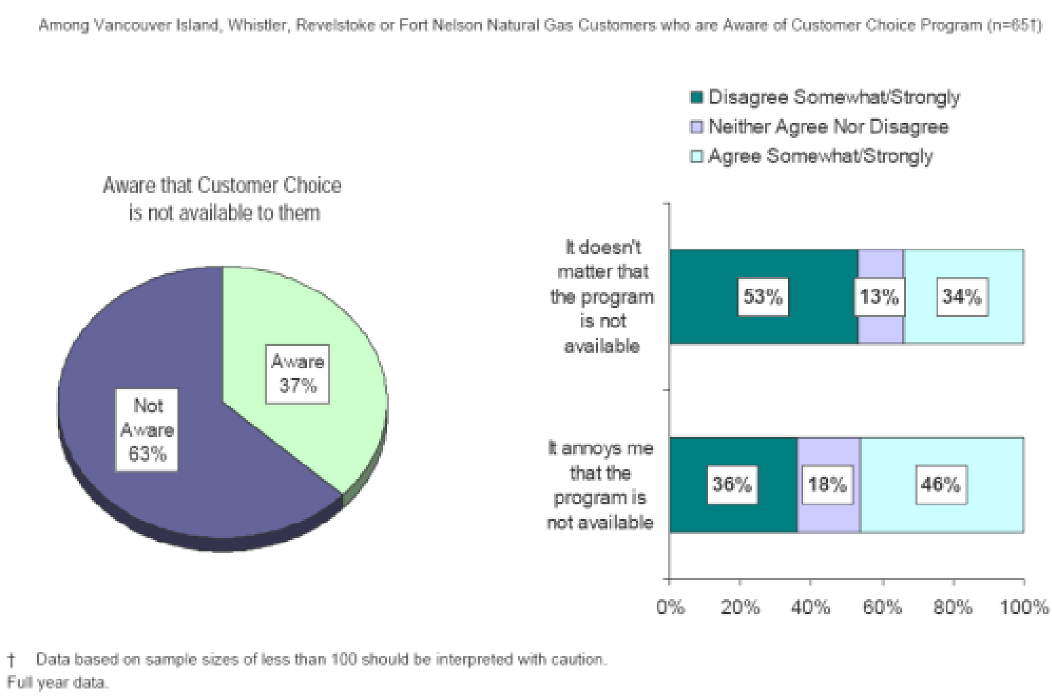
147 For TES, FEI has approval to develop projects within the FEVI service territory.

148 Rate Schedules 1, 2 and 3 are for residential, small commercial and large commercial rate classes, respectively.

FEI implemented the Customer Choice Program for small and large commercial customers in 2004 and expanded the program to residential customers in 2007. As originally set out by the Commission in Order No. G-90-03 and reaffirmed in Order No. C-6-06, all unbundled residential and commercial sales customers are eligible for participation in the Customer Choice Program. Customers located in FEVI, or in FEW, Fort Nelson, and Revelstoke are currently not part of the Customer Choice Program. (Whistler and Revelstoke were propane systems at the time of the decisions and FEVI has a unique rate design that exists as a result of legislation that prevented expansion of Customer Choice). Customers located in Squamish were not eligible until Squamish was amalgamated into the Lower Mainland service area starting in January, 2007. Amalgamation and adoption of common rates provides an opportunity to extend Customer Choice to FEVI, FEW and Fort Nelson (Revelstoke is still a propane system).

In its 2007 customer education campaign, FEI observed that a significant portion of non-eligible customers were aware of the program and dissatisfied that the program was not an option in their service territory:[149]

Figure 6-5: There is Interest in Customer Choice in FEVI and FEW Service Areas[150]



"…In 2008, an additional segment to Figure 10 research was added that asked consumers if they "Would like more information that explains why the program isn't coming to my area." Survey results indicate that 63% of customers who are

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[149] For more information, please refer to the Terasen Gas Inc. "Customer Choice Post Implementation Review Report and Application for Program Enhancements and Additional Customer Education Funding", pages 47, 56, 64.

[150] Ibid. p. 56.

aware that Customer Choice is not available to them want more information that explains why the program is not available in their area"[151]

Expanding the Customer Choice Program to all the FEU regions will provide more customers with the option to purchase fixed-rate commodity offerings from independent gas marketers. The need for extensive customer education and the time required for individual customers to reach business terms with the various natural gas marketers will require a transitional period of a number of months following amalgamation, for the introduction of Customer Choice. The FEU are requesting an implementation date of November 1, 2014 for the expansion of Customer Choice beyond the Lower Mainland, Inland and Columbia service areas.

6.5.2 TRANSPORTATION SERVICE TO BE UNIFORM

Transportation Service is a service whereby the delivery (or transportation) of the natural gas is completed through the distribution system, with the customer purchasing the commodity natural gas directly from the suppliers. There are currently different Transportation Service offerings throughout the FEU, which could be made uniform through amalgamation and the adoption of common rates.

The current Transportation Service offerings throughout the FEU are as follows:

- FEI Rate Schedule 22: Large Volume Transportation - FEI's Rate Schedule 22 services FEI's largest firm and/or interruptible customers. Under this rate schedule, customers are obligated to purchase a minimum of 12,000 GJ per month of delivery costs, regardless of whether or not that was consumed. Annual consumption in this rate schedule though can range from 150,000 GJ to 2,000,000 GJ per year. Rate Schedule 22 interruptible service is priced at a discount from firm service.
- FEI Rate Schedule 23: Large Commercial Transportation Service – FEI's Large Commercial Transportation Service serves FEI customers with a normalized annual consumption at one premise of greater than 2,000 GJs of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- FEI Rate Schedule 25: General Firm Service - FEI General Firm Service rate schedules generally serve larger volume process FEI load customers who use gas for more than space heating. Customers in these Rate Schedules generally have a higher load factor than residential and commercial customers due to their consumption patterns. Customers in these Rate Schedules pay a monthly demand charge, in addition to a monthly basic charge and variable delivery charge which recovers some of the fixed demand related costs related to this customer group. This demand charge reflects the demand they place on the system infrastructure required to meet their peak demand. As such, the better the customer's individual load factor, the lower the demand charge per unit of consumption.

[151] Ibid. page 64.

- FEI Rate Schedule 26: NGV Transportation Service – FEI Rate Schedule 26 provides Transportation Service with an NGT service rate for customers with consumption of greater than 2,000 GJ annually that will only use the gas to fuel service vehicles.
- FEI Rate Schedule 27: General Interruptible Service – FEI Rate Schedule 27 provides FEI customers that are able to have their service curtailed or interrupted during peak periods and during other times when delivery is constrained with non-firm service at discounted rates. Interruptible service is priced at a discount from firm service, where the discount reflects the amount deemed to be sufficient to encourage interruptible customers to remain interruptible while maximising the amount of revenue credited back to firm service customers. Customers in these rate schedules utilize the Company's firm service excess capacity during most of the year, thereby reducing the net cost of service that must be recovered in firm service rates. Typically, large volume process load customers with annual consumption ranging from 10,000 GJ to 150,000 GJ per year, such as manufacturers, greenhouses and service industries that can tolerate interruption in gas usage are served under these rate schedules.
- FEFN Rate Schedule 25: General Firm Transportation – FEFN Rate Schedule 25 is transportation service for FEFN Industrial customers, with a tiered declining variable charge per GJ and a minimum monthly charge. One customer with two separate accounts are currently served under this rate schedule.
- FEVI Rate Schedule LCS-13: Transportation Service – FEVI Rate Schedule LCS-13 is available to customers served off the distribution system with a minimum annual consumption of 6,000 GJ. To date no customers have elected service under this rate schedule[152].

Currently, FEW does not offer transportation service.

Similar to Customer Choice, although expansion could be achieved through entity specific changes, proposals and approvals, amalgamation and the adoption of common rates will facilitate and accelerate the process of providing a uniform Transportation Service across all regions. Subject to approval of this Application, FEI transportation service will be implemented across all the FEU service areas following amalgamation.

6.5.3 NGT FUELING SERVICE EXTENDED TO FEVI, FEW AND FORT NELSON

On February 7, 2012, the Commission approved FEI's General Terms and Conditions 12B for CNG and LNG Service.[153] FEI currently has active service agreements in place with Waste Management of Canada Corporation and Vedder Transport Inc. for the provision of CNG and LNG service. FEVI, FEW and Fort Nelson do not have the equivalent CNG and LNG service offering. Amalgamation of the FEU will facilitate the extension of the CNG and LNG service

[152] FEVI also provides Transportation Service to two transmission customers, BC Hydro and the VIGJV, who are served off the transmission pipeline.
[153] BCUC Order No. G-14-12.

across all of the FEU's service areas, with individual contracts subject to Commission review and approval.

FEI considers NGT to be one of the main opportunities to add throughput to the system to the benefit of customers. Commission Order G-128-11, which considered FEI's CNG and LNG service, states:[154]

> *The Panel finds that if the NGV market can be developed as described in FEI's Application, benefits would accrue to FEI's new NGV customers, its existing ratepayers, and the residents of British Columbia, not to mention FEI itself. These benefits arise from the lower cost of natural gas as a fuel when compared to diesel or gasoline; the increased throughput of natural gas on the FEI system due to the additional consumption of the truck fleet, other things equal, and the reduction of Green House Gas (GHG) emissions from the use of natural gas as compared to diesel or gasoline.*

Under General Terms and Conditions 12B, FEI customers benefit from the increased system throughput resulting from NGT volumes, while the forecast cost of service associated with the fueling stations is recovered from NGT customers through a take-or-pay contract rate.

The benefits of CNG and LNG service can be extended throughout the larger transport market across British Columbia where distribution infrastructure for natural gas already exists. The FEU's proposal to amalgamate and implement common rates using FEI rate structures, including FEI's General Terms and Conditions, will allow the Companies to extend natural gas for the transportation vehicle market across all regions because NGT fuelling service under FEI's approved General Terms and Conditions 12B would be available across the areas served by the FEU.

6.5.4 BIOMETHANE SERVICE

On December 14, 2010, the Commission issued Order No. G-194-10 on FEI's Application for Approval of a Biomethane Service Offering and Supporting Business Model (the "Biomethane Application"). The program was approved on the basis of a two-year pilot period, which requires FEI to provide a comprehensive report on the program at the conclusion of the pilot. The Biomethane Service Offering is another FEI product offering that can be made available to customers in other service areas once the entities have amalgamated. The adoption of common rates will facilitate and accelerate the process of extending the Commission-approved Biomethane Service offering to FEVI, FEW and Fort Nelson customers.

On June 23, 2011, FEI launched the pilot Biomethane product offering for residential customers in the Lower Mainland, Inland and Columbia service areas. Eligible customers have the option of designating 10 percent of their household's natural gas usage as Biomethane, which converts waste from landfill sites, wastewater treatment facilities, and agricultural waste to a usable form

[154] Order No. G-128-11, dated July 21, 2010, Appendix A, Reasons for Decision, page 4.

similar to natural gas. As detailed in the Biomethane Application, a 10 percent blend reduces the GHG emissions of a typical British Columbia home by about half a tonne per year. There are approximately 1,197 residential customers enrolled in the program as of late February 2012. The program also became available to small and large commercial customers on March 1, 2012.

Biomethane is a renewable and carbon neutral energy source. When used in place of natural gas, it results in the reduction of GHG emissions. The production of Biomethane from biomass is a more efficient use of this important renewable resource than generating electricity from it. Currently only available to FEI eligible residential and commercial customers, there are a number of benefits of biogas that would appeal to all BC residents. Conditional on consumer interest after the pilot phase and the availability of sufficient supply, amalgamation and common rates (through unbundling) will facilitate an expansion of eligible customers to include FEVI, FEW and Fort Nelson service areas. This will provide currently ineligible customers with an option to reduce their GHG emissions while continuing to receive natural gas service without adversely affecting throughput.

Additionally, the adoption of common rates and the extension of the established Biomethane regulatory framework to areas other than FEI's service territory would better facilitate access to supply in areas that are not currently in the FEI service territory, and permit that supply to be made available to customers throughout all of the FEU service areas. This expanded supply opportunity and customer market would further assist the Province in meeting its GHG emission targets and would contribute to developing renewable and sustainable energy in British Columbia. As the limitations on the acquisition of Biomethane supply established by the Commission for FEI would continue to apply to FEI Amalco, taking full advantage of this broader access to supply opportunities would likely depend on the Commission lifting the volume limitations as part of the planned Biomethane review following the two-year pilot period.

6.6 Ancillary Benefit of Reporting / Operational Efficiencies

Amalgamation will create financial benefit to our customers through reduced interest expense totalling estimated at $2.0 million.[155] Amalgamation and the adoption of common rate structures for FEI Amalco will also create modest efficiencies, through reduced reporting requirements for regulatory, legal and financial filings. These savings will be sustainable for the long term and are expected to offset the cost of amalgamation over time. The costs and savings related to amalgamation are addressed in more detail below.

The FEU have already realized the operational efficiencies normally associated with an amalgamation via the USP.[156] The significant efficiency gains realized through the USP will remain irrespective of whether amalgamation proceeds. However, there are a few further minor

155 Please refer to Appendix J-1, Schedule 3, Column 7, Lines 11 and 16 which detail the changes in the short and long term interest expense of ($2.2) million and $0.2 million respectively. Please refer to Section 8.1.1.5.1 for calculations. Actual amounts realized will vary by year depending on debt levels and interest rates.

156 An overview of the USP is provided in Section 3.

efficiencies that can be obtained by legally amalgamating the FEU and adopting common rate structures.

An overview of the efficiencies and, where appropriate or feasible, approximate saving estimates, is provided below.

6.6.1 REGULATORY EFFICIENCIES

Consolidation of the separate entities, rate bases and service areas under one unified regulatory structure with a harmonized tariff will reduce the regulatory requirements and streamline quarterly rate filings and other applications, resulting in regulatory efficiencies for all parties involved in the regulatory process, including the BCUC and Interveners. Any immediate direct financial benefit for the customers is difficult to quantify because the regulatory calendar for the Companies is a function of numerous variables, including the number of applications and complexity of the regulatory process[157]. In any event, the initial impact of these efficiency gains would result in a reduction to unpaid overtime of the related employees, which has been a growing concern for the Companies. All else being equal, the regulatory benefits of amalgamation and common rates extend to the BCUC and interveners who participate in the FEU regulatory proceedings.

6.6.2 LEGAL EFFICIENCIES

As discussed in Section 2, the amalgamating companies will become one legal corporation upon amalgamation, continuing to be incorporated within British Columbia and subject to the provisions and regulations of the *BCA*. Thus, FEI Amalco will need to have only one set of company records as opposed to individual records for each entity, as well as lower labour and legal costs to administer each legal corporation. The third- party costs of maintaining corporate records are not significant and thus the savings associated with this efficiency gain are expected to be minimal.[158]

6.6.3 INTEREST SAVINGS

Interest expense savings of approximately $2.0 million are forecast to occur upon amalgamation of the Utilities.[159] While not an operational efficiency gain in itself, interest expense savings serve to reduce the amalgamated cost of service. Savings in interest expense are expected to occur primarily as a result of the application of the FEI short-term debt rate to the FEVI and FEW short-term debt components of approximately $144.2 million. This benefit is discussed

[157] To provide context, a major regulatory proceeding usually cost customers between $300 thousand to $1.5 million dollars in incremental costs, in addition to internal labour devoted to the proceeding, Due to the irregular nature of the regulatory calendar, it is difficult to complete an “all else equal” analysis to determine an exact dollar figure for savings that will be realized.

[158] Currently, annual fees for maintaining the records, preparing the annual resolutions and annual report are about $300 per company. The fee to file annual report is $45 for each company. Post amalgamation annual fee for the amalgamated company would be $300 and the filing fee for the annual report remains at $45.

[159] Please note that the interest savings are subject to change based on relative borrowing costs going forward.

further in Section 8.1 (Amalgamated Cost of Service) and accounted for in the amalgamated cost of service for FEI Amalco (refer to Appendix J-1, Schedule 3, Line 16).

6.6.4 OTHER FINANCIAL EFFICIENCIES

Amalgamating the FEU will result in savings related to auditing and rating agency requirements. The Amalgamated Entity would have to perform one audit as opposed to three separate audits, resulting in lower audit costs. In addition, amalgamation will allow the FEU to reduce rating agency fees as there will be a reduced number of reports required. These cost savings are expected to be approximately $18,000/year for auditing requirements and $100,000/year for rating agency fees.

6.6.5 SUMMARY OF BENEFITS OF AMALGAMATION AND COMMON RATES

The FEU are integrated operationally today and legal amalgamation is the next logical step as a means of facilitating the postage stamping of rates across the FEU. The adoption of common rates will provide equitable rates for all of FEU's customers and provide more economic and stable natural gas rates in FEVI, FEW and FEFN. It also provides several ancillary benefits as described above. In the next section, the FEU address the rate impacts to current customers of FEI and Fort Nelson that would result from the proposed amalgamation and common rate structures.

6.7 Impact of Common Rates on FEI and FEFN Customers

The adoption of common rates will result in FEI and Fort Nelson customers paying higher rates than they would otherwise pay under the current rate structures, to bring all of the FEU's customer rates into alignment. Described below are rate impacts for each of FEI and Fort Nelson customers resulting from the adoption of common rates and the mitigation strategies that the FEU are proposing (further details of the mitigation strategies are provided in section 8).

6.7.1 FEI RATES: INCREASE PARTIALLY MITIGATED BY RSDA FOR THREE YEARS, FOLLOWED BY ONE-TIME INCREASE

The impact of common rates on customers in the FEI Lower Mainland service area will be a one-time increase of 3.3 percent, 2.1 percent and 2.8 percent to total annual bills for residential, small and large commercial customers respectively.[160] However, returning the December 31, 2013 RSDA surplus to FEI customers will help to mitigate the overall impact of amalgamation, as discussed in detail in Section 8, such that the full impact of this one-time increase to the annual bill will only occur only after the RSDA balance is exhausted at the end of a three year period.

FEI already maintains three of its Service Areas – Lower Mainland, Inland and Columbia – under the same commodity and delivery rates. As discussed in section 3, in the early 1990s, the

[160] These impacts are before the application of the RSDA rider and can be found in Appendix J-4, Tab 1.

Commission approved postage stamp delivery charges for the Inland and Lower Mainland residential, commercial and general firm service customers. While holding Columbia region separate, the Commission approved a delivery charge for Columbia that was the same as for Lower Mainland & Inland, and the delivery charges have been the same since then. There are only slight differences in the midstream rates across these three service areas.

Despite the one time rate increase, FEI customers will also benefit from amalgamation and implementation of common rates. As highlighted in FortisBC Energy Utilities 2010 Long Term Resource Plan, FEI is facing a period in which substantial portions (25 to 35%)[161] of its existing infrastructure will be reaching the end of its expected service life within the next decade. While the FEU have been and continue to provide safe, reliable, environmentally responsible and cost effective natural gas service to customers, this wave of aging infrastructure will pose additional challenges for the Mainland and will require additional capital investment, which, in the case of amalgamation would be shared among a larger customer base.

While FEI customers in the Lower Mainland, Inland and Columbia service areas will experience rate increases from the application of postage stamp rates, the FEU are proposing to phase-in the increase through the use of the RSDA. Details on this phase-in approach can be found in Section 8.4.1.3.

6.7.2 FORT NELSON RATE INCREASE

As discussed in Section 3, the natural gas distribution system in the Fort Nelson area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland Natural Gas Co. Ltd. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland Natural Gas and currently operates as a separate service area within FEI. The tariff has been set separately for Fort Nelson from the date the Fort Nelson system was acquired to the present. However, as noted by EES Consulting, this “regional differentiation was not adopted for other customers in the FEI system that might have a higher or lower than average cost of service. It is difficult to justify a continuation of regional rates for this specific area when other areas are not given a similar separation of costs on a regional basis.”[162]

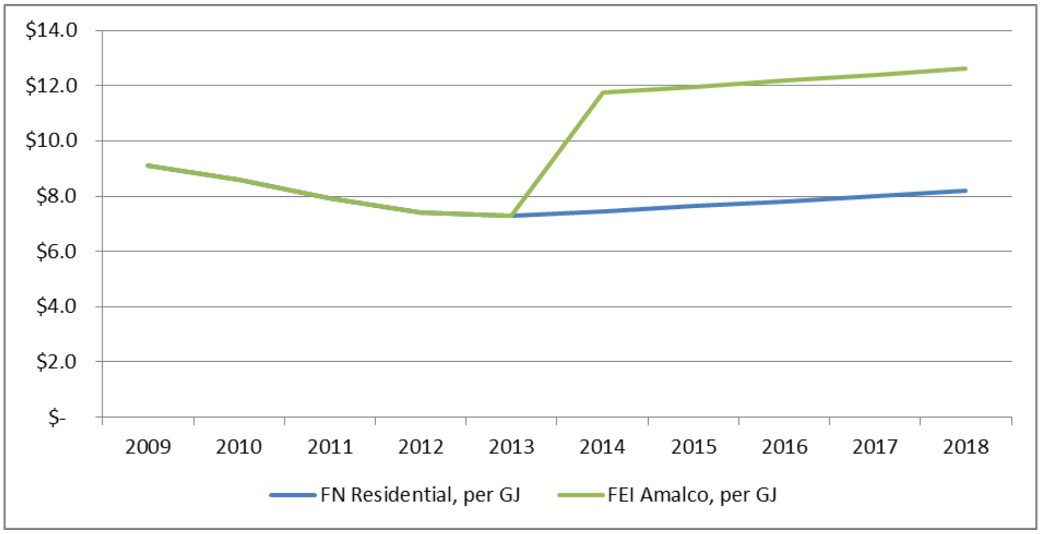
Fort Nelson customers currently pay the lowest rates across the FEU service area. Based on the 2012-2013 RRA filing, in the absence of amalgamation, a typical Fort Nelson residential customer is expected to pay effectively $7.280 per gigajoule for natural gas in 2013 based on the 2013 test year numbers.

As illustrated by Table 6-2 in section 6.3.1.1, if the status quo is maintained, in 2013, effective per gigajoule natural gas rates in Fort Nelson will equal 67 per cent of FEI’s rates, and less than half of FEVI and FEW rates. The impact of common rates on customers in the Fort Nelson service area will be a one-time increase of 55 percent, 28 percent and 23 percent to total annual

[161] FortisBC Energy Utilities (then Terasen Gas Utilities), 2010 Long Term Resource Plan, pages E-10, 153-155.
[162] Appendix D-1, EES Consulting, “Natural Gas Cost of Service Review,” April 2012, page 6.

bills for typical residential, small and large commercial customers, respectively.[163] Figure 6-6 below compares the FEFN stand-alone rates to the proposed amalgamated effective rates for residential customers.

Figure 6-6: FEFN Residential Rates are Increased Under Common Rates [164]



However, the FEU have proposed to phase-in this increase to protect Fort Nelson customers from this significant one-time rate increase. Details on this phase-in approach can be found in Section 8.4.1.1.

The FEU discussed various options with representatives of the Northern Rockies Regional Municipality to address the rate impact associated with the adoption of common rates in the Fort Nelson service area. While the representatives were opposed to any rate increases, they agreed that if the increases were to proceed the FEU should propose to phase-in the total rate increase over a 15 year period with any impact of amalgamation and common rates delayed until year six:

> *"SRM RESOLUTION NO. 98/11*
> *VIGEANT/OSBOURNE that Fortis BC be advised that of the two options suggested for a proposed rate design structure for the Northern Rockies Regional Municipality, Regional Council preferred Option 2 which consists of a 5 year moratorium on fee increases followed by a 10 year accelerated increase."*[165]

Despite the rate increases associated with postage stamping, Fort Nelson customers do derive a benefit. As discussed previously, the Fort Nelson customer base is relatively small

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163 Section 8.4.1
164 For purposes of calculating effective rates, typical customer consumption is assumed to be 90GJ. 90GJ reflects the average residential use rate across the FEU. The calculations are based on burner-tip excluding taxes, fees and riders. Please see Appendix J-3 for the rates. The FEU have proposed effective residential rates as of January 1, 2014 using the 2013 test year numbers.
165 Appendix E-2, Northern Rockies Regional Council Minutes September 20, 2011, page 3.

(approximately 2,500 customers). Any capital project upgrades or reduction in natural gas load result in a large increase in customers' rates when on a stand-alone basis. Under common rates for FEI Amalco, the customer base over which these costs would be spread will be much larger than if these were only applied to the existing Fort Nelson customer base, leading to more stable rates for Fort Nelson customers.

The FEU have consulted with representatives in Fort Nelson and understand that Fort Nelson customers would prefer not to experience rate increases associated with common rates. However, for the reasons described in this Application, postage stamp rates are the most equitable approach for all of the FEU's customers.

6.7.3 SUMMARY

Overall, while there will be increased rates for customers in the FEI and Fort Nelson service areas upon the adoption of common rates, these rate increases are justified by the benefits and result in an overall fair rate structure for all customers. As discussed in Section 8, the FEU propose to mitigate the rate impacts for FEI and FEFN through the RSDA and a phase-in approach respectively.

6.8 How Common Rates Fit with Provincial Energy Policy

This section assesses the impacts of amalgamation and common rates from the perspective of provincial energy policy. Amalgamation and common rates are sought under section 53 and sections 59 to 61 of the UCA, respectively. While none of the UCA sections require the Commission to consider the "British Columbia's Energy Objectives" in the Clean Energy Act, provincial policy generally remains a valid consideration in examining whether amalgamation is in the public interest.

Amalgamation and adoption of common rates is in line with provincial energy policy and the Provincial Government strategy on natural gas. In a recent strategy document,[166] the BC Government addressed natural gas as the world's cleanest-burning fossil fuel and recognizes its ability to *"…significantly lower global GHG emissions by replacing coal-fired power plants and oil-based transportation fuel…"* and that among other things, the Provincial Government would work:

- "to promote natural gas as a transportation fuel" and "introducing a regulation under the Clean Energy Act to advance a proposed natural gas vehicle program"
- "to encourage value-added industries through innovative government programs that reward industry for creating new application of BC's natural gas"
- "to continue to implement emission reduction measures while allowing natural gas sector to maintain its competitive position"

[166] "Natural Gas Strategy: Fueling B.C.'s Economy for the Next Decade and Beyond", 3 February, 2012

- "to establish a BC energy Efficiency Network to promote improved productivity of BC's industrial sector through the efficient use of natural gas"
- "to encourage biomethane opportunities, including offer consumers low-carbon natural gas"

Additionally, the government stressed that the Province will "*amend its existing self-sufficiency policy to better suit today's economic realities, and to foster growth opportunities such as Liquefied Natural Gas (LNG) opportunities.*"[167] Along the same lines, in its BC Green Economy document, the Provincial Government submits that "*BC will continue to lead the world in sustainability producing natural gas through clean technology innovation and the use of renewable energy for processing, while continuing to look for low cost transportation applications and ways to fuel the transition of North America's energy infrastructure*"[168]. These recent developments confirm that natural gas has an important role in the BC Government's future energy strategy and the FEU believe that amalgamation and adoption of common rates is consistent with this strategy.

Natural gas, as the cleanest of the fossil fuels, can be used to help reduce the emissions of pollutants into the atmosphere. Amalgamation and common rates will provide a more consistent basis for FEI Amalco to pursue initiatives that support the use of clean or renewable resources, such as NGT and biogas, further contributing to curbing GHG emission levels in line with the government policy and energy objectives. As described in the natural gas strategy document, BC is home to world leading natural gas vehicle industries, including engine and refuelling technology, and natural gas can help reduce GHG by replacing diesel in heavy duty and medium duty vehicle fleets. All things being equal, NGT initiatives, coupled with more affordable natural gas rates in FEVI and FEW service areas, will make natural gas more attractive as a fuel when compared to diesel and gasoline and will lead to the reduction of GHG emissions. Similarly, expansion of renewable natural gas to the rest of the Province, as facilitated by amalgamation and common rates, would result in the reduction of GHG emissions, further assisting the Province to meet its GHG emission targets.

In the 2012-2013 RRA, Commission staff submitted several information requests about the impact of amalgamation and common rates on British Columbia's energy objectives. The FEU understand the root of these inquiries to be that reducing gas rates on Vancouver Island and in Whistler may make gas service more affordable relative to electricity, thus discouraging customers from switching to a lower GHG fuel source in British Columbia. Overall, the FEU expect the fuel switching between natural gas and electricity to not be sufficiently material one way or the other. Amalgamation and common rates will improve natural gas prices in the FEVI and FEW service areas; however, operational price differential is only one of the many determinants that inform customers' energy choices. Other factors include initial capital cost investment, perceptions about the green attributes of the fuel and space concerns, as discussed

[167] "http://www.newsroom.gov.bc.ca/2012/02/natural-gas-fuelling-new-economic-opportunities.html", last retrieved on April 2, 2012.
[168] "BC's Green Economy: Growing Green Jobs", 14 March, 2012.

in Section 4. Taking all these factors into account, the FEU do not expect any material fuel switching to take place from electricity to natural gas for space heating and hot water as a result of amalgamation and common rates.

More affordable natural gas prices do however have the potential to encourage the remaining customers to switch from higher GHG emitting energy resources, such as furnace oil and propane in the FEVI service area where there still exists reliance on other fossil fuels for space heating and hot water. Using natural gas in place of other fossil fuels, all else equal, will reduce the amount of GHG in BC.

While amalgamation and common rates are in line with provincial energy policy, ultimately, the primary consideration in determining whether amalgamation and common rates are in the public interest should be the benefit to customers in terms of rate fairness across the areas served by the FEU and the other benefits of common rates as discussed in this section.

6.9 Summary of the Selected Option: Common Rates

FEI already has approximately 850,000 customers on the same delivery and commodity rates across the Mainland of BC. Similarly, FEVI, FEW and Fort Nelson customers enjoy common rates within their respective service areas. It is appropriate to extend the principle of common rates across all service areas.

Common rates, through amalgamation of the FEU, provide important benefits that make them beneficial in the public interest. In addition to removing the existing rate disparity across the FEU's service areas, common rates will provide a permanent solution to the long-standing issues on FEVI. While FEVI has been supported over the past decades by the provincial and federal government under the complex VINGPA and associated agreements and regulations, those mechanisms are coming to an end. Amalgamation and common rates will improve the basis on which an economic natural gas distribution utility can operate in FEVI's service area. Common rates will similarly bring more economic rates to FEW, which currently experiences much higher natural gas rates than elsewhere in the Province served by the FEU. Another important benefit is the rate stability that will be brought to FEW, FEFN and to a lesser extent, FEVI, service areas which have smaller and less diverse customer bases than FEI. Ancillary benefits of amalgamation and common rates include simplicity and ease of administration, consistent and expanded service offerings, and reporting and operational efficiencies.

While FEI and Fort Nelson will experience rate increases, overall the rates will be fair and equitable for all customers. Amalgamation and the adoption of common rates represent a logical step in the evolution of the Companies. For the reasons described in this section, the FEU submit that amalgamation of the FEU is beneficial in the public interest.

7 IMPLEMENTATION OF COMMON RATES

7.1 Introduction

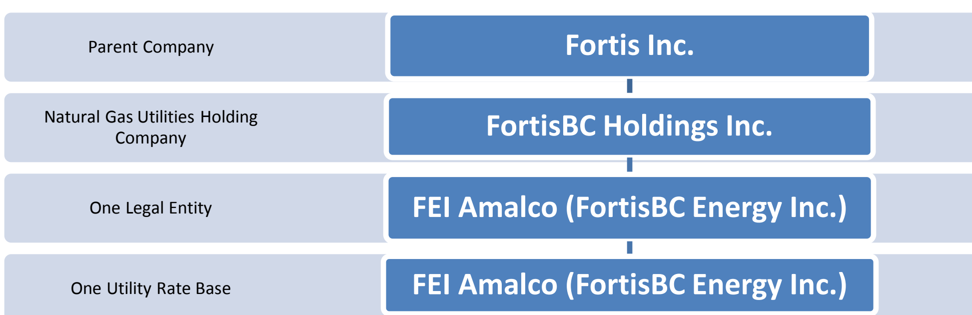
In this section, the FEU discuss the legal requirements to amalgamate, the amalgamation with Terasen Gas Holdings Inc. and the effects of amalgamation and postage stamping on its operations, including the impact on terms and conditions, existing special contracts and tariff supplements as well as system extension and connection policies and the gas procurement portfolio.

7.2 Legal Requirements to Amalgamate

This Application is proposing an amalgamation of the FEU for the purpose of achieving common rates. In addition, the Application is proposing the amalgamation of Terasen Gas Holdings Inc. for the purposes of simplifying the corporate structure.

In order to understand the rate proposals, it is important to understand that amalgamation is a legally different concept from one of a company purchasing the shares or assets of the FEU. The FEU and Terasen Gas Holdings Inc. have a common shareholder already: FortisBC Holdings Ltd. While Terasen Gas Holdings Inc. owns approximately 19% of the shares of FEI, Terasen Gas Holdings Inc. is in turn 100% owned by FortisBC Holdings Ltd. Upon amalgamation of the three gas utilities and Terasen Gas Holdings Inc., the four companies will "continue as one company"[169] (one legal entity) with the same shareholder. No assets will be transferred. No shares will change hands. The three FEU companies will, in effect, become one company. That new amalgamated entity will keep the name FortisBC Energy Inc., and FEVI and FEW will no longer exist as separate entities. The proposed structure after amalgamation is shown below in Figure 7.1.

Figure 7.1: Corporate Structure after Amalgamation



[169] Business Corporations Act, S.B.C. 2002, c. 57, section 269.

The following sections discuss the legal requirements to amalgamate under the Utilities Commission Act, the Business Corporations Act, and FEI and FEVI's trust indentures and credit agreements as well as the legal effect of amalgamation on the interests, rights, and obligations of FEI, FEVI, and FEW.

7.2.1 REQUIREMENTS UNDER THE UTILITIES COMMISSION ACT

Section 53 of the UCA outlines the process to be followed in order for the FEU to receive approval for amalgamation. There are four steps involved:

- First, as stated in section 53(3), an application to the Commission must be made for the consent of the Lieutenant Governor in Council (the "LGIC");
- Second, under section 53(4) of the Act, the Commission must inquire into the application for amalgamation and consider whether the amalgamation would be beneficial in the public interest;
- Third, if the Commission determines that the amalgamation would be beneficial in the public interest, section 53(5) of the Act requires the Commission to submit a report and its findings to the LGIC; and
- Finally, the LGIC considers the report and findings of the Commission in determining whether to issue an order consenting to the amalgamation.

The FEU are therefore applying to the Commission in accordance with section 53(3) of the UCA with the aim of obtaining the consent of the LGIC to the amalgamation of the FEU, effective January 1, 2014.

7.2.2 REQUIREMENTS UNDER THE BUSINESS CORPORATIONS ACT

The FEU contemplate an amalgamation under section 270 of the BCA, which essentially allows for the amalgamation of FEW, Terasen Gas Holdings Inc. and FEI, and FEVI and FEI through amalgamation agreements adopted by a shareholder resolution of each amalgamating entity. FEI Amalco, the amalgamated corporation formed, will retain the name FortisBC Energy Inc.

The agreements, resolutions, and other corporate documents necessary for the completion of the applied-for amalgamation under the BCA, if prepared in advance of the issuance of the LGIC finding that the amalgamation would be beneficial in the public interest, can be implemented in short order.

7.2.3 REQUIREMENTS OF TRUST INDENTURES AND CREDIT AGREEMENTS

Both FEI and FEVI have requirements pertaining to amalgamation in their respective trust indentures and credit agreements that will need to be complied with. These requirements are as follows.

- Trust Indentures - FEI has two Trust Indentures and FEVI has one Trust Indenture.

- FEI's Trust Indentures permit amalgamation of FEI with one or more other companies if certain terms and conditions are complied with. For instance, FEI's Trust Indentures contain a "Successor Company" provision which essentially requires that FEI not enter into any transaction whereby all or substantially all of its undertaking would become the property of another company – called the successor company – unless, among other things, the successor company executes an indenture that is satisfactory to the Trustee to evidence the assumption by the successor company of the due and punctual payment of all the debentures under the trust indenture and the agreement of the successor company to observe and perform all of the obligations of the Company under the trust indenture. Additionally, the transaction shall, to the satisfaction of the Trustee and in the opinion of counsel, be upon such terms as substantially to preserve and not to impair any of the rights and powers of the Trustee or the holders of the debentures under the trust indenture upon such terms as are in no way prejudicial to the holders.

  FEVI's Trust Indenture permits FEVI to amalgamate with FEI (or its successor). The Trust Indenture requires the amalgamated corporation to execute a debenture supplement, which, among other things, needs to include a provision that the amalgamated company shall be obligated to pay all principal, interest, and other amounts payable in respect of FEVI debentures.

- Credit Agreements - The credit agreements of both FEI and FEVI permit each respective entity to amalgamate provided certain conditions are met. Specifically, FEVI's credit agreement was amended to allow for amalgamation of FEVI with FEI or a successor.

FEI believes that the proposed amalgamation can be accomplished within the requirements of the existing FEI and FEVI Trust Indentures as described above, and within the requirements of the FEI and FEVI credit agreements described above, and otherwise in compliance with the FEI and FEVI Trust Indentures.

7.2.4 LEGAL EFFECT OF AMALGAMATION

Some of the specific consequences of the amalgamation include the following:

- The assets currently owned by FEI, FEVI, FEW and Terasen Gas Holdings Inc. will be owned by FEI Amalco. Upon amalgamation, there will not be a disposal of property since FEI Amalco will remain the owner of the assets in areas served by the FEU.
- The interests, rights, and obligations of FEI, FEVI, FEW and Terasen Gas Holdings Inc. will become the interests, rights, and obligations of FEI Amalco. Thus, upon the amalgamation, the obligations, rights and assets of the amalgamating companies will, in effect, be merged. Third-party suppliers, or other third parties linked to the FEU by contract, will notice no practical change vis-á-vis their contracts.
- As a consequence of the interests, rights, and obligations of FEI, FEVI, FEW and Terasen Gas Holdings Inc. becoming the interests, rights and obligations of FEI Amalco, the contracts among the amalgamating companies are cancelled. Simply put, a company cannot enter into legally binding contracts with itself. There are a number of

agreements among FEI, FEVI and FEW that will be effectively cancelled by amalgamation. Examples of such contracts include the Transportation Service Agreement between FEI and FEVI and the Shared Services Agreements. The shares of FEI that are currently held by Terasen Gas Holdings Inc. would be cancelled and FortisBC Holdings Inc. would become the sole, direct shareholder of FEI Amalco.

- In the absence of an order to the contrary, the rate structures of each amalgamating utility would become approved rates for FEI Amalco. With respect to the rate structures, the scenario where the rate structures of each amalgamating entity would become approved rates for the entire entity is unworkable. The FEU are proposing to harmonize rates, which is the primary objective of amalgamation. There are orders sought that request approval of these harmonized rates for FEI Amalco.
- FEI Amalco would, in theory, become subject to the VINGPA Special Direction that currently applies only to FEVI. However, the contemporaneous adoption of common rates and in particular, the fact that a rate for Squamish Gas is no longer required, brings the Special Direction to an end based on the terms of the Special Direction.[170] The FEU would not proceed with amalgamation in the absence of approved common rates and, as such, this issue of the impact of the Special Direction becomes moot.

The consequences listed above have been taken into account by the FEU in proposing common rates and are reflected in the orders sought for this application.

7.3 Amalgamation with Terasen Gas Holdings Inc.

As part of the amalgamation process, the FEU are proposing to take the opportunity to simplify the corporate ownership structure of the Amalgamated Entity by amalgamating Terasen Gas Holdings Inc. as well.

The sole asset of Terasen Gas Holdings Inc. is its approximate 19% interest in FEI. The issuance of shares to Terasen Gas Holdings Inc. was approved by the Commission in Order G-95-00, dated October 5, 2000, as part of the financing arrangements for the Southern Crossing Pipeline Project. As recorded in the recitals of Commission Order G-95-00, the purpose of the arrangements was “to optimize certain financial aspects of the SCP Project while ensuring that customers and their rates were not adversely affected”. The financing structure including Terasen Gas Holdings Inc. was unwound in late 2005. Since that time, Terasen Gas Holdings Inc. has been inactive other than being a holding company in respect of its shares of FEI. The existence of Terasen Gas Holdings Inc. no longer provides any benefits to FEI, ratepayers or its shareholder. Terasen Gas Holdings Inc. is not a public utility and has no employees.

[170] 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. The remaining condition is the Squamish Gas TSA, which would terminate if the FEU were to amalgamate.

The amalgamation with Terasen Gas Holdings Inc. would have no impact on the Amalgamated Entity or its ratepayers. The sole effect of amalgamation with Terasen Gas Holding Inc. would be that Terasen Gas Holdings Inc. would cease to exist and its shares of FEI would be canceled in accordance with the BCA.

In summary, if the amalgamation of the FEU is approved, it is convenient and efficient to also amalgamate Terasen Gas Holdings Inc. in order to simplify the ownership structure of the Amalgamated Entity. The FEU therefore submit that it is beneficial in the public interest to do so. If for any reason the Commission holds that amalgamation with Terasen Gas Holdings Inc. is not beneficial in the public interest, the amalgamation of the FEU could proceed without it and Terasen Gas Holdings Inc. could continue to exist and remain a shareholder of FEI Amalco.

7.4 Operational Effects of Amalgamation

7.4.1 INTRODUCTION

The following section describes the effects of amalgamation and common rates on the FEU's operations and focuses on the impacts on terms and conditions, existing Tariff Supplements and special contracts, system extension and customer connection policies, gas supply and other significant operational matters. The effect on financing costs is discussed in section 8.

7.4.2 HARMONIZATION OF TERMS AND CONDITIONS OF SERVICE

This section describes how, upon amalgamation, the FEU propose to harmonize the terms and conditions of service currently in place in the various utilities. Particularly, the FEU propose that:

- FEI's GT&Cs be adopted with minor modifications;
- Approved Special Contracts and Tariff Supplements remain in effect; and
- The MX Test applicable to both FEI and FEVI continues to apply to FEI Amalco.

7.4.2.1 FEI's General Terms & Conditions to be Adopted with Minor Modifications

Upon amalgamation, the FEU propose that the existing Terms & Conditions for each of the companies be replaced by a common set of GT&Cs for FEI Amalco. The common set of GT&Cs, similar to those of the current FEI service area, will harmonize tariff, rate design principles and rate classifications across all areas served by FEI Amalco. The adoption of FEI's current rate structures makes sense as the GT&Cs for FEVI, FEW and FEFN are already structured after FEI and most of the FEU's customers are already subject to FEI's rate structures.

If amalgamation is approved, the areas to be served by FEI Amalco will include the locations and surrounding areas listed in the proposed GT&Cs. Although a common rate will be applicable to all locations to be served by FEI Amalco, due to the proposal to use rate riders to phase-in the impacts of amalgamation for FEI (Mainland) and Fort Nelson as discussed in Section 8, the Companies will group locations into three areas: Mainland area; Fort Nelson area; and, Vancouver Island and Whistler area.

To reflect the harmonized tariff, rate design principles and rate classifications across areas served by FEI Amalco and to be mindful of the necessary rate riders, the Company proposes to make amendments to FEI's effective GT&Cs. The most notable amendments include, but are not limited to:

1. Removing the use of the defined term "Service Area" used to distinguish the previously distinct Service Areas (or Divisions) of Inland, Columbia and Lower Mainland for FEI. This is replaced with the phrase "Areas Served by FortisBC Energy" where appropriate.
2. Using the new term "Transportation Areas" in Rate Schedules 14A, 22 and 27 to maintain the necessary locational criteria for Shippers when applying to group nomination and balancing.
3. Redefining the term "Transporter" to reflect the unified service area of the Amalgamated Entity.
4. Retaining the definition of "Inland Service Area", "Columbia Service Area" and "Lower Mainland Service Area" as they were previously identified and included in FortisBC Energy Inc. General Terms and Conditions (Order G-28-11, Effective March 1, 2011) for only Rate Schedules 22A, 22B, 23, 25, 26 and 40 to refer to specific areas or locations. These definitions are required as these rate schedules are either grandfathered and confined to one of these former service areas, or are required to be maintained for group nomination and balancing, or have sections that refer to conditions of service within a grandfathered or transportation rate schedule.
5. Currently, FEVI's Standard Terms and Conditions contain provisions relating to a transmission transportation service offering. After amalgamation, these services are required to be maintained to facilitate the continued provision of service to FEVI's two significant transmission transportation customers, the Vancouver Island Gas Joint Venture and BC Hydro.171 An addition to the proposed GT&Cs is thus necessary for FEI Amalco to continue to provide the transmission transportation service offering upon amalgamation.

The FEU have also made some other minor housekeeping changes to the tariffs and rate schedules, which include updating of the name and formatting for the purposes of consistency, clarity and ease of referencing.

A copy of the proposed set of rate schedules and GT&Cs is included in Appendices B-1 and B-2, respectively, for Commission approval. For comparison, a black-lined version of the proposed set of GT&Cs, together with the FortisBC Energy Inc. GT&Cs as set out by Order No.

[171] The agreements and associated GT&Cs, including the Transmission Transportation Service Tariff, for BC Hydro and VIGJV will be filed once the agreements are signed.

G-28-11, effective March 1, 2011, is also included in Appendix B-3 to illustrate all amendments made.

7.4.2.2 Approved Special Contracts and Tariff Supplements to Remain in Place

As proposed, special contracts and tariff supplements for service arrangements that have been approved by the Commission and are in effect as of the implementation date of amalgamation and postage stamping will continue in effect in accordance with the terms of those arrangements. The FEI Amalco will be called FortisBC Energy Inc. and, as such, special contracts with FEI need not be amended to reflect a new name. Amended Tariff Supplements issued by FEVI, FEW and Fort Nelson, changed only to reflect the FEI Amalco name, will be required to be updated and submitted for endorsement to the Commission. As amending the Tariff Supplements requires both the Company and the customer to sign the amended document, the FEU believe it is more efficient to wait until the LGIC consents to the amalgamation before beginning this work.

The rates for special contract and large industrial customers, including the FEVI large industrials (VIGJV and BC Hydro), Lower Mainland region Rate Schedule 22 customers, Inland region Rate Schedule 22A and bypass contract customers, and Columbia region Rate Schedule 22B customers will also be unaffected by the amalgamation. The large industrial and special contract customers have specific rate structures and operating conditions appropriate for their regions in the Province and history of service. The FEU believe that these specific rates, rate structures and tariffs are still appropriate for the Company's large industrial customers. Treatment of special contract and large industrial customers is discussed in Section 9.

7.4.2.3 Continuance of FEI/FEVI's Main Extension Test

In their 2007 System Extension and Customer Connection Policies Review Application, FEI (including Fort Nelson) and FEVI sought and received approval to establish the main extension test, applicable to those entities. The FEU are requesting approval for:

- The continuation and application of the FEI and FEVI approved MX Test (with the same established PI thresholds) to the FEI Amalco, and the discontinuance of the MX Test applied currently in Whistler; and
- The use of amalgamated inputs into the MX Test.

In support of these requests, the FEU have analysed the FEI, FEVI and FEW main extensions from 2008-2010 to determine the impact of using amalgamated inputs on historical MX Tests. As discussed below, the FEU's customers would have experienced no major changes in MX Test results flowing from amalgamation, suggesting that the Companies' proposal is consistent, reasonable and will closely preserve the status quo.

MX Test Background

As stated in the Decision accompanying Order No. G-152-07, in which the Commission approved FEI and FEVI's current extension and connection policy, "the primary purpose of extension and connection policies is to promote fair and equitable treatment of customers and, more specifically, to ensure that customers in existence at the beginning of the year are not adversely affected by the addition of a full year's cohort of customers."

All applications to extend the gas distribution system to Rate Schedule 3 and larger customers and for any customers connecting to a service header including vertical subdivisions are subject to the Commission approved MX Test. The MX Test develops a Profitability Index ("PI") which is the ratio of the discounted present value of all forecast net cash inflows over twenty years divided by the discounted present value of the capital costs of attaching customers in the first five years of the main extension. Arriving at the appropriate PI threshold is a balancing exercise. The higher the PI threshold required of new extensions, the more protection is conferred upon existing customers by requiring a higher forecast of profitability of the new extensions. However, a higher PI threshold also makes it more difficult to add customers and bring the benefits of new load to the system.

Under Order No. G-152-07, the Commission approved for both FEI and FEVI that if an individual PI is 0.8 or greater, the system extension can proceed without the need for a customer contribution. If the PI is less than 0.8, a customer contribution in aid of construction ("CIAC") would be required to make up the shortfall to bring the PI up to the 0.8 threshold, before the system extension can be built. In the same Order, the Commission also approved an aggregate PI of 1.1 as a threshold for the portfolio of main extensions completed on an annual basis.

FEW uses the same MX formula as FEI and FEVI but has an individual MX Test PI threshold of 1.0 and, unlike FEI, FEVI and FEFN, it does not have an aggregate PI threshold, as per Commission Order No. G-35-09.

The Companies currently use the same discounted cash flow test to evaluate main extensions; however, the values for the individual inputs for the tests vary between each utility. For example, delivery margins would be different for FEVI and FEI based on their respective Commission-approved rates. While there are many components factored into the calculation of this ratio, the following PI formula provides a summary of the major components:

> PI = Net Present Value of Net Cash Inflows (Delivery Margin + Connection Fees – O&M - System Improvement Charge – Property Tax – Income Tax)/Net Present Value of Capital Costs (Mains, Services, Meter Costs)

Adoption of FEI/FEVI PI Thresholds Upon Amalgamation

Upon amalgamation and the adoption of common rates it is appropriate to continue with the PI methodology as approved by the Commission under Order No. G-152-07 for FEI and FEVI whereby an individual PI threshold of 0.8 and an aggregate PI of 1.1 are to be used. This means that FEW will be adopting the FEI and FEVI PI thresholds to bring all service areas across the areas served by the FEU into alignment. They will also continue to apply to Fort Nelson as they are today.

Use of PI Inputs Reflecting FEI Amalco

The FEU propose that FEI Amalco use one set of PI formula inputs reflecting the amalgamated entity as a whole. This section begins by summarizing the changes to the PI formula inputs resulting from amalgamation, followed by an analysis of the impact of implementing these changes on historical FEI, FEVI and FEW main extensions.

Six inputs into the PI formula will be impacted by amalgamation:

- System improvement (“SI”);
- Discount rate;
- O&M;
- Property tax;
- Variable margin; and
- Fixed margin.

For example, FEI, FEVI, and FEW have historically been using separate O&M values specific to each individual utility when running MX tests. In comparison, amalgamation will result in a single O&M value for all. A summary of the changes to the inputs into the PI calculation resulting from amalgamation is provided in the table below for illustrative purposes using the 2013 test year numbers.

Table 7.1: High Level Overview of Changes to MX Test Inputs Resulting from Amalgamation[172]

Utility	SI	Discount Rate	O&M[173]	Property Tax	Variable Margin	Fixed Margin
2013 FEI	$ 0.160	6.8%	$ 89.47	2.01%	$ 3.880	$ 142.08
2013 FEVI	$ 0.151	6.5%	$ 72.83	1.90%	$ 7.376	$ 126.00
2013 FEW	$ 0.160	6.2%	$ 65.00	2.01%	$ 11.686	$ 90.00
2013 FEI AMALCO	$ 0.159	6.7%	$ 87.57	1.99%	$[174] 4.361	$ 141.99

[172] Components of these inputs are derived from the financial schedules of the 2012-2013 RRA and are subject to change based on the final approved 2013 standalone and amalgamated schedules.
[173] For presentation purposes, these amounts represent the average O&M amounts for a residential customer only.
[174] Variable Margin for Rate Schedule 1.

The inputs in Table 7.1 were derived as follows:

- SI: The individual entity rates are a carry-forward of the rates used for the 2009-2011 MX Test System Improvement rates. The individual entity rates are then weighted by the 2013 projected total average customers[175] to arrive at the amalgamated SI fee.
- Discount Rate: The individual entity discount rates are derived by using the 2013 forecasted before-tax cost of capital[176] and adjusting the debt components to an after-tax rate.[177] The amalgamated discount rate is derived by using the financial schedules included in this Application[178] and performing the same calculations to determine an amalgamated after-tax cost of capital.
- O&M: The individual entity O&M per customer was derived using the 2011 MX Test residential O&M rates[179] and applying an annual inflation rate to arrive at the 2013 amounts per customer. The individual entity rates are then weighted by the 2013 projected average residential customers[180] to arrive at the amalgamated O&M per residential customer.
- Property tax: The property tax input was derived as per 2012-2013 RRA responses to BCUC IR 1.83.0 and BCUC IR 2.40.0 (refer to Appendix C-10).
- Variable and Fixed Margins: The variable and fixed margins are as provided in Appendix J-3, Tariff Continuity and Bill Impact Schedules.

The FEU performed analysis on the FEI, FEVI and FEW main extension populations from 2008-2010 to determine the impact of implementing the FEI Amalco input parameters on historical MX Test results. The FEU generated random samples from FEI, FEVI and FEW[181] main extensions from 2008-2010 and then re-ran the MX Tests holding all inputs constant except the six listed above. For comparison purposes, the main extension samples were re-run under the following scenarios:

1. Using the inputs of the three individual utilities (FEI, FEVI & FEW); and
2. Using the inputs of the Amalgamated Entity.

The PI results of the two scenarios were then compared to determine the impact of amalgamation on main extensions on FEI, FEVI and FEW customers and on FEU customers in aggregate. As seen below, results of this analysis indicate that in aggregate FEU customers

175 Appendix H-1 through H-3, Schedule 17, total of column 9.
176 Appendix H-1 through H-3, Schedule 81, Line 16, column 6.
177 Appendix H-1 through H-3, Schedule 81 column 6, Lines 11 and 13 multiplied by 1 – tax rate (1 – 25% = 75%).
178 Appendix J-1, Schedule 30, Column 5.
179 $86 for FEI customers, $70 for FEVI customers, and $62.48 for FEW customers.
180 Appendix H-1 through H-3, Schedule 16, Line 3, Column 9.
181 In the case of FEW, all MX Tests were re-run given the small population of main extensions.

would have experienced no material changes resulting from amalgamation. The aggregate results of this analysis are found in the table below.

Table 7-2: Aggregate PI Values Resulting from Amalgamation

	2008 PI		2009 PI		2010 PI	
Utility	**Individual Utilities**	**Amal-gamated**	**Individual Utilities**	**Amal-gamated**	**Individual Utilities**	**Amal-gamated**
FEI	1.5	1.6	1.7	1.9	1.5	1.7
FEVI	1.7	1.1	1.4	0.9	2.0	1.2
FEW	N/A[182]	N/A	4.8	1.8	1.0	0.4
Average	1.5	1.5	1.7	1.6	1.6	1.4

The 2009 PI Individual Utilities column, for example, represents the results of re-running the MX Tests for a sample of 2009 main extensions with the 2013 FEI, FEVI and FEW inputs from Table 7-1. The average PI value of 1.7 in this column represents an average of the sum of the three individual utilities. In comparison, the 2009 PI Amalgamated column represents the same sample of 2009 main extensions re-run with the 2013 FEI Amalco values from Table 7-1.

From the 2008-2010 main extension analysis, the following conclusions can be made:

- Overall amalgamation would have minimal impact on PI values as seen by the fact that the average PI values would have been reduced by 0.1 on average;
- PI values for FEI customers would have increased as seen by the fact that the PI value increased in 2008, 2009 and 2010 when using the inputs of the amalgamated entity; and
- PI values for FEVI and FEW customers would have decreased as seen by the fact that PI values decreased in 2008, 2009 and 2010 when using the inputs of the amalgamated entity.

Table 7-3 provides similar analysis as Table 7-2 except that it shows the range of PI results.

Table 7-3: Individual PI Value Range Resulting from Amalgamation

	2008 PI Range		2009 PI Range		2010 PI Range	
Utility	**Individual Utilities**	**Amal-gamated**	**Individual Utilities**	**Amal-gamated**	**Individual Utilities**	**Amal-gamated**
FEI	0.9 - 2.3	1.0 - 2.6	1.0 - 7.4	1.1 - 8.0	1.0 - 3.8	1.2 - 4.3
FEVI	1.0 - 2.4	0.6 - 1.5	1.0 - 2.3	0.6 - 1.6	1.0 - 3.3	0.6 - 2.0
FEW	N/A	N/A	4.8 - 4.8	1.8 - 1.8	0.8 - 1.5	0.3 - 0.6

[182] There were no Main Extensions completed in Whistler in 2008 and only 1 Main Extension in 2009.

As noted above, FEVI and FEW customers' PI values would decrease as a result of amalgamation. Lower PI values mean that on a portfolio basis it may be more difficult to attach customers that had previously been deemed to be economical using the individual and aggregate PI thresholds of 0.8 and 1.1 mentioned earlier. The results from FEVI in 2009 showing the PI value decreasing from 1.4 to 0.9, for example, suggest that under amalgamation, more FEVI customers will be required to provide a CIAC to achieve the required PI thresholds.

In contrast, FEI customers' PI values would increase as a result of amalgamation, suggesting that fewer FEI customers will be required to provide a CIAC to achieve the required thresholds.

Overall, amalgamation would have minimal impact on the number of customers required to provide a CIAC to achieve the required PI thresholds.

In summary, the FEU believe the continuation and application of the FEI and FEVI approved MX test, with the same established PI thresholds, to the Amalgamated Entity is in the best interest of its customers.

7.4.3 A COMBINED APPROACH TO GAS SUPPLY

The FEU are seeking approval for a combined natural gas procurement portfolio as part of this Application. Combining the current separate gas procurement portfolios and the associated policies and rate constructs as part of the amalgamation will provide a consequential benefit to customers. The potential benefits of a single gas procurement portfolio include greater operational effectiveness, expanded contracting flexibility, and regulatory efficiency. While the Company anticipates a number of benefits from the creation of a single combined portfolio, this change is not expected to provide immediate cost savings in any material way. This change however, will allow the Company to optimize the portfolio so that cost savings can be realized over the longer term. The benefits expected from the creation of a single combined portfolio are reviewed below in greater detail.

In the event that the amalgamation is not approved, FEI and FEVI would continue to maintain separate gas supply portfolios.

7.4.3.1 Annual Contracting Plan ("ACP")

If amalgamation is approved, the FEU will develop a single combined gas portfolio to meet the requirements for all regions served by FEI Amalco. While moving to a single portfolio is not expected to deliver immediate commodity or midstream savings, a combined portfolio structure should enable greater operational effectiveness, expanded contracting flexibility, and regulatory efficiency.

Operational Effectiveness

The total pool of available resources can be more effectively utilized within a single portfolio in order to better manage the total system load on a daily basis. Within a combined portfolio only a single set of nominations will be required each day on the various pipeline systems. The Amalgamated Entity will be able to access gas supply from a broader pool of resources at short notice each day in order to meet the total intraday load, especially during periods of cooler weather when more resources are required. Additionally, diversity from a single set of total available resources to service the entire system load of the Amalgamated Entity and the ability to match resources available in the region to the combined system load, is expected to enable greater efficiency over the long term from a resource contracting and deployment perspective.

Contracting Flexibility

A single set of counterparties would be available to contract and procure gas supply resources. Currently, FEI has a broad range of counterparties available for entering into contracts with, given the attractiveness of the size of its resource requirements and its credit depth. By effectively utilizing the broader group of counterparties available to FEI, and contracting for supply under a single portfolio, FEI Amalco will be better able to manage master supply arrangements, nominations, and month-end accounting processes.

Over the past few years, producer companies have been bought and sold resulting in changes to, or elimination of, counterparty contracts, thus requiring FEI and FEVI to separately modify and notate their individual master purchase agreements. A single set of counterparties will result in only one master agreement with a supplier, and any modifications will need to be administered only once, including filings with the Commission. Furthermore, as new creditworthy counterparties emerge in the industry, FEI Amalco will have to negotiate only a single master agreement in order to serve all customers. Within a combined portfolio, the FEU may also be able to realize a greater degree of resource optimization due to the availability of a larger portfolio of resources that can be combined with a single diverse set of counterparties.

Regulatory Efficiency

The development of a single gas portfolio will result in streamlining the preparation and submission of key gas supply filings with the BCUC, such as the ACP and energy supply contracts, while eliminating the need for intercompany subleasing agreements for storage contracts. This would reduce the number of filings and issuance of orders for the individual entities of the FEU by the BCUC.

Cost Allocation

Currently, the allocation of gas costs for FEI and FEW are made from a single portfolio utilizing the FEI gas cost allocation methodology for commodity and midstream costs across the various rate classes. The FEW natural gas supply requirements have been incorporated within the FEI portfolio since January 1, 2010. In order to implement this methodology across the FEU, the various rate classes of FEFN, FEVI and FEW have been mapped to a consistent set of rate classes so that gas costs can be allocated across the FEU out of a single portfolio of gas costs.

The development of a consistent set of rate classes required for gas cost allocation across the FEU is presented in detail in Section 9.

In order to effectively implement and manage a single gas portfolio across a fully amalgamated entity, the FEU believe that the gas cost accounting methodology currently used by FEI, combined with the extension of the ESM, will accomplish this objective. Extending the ESM across all the FEU gas utilities is necessary to enable the provision of commodity unbundling and greater choice to customers not currently able to participate in this program.

7.4.3.2 Price Risk Management

Price risk management includes activities that mitigate the impact of market price volatility on customers' commodity rates. FEI and FEVI have historically used both physical and financial tools to manage this impact. Physical tools include those defined within the ACPs for FEI and FEVI, such as diversification of daily and monthly index priced supply, and the use of storage capacity to use summer priced gas for winter load requirements. Financial tools, outlined within the respective Price Risk Management Plans, have included the use of derivatives, or hedges, to convert index priced supply into fixed, or capped, price supply. These physical and financial tools are particularly useful during periods of extreme market volatility.

Looking forward, if the amalgamation and rate harmonization is approved, it is anticipated that a single set of price risk management activities will be developed along with the physical resources per the ACP. This would provide greater regulatory efficiency as the Amalgamated Entity would then be able to submit a single annual price risk management plan to the BCUC for approval.

7.4.3.3 Gas Supply Mitigation Incentive Program ("GSMIP")

FEI has had long standing incentive mechanisms supporting gas supply mitigation activities while FEVI, FEW, and FEFN have not. FEW started receiving benefits from FEI's GSMIP when the FEI and FEW gas portfolios were amalgamated in January 2010.

FEI recently worked with key stakeholders to develop a new incentive mechanism supporting gas supply mitigation activities that aligns the interests of the Company and its customers.[183] This new incentive mechanism is designed to encourage the delivery of value to customers and rewards the ongoing efforts of the Company that are over and above what is reasonably expected in the normal stewardship of a utility's business. The program was approved by the Commission pursuant to Order G-163-11 for the two year period ending October 31, 2013 at which time FEI expects to apply for renewal of the program.

Under the Amalgamated Entity a single gas portfolio would be created that would serve the combined requirements of FEI Amalco, which would optimize the portfolio as a whole. It is

[183] Details on the revised incentive mechanism, including a description of the mechanism, the design objectives of the plan and the overall benefits to customers, are set out in the GSMIP Application dated September 14, 2011.

expected that GSMIP would apply to the new single portfolio which would be addressed in any application for renewal beyond the current term approved by the Commission. The resource base eligible for the incentive mechanism will increase under an amalgamated entity but this should have no impact on the overall mitigation strategy.

7.4.4 OTHER OPERATIONAL IMPLICATIONS

For the most part, the other operational implications associated with the amalgamation and adoption of postage stamp rate structures will be relatively minor. On a day-to-day basis, the Companies are operated through a single management structure, with O&M costs allocated based on a shared services formula. As such, most employees will see little difference. There are, however, some changes that will be required from a Corporate Services, Customer Service, and IT and Billing Systems perspective.

7.4.4.1 Corporate Services

Each of the three Utilities currently has a Corporate Services Agreement with FHI, for the provision of identified corporate services in exchange for a specified fee. These arrangements must be modified to reflect the amalgamation. The FEU are seeking an order to discontinue the agreements with FEVI and FEW, and maintain the agreement with FEI with the fees amended to reflect the amounts now required for the Amalgamated Entity. The corporate services fee between FHI and the Amalgamated Entity is a simple addition of the corporate service fees between FHI and FEI, FEVI and FEW, and therefore, is unchanged from the amount filed in the 2012-2013 RRA. A draft corporate services agreement between FHI and the Amalgamated Entity is attached in Appendix F. This agreement would become effective on the date of amalgamation.

7.4.4.2 Customer Service

If amalgamation is approved, contact centre training is scheduled to start in the latter half of 2013 and is expected to run for approximately 3 months. During this step, Customer Service Representatives in both contact centres (Burnaby and Prince George) would receive training on amalgamation and common rates. The costs associated with this effort will be captured in the Amalgamation Costs Deferral Account that is described in Section 8.2.1.2.1.

7.4.4.3 IT and Billing Systems

Upgrades to IT and Billing Systems are scheduled to start immediately after Commission approval is received and are expected to run for approximately 6 months. During this upgrade all configuration, development of reports, interfaces, and data conversion programs will be developed and unit tested for all billing related systems. The costs associated with this effort will be captured in the Amalgamation Costs Deferral Account that is described in Section 8.2.1.2.1.

7.4.5 SUMMARY OF OPERATIONAL EFFECTS OF AMALGAMATION

In summary, the operational implications associated with amalgamation and adoption of common rate structures will involve:

- Replacing the existing Terms & Conditions for each of the companies with a common set of GT&Cs for FEI Amalco. The common set of GT&Cs, similar to those of the current FEI service area, will harmonize tariff, rate design principles and rate classifications across all areas served by FEI Amalco. The FEI Amalco will also employ the approved FEI/FEVI MX Test.
- Combining the current separate gas procurement portfolios and the associated policies and rate constructs.
- Some other minor operational changes that will be required from the Corporate Services, Customer Service, IT and Billing Systems perspectives.

The other operational implications associated with the amalgamation and adoption of postage stamp rate structures will be relatively minor.

8 OVERVIEW OF PROPOSED COMMON RATES OF THE AMALGAMATED ENTITY

In this section, the FEU provide an overview of the proposed common rates for the Amalgamated Entity. As will be discussed in detail in this section, the proposed common rates are based on the 2013 cost of service and rate base of the individual utilities with adjustments for the effects of amalgamation and are based on a return on equity using the current benchmark and existing premiums for FEVI and FEW that are in effect at the time of filing. As discussed in section 2, time is required to implement the common rates such that the proposed implementation date is January 1, 2014. In addition, the Commission has initiated the Generic Cost of Capital Proceeding which will establish a benchmark ROE and anticipates a subsequent process for determining any risk premiums for individual utilities. The rates are therefore proposed to be interim only as they will need to be updated to reflect 2014 costs (which the FEU will do through a 2014 revenue requirements application to be filed in 2013) and to reflect the return on equity of the Amalgamated Entity as a result of the GCOC Proceeding and any related subsequent proceeding. The 2014 midstream and commodity rates will also need to be set for the Amalgamated Entity through the 2013 fourth quarter gas cost filing. It is nonetheless essential to have a rate approved for the Amalgamated Entity upon amalgamation on January 1, 2014 so that there is a rate in place for the Amalgamated Entity pending the updates discussed above. Having rates for January 1, 2014 based on 2013 costs is also important to provide, in effect, a 2013 approved rate for the Amalgamated Entity which the 2014 revenue requirement application can use as a comparator for the proposed 2014 final rates.

This section provides an overview of the common rates of the Amalgamated Entity. In particular:

- Section 8.1 discusses the cost of service of the Amalgamated Entity.
- Section 8.2 discusses the rate base of the Amalgamated Entity.
- Section 8.3 discusses the return on equity/cost of capital of the Amalgamated Entity.
- Section 8.4 discusses the 2014 common rates for the Amalgamated Entity.

8.1 Amalgamated Cost of Service

The first step in arriving at appropriate common rates for FEI Amalco is to determine the combined cost of service. It forms the basis for a COSA analysis, which determines the cost of service for various rate classes. The basis for the COSA undertaken by the FEU with the assistance of external rate design experts is the summation of the 2013 cost of service of the individual utilities as sought in the 2012-2013 RRA, adjusted to account for changes in line items that will occur upon amalgamation. The scope of this Application is limited to a discussion of the changes that result from amalgamation.

The FEI Amalco total cost of service of $1,504.8 million ($766.9 million delivery cost of service) for the 2013 test year is determined by adding the stand-alone cost of service for FEI, FEVI, FEW and Fort Nelson and then adjusting for entries described in more detail in Section 8.1.1 below.[184]

Table 8-1: 2013 Amalgamated Cost of Service[185]

($ thousands)	FEI	FEVI	FEW	FN	Total	Adjustments	FEI-Amalco	COSA Adjustments	COSA Total
	2013								
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Cost of Gas Sold (Including Gas Lost)	$ 658,568	$ 77,435	$ 3,455	$ 2,945	$ 742,403	$ (4,418)	$ 737,985	$ (114,965)	$ 623,020
Net Cost of Gas	658,568	77,435	3,455	2,945	742,403	(4,418)	737,985	(114,965)	623,020
Operation and Maintenance	207,349	35,107	3,338	784	246,578	(2,564)	244,014		244,014
Property and Sundry Taxes	51,239	10,263	244	178	61,924	-	61,924		61,924
Depreciation and Amortization	145,189	36,408	1,558	338	183,493	(28)	183,465		183,465
NSP Provision				(97)	(97)	-	(97)		(97)
Other Operating Revenue	(24,789)	(18,675)	(16)	(24)	(43,504)	3,485	(40,019)	(37,889)	(77,908)
Income Taxes	28,988	7,312	506	28	36,834	(92)	36,742		36,742
Earned Return	219,006	60,071	2,892	719	282,688	(1,868)	280,821		280,821
Delivery Cost of Service	626,982	130,486	8,522	1,926	767,916	(1,066)	766,850	(37,889)	728,961
Total Cost of Service	$ 1,285,550	$ 207,921	$ 11,977	$ 4,871	$ 1,510,319	$ (5,484)	$ 1,504,835	$ (152,854)	$ 1,351,981

As shown in Table 8-1 above, the ongoing amalgamated cost of service will be reduced by a forecast of $5.5 million, which includes an approximate cost of service reduction of $3.0 million related to transportation charges paid from FEW and FEI to FEVI. These transportation charge related reductions to the cost of service are equally offset by reductions to revenue (i.e., although the costs have decreased by $3.0 million, the revenue will also decrease by $3.0 million, resulting in a net rate impact of nil). Therefore, the net reduction to the cost of service is $2.5 million and is mainly related to short term interest expense. For purposes of the COSA study only, a restatement of Other Revenue is required as shown in column 9 and discussed further in Section 9.6.2.5, in addition to an update to the Cost of Gas as shown in column 9 and previously discussed in Section 3.2.2.2.

8.1.1 AMALGAMATION ADJUSTMENTS TO THE COST OF SERVICE

The cost of service for FEI Amalco must reflect the removal of intercompany items that will be eliminated upon amalgamation and rate harmonization. The adjusting entries that are required to arrive at the 2013 amalgamated cost of service are as follows:

8.1.1.1 Cost of Gas

There are two adjustments totalling a decrease of approximately $4.4 million to arrive at the FEI Amalco cost of gas. Neither of these adjustments reflect a change in costs; rather, they reflect a change in the allocation of costs and the elimination of an intercompany item, respectively.

[184] Appendix H-1 through H-4, The stand-alone cost of service for FEI and FEW are from Section 7, Tab 7.1 and 7.3, Schedule 6 of the September 12th Evidentiary Update to the Revenue Requirement application (Exhibit B-21). The stand-alone cost of service for FEVI reflects the most recent financial schedules as provided in the 2012-2013 RRA hearing (Exhibit B-52, Undertaking Number 24, Schedule 6). The stand-alone cost of service for Fort Nelson reflects the allocation of the 2012 revenue surplus to 2013 and filed as Exhibit B-66 in 2012-2013 RRA.

[185] Appendix J-1, Schedule 1.

1. Company Use and Unaccounted for Gas Costs: The allocation of costs between delivery and gas costs as they pertain to company use gas, unaccounted for gas and gas control management differs between the stand-alone Vancouver Island and Mainland regions. To align and simplify the treatment of these costs in FEI Amalco, as discussed in Section 9.6.2.4, the company own use, unaccounted for gas and gas control management costs of approximately $4.0 million have been transferred from cost of gas to the FEI Amalco O&M expense.

3. Squamish Transportation Charges: The Squamish transport charges paid by FEI to FEVI of approximately $0.4 million are accounted for as a cost of gas in the Mainland region but as revenue in the Vancouver Island region; therefore the cost of gas has been adjusted to remove these costs. This reduction to the FEI Amalco cost of gas is equally offset by a reduction to the FEI Amalco revenue.

8.1.1.2 Operating and Maintenance Expense (including FEVI Transportation Costs)

The adjustment to the FEI Amalco gross O&M expense reflects the allocation of the company use, unaccounted for gas and gas control management costs of approximately $4.0 million, as described above. Taking into consideration the impact of capitalized overhead, the impact to net O&M expense is an increase of $3.5 million.[186] Further, for purposes of Table 8-1, the FEI Amalco transportation costs have been included in the operating and maintenance expense and require adjustments as described in more detail below.

There are two adjustments required to arrive at the FEI Amalco transportation costs, both of which reflect the elimination of intercompany agreements that will cease to exist upon amalgamation:

1. The Whistler transport charges of approximately $2.5 million paid by FEW to FEVI are accounted for as transportation costs in Whistler but as revenue in Vancouver Island; therefore the transportation costs have been adjusted to remove these costs. This reduction to the FEI Amalco transportation costs is equally offset by a reduction to the FEI Amalco revenue.

4. The Coastal Transmission System wheeling charges paid by FEVI to FEI of approximately $3.5 million reside in the other operating revenues of Mainland and the transportation costs of Vancouver Island; therefore, both transportation costs and other revenue have been adjusted to remove this amount.

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[186] As per the 2012-2013 RRA, FEI Amalco gross operating and maintenance expense is subject to an overheads capitalization rate of 14%. Thus the impact to net O&M is the gross O&M amount of $4.0 million x (1 – 14%). Please refer the 2012-2013 RRA, Exhibit B-1, Section 5.3.17, p, 267.

8.1.1.3 Depreciation and Amortization Expense

The decrease of approximately $0.03 million to the FEI Amalco depreciation and amortization expense reflects the elimination of the net difference in the amortization related to the $14.55 million contribution in aid of construction provided by FEW to FEVI for the Whistler Pipeline.

8.1.1.4 Other Revenue

The FEI Amalco Other Revenue has been reduced by $3.5 million to reflect the elimination of the wheeling agreement between Vancouver Island and Mainland as described above.

8.1.1.5 Income Taxes

The income tax expense for FEI Amalco has been calculated using the flow-through (taxes payable) method, consistent with the 2012-2013 RRA, at the 2013 corporate tax rate of 25.0 percent. As such, the changes in rate base and earned return applicable to FEI Amalco result in a decrease to tax expense of approximately $0.09 million.

Earned Return

As referred to in Section 6.6.3, and provided in Appendix J-1 (Schedule 3, Column 7, Lines 11 and 16), a significant cost of service impact of amalgamation arises from changes in interest expense. Net interest expense savings of approximately $2.0 million are forecast to occur upon amalgamation of the Utilities. The approximate $2.2 million in savings associated with short-term interest expense is forecast based on approximately $144.2 million of Vancouver Island and Whistler short-term debt[187] being financed at the Mainland short-term debt rate[188]. The FEU believe it is appropriate to use the Mainland short-term debt rate because it is likely that only one credit facility would be required upon amalgamation. An increase in the FEI Amalco long term interest expense of approximately $0.2 million slightly offsets the forecast savings, for a net savings in interest expense of approximately $2.0 million.[189] The FEU do not anticipate any other changes to long-term debt issuances or retirements, compared to the amounts shown in the 2012-2013 RRA schedules, as a result of amalgamation; therefore, additional costs or savings associated with long term interest expense are not forecast.

Finally, adjustments to the FEI Amalco rate base as discussed in Section 8.2.1 and the rounding of the weighted average ROE to two decimal places, result in a combined change to the FEI Amalco equity earned return of approximately $0.1 million.

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[187] FEVI short-term debt of $139.4M is shown on FEVI RRA financial schedules (Appendix H-2), Schedule 81, Row 13, Column 3. FEW short-term debt of $4.8M is shown on FEW RRA financial schedules (Appendix H-3), Schedule 81, Row 13, Column 3.

[188] $2.2M in Short-term debt savings calculation: $139.4M in FEVI short-term debt x (3.5% FEI short-term debt rate – 5.0% FEVI short-term debt rate) = ($2.1M). $4.8M in FEW short-term debt x (3.5% FEI short-term debt rate – 4.5% FEW short-term debt rate) = ($0.1M). FEI, FEVI and FEW short-term debt rates are shown in the respective RRA financial schedules (Appendix H-1 through H-3), Schedule 81, Column 5, Row 13.

[189] Appendix J-1, Schedule 31, Line 2, the net proceeds of the issue for the Series B Purchase Money Mortgage is based on the FEI capital structure; therefore, the weighted average capital structure under FEI Amalco results in a change to the net proceeds and corresponding change to the annual interest cost for Series B.

8.2 Amalgamated Rate Base

The FEI Amalco rate base of $3,678.0 million for the 2013 test year is determined by adding the stand-alone rate bases for FEI, FEVI, FEW and Fort Nelson and then adjusting for entries described in more detail in Section 8.2.1 below.[190]

[190] Appendix H-1 through H-4, Schedule 41, Column 5.

Table 8-2: Amalgamated Rate Base

($ thousands)	FEI	FEVI	FEW	FN	Total	Adjustments	FEI-Amalco	COSA Adjustments	COSA Total
	2013								
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Gas Plant in Service, Beginning	$ 3,782,696	$ 1,317,658	$ 17,203	$ 12,563	$ 5,130,120	$ 10	$ 5,130,130	$ (4,072)	$ 5,126,058
Opening Balance Adjustment	-	-	-	-	-	-	-	-	-
Gas Plant in Service, Ending	3,914,282	1,344,601	17,637	12,957	5,289,477	575	5,290,052	(6,635)	5,283,417
Accumulated Depreciation Beginning - Plant	$ (1,015,186)	$ (318,572)	$ (2,933)	$ (2,673)	$ (1,339,364)	$ (2)	$ (1,339,366)	$ 243	$ (1,339,123)
Opening Balance Adjustment	-	-	-	-	-	-	-	-	-
Accumulated Depreciation Ending - Plant	(1,107,354)	(347,083)	(3,200)	(3,033)	(1,460,670)	(7)	(1,460,677)	672	(1,460,005)
Negative Salvage - Beginning	$ (6,812)	$ (12,477)	$ (74)	$ -	$ (19,363)	$ -	$ (19,363)	$ -	$ (19,363)
Opening Balance Adjustment	-	-	-	-	-	-	-	-	-
Negative Salvage - Ending	(10,677)	(15,875)	(150)	-	(26,702)	(1)	(26,703)	-	(26,703)
CIAC, Beginning	$ (183,107)	$ (254,306)	$ (186)	$ (1,287)	$ (438,886)	$ 14,549	$ (424,337)	$ -	$ (424,337)
Opening Balance Adjustment	-	-	-	-	-	-	-	-	-
CIAC, Ending	(189,803)	(250,614)	(186)	(1,287)	(441,890)	14,549	(427,341)	-	(427,341)
Accumulated Amortization Beginning - CIAC	$ 50,332	$ 63,319	$ 22	$ 556	$ 114,229	$ (757)	$ 113,472	$ -	$ 113,472
Opening Balance Adjustment	-	-	-	-	-	-	-	-	-
Accumulated Amortization Ending - CIAC	56,228	67,506	27	590	124,351	(1,010)	123,341	-	123,341
Net Plant in Service, Mid-Year	$ 2,645,300	$ 797,079	$ 14,080	$ 9,193	$ 3,465,651	$ 13,953	$ 3,479,604	$ (4,896)	$ 3,474,708
Adjustment to 13-Month Average	-	-	-	-	-	-	-	-	-
Work in Progress, No AFUDC	17,110	2,285	23	-	19,418	-	19,418	-	19,418
Unamortized Deferred Charges	49,909	5,355	26,550	33	81,847	(13,437)	68,410	-	68,410
Cash Working Capital	(2,256)	529	58	11	(1,658)	691	(967)	11,277	10,310
Other Working Capital	101,622	10,436	635	4	112,697	-	112,697	(11,277)	101,420
Future Income Taxes Regulatory Asset	282,359	76,663	2,319	-	361,341	-	361,341	-	361,341
Future Income Taxes Regulatory Liability	(282,359)	(76,663)	(2,319)	-	(361,341)	-	(361,341)	-	(361,341)
LILO Benefit	(1,150)	-	-	-	(1,150)	-	(1,150)	-	(1,150)
Utility Rate Base	$ 2,810,535	$ 815,684	$ 41,346	$ 9,241	$ 3,676,805	$ 1,207	$ 3,678,012	$ (4,896)	$ 3,673,116

As shown in Table 8-2 above, the amalgamated rate base increased by a forecast of approximately $1.2 million as compared to the summation of the stand-alone companies. This increase is largely attributable to the application of the Mainland net lead-lag days in the determination of cash working capital for FEI Amalco. For purposes of the COSA study only, a restatement of net plant in service, in addition to an adjustment between cash working capital and other working capital, is required as shown in column 9.[191] This decrease of $4.9 million does not impact the FEI Amalco rate base.

8.2.1 AMALGAMATION ADJUSTMENTS TO RATE BASE

The rate base for the Amalgamated Entity will reflect the combined rate base of the FEU as approved in the 2012-2013 RRA, with adjustments. As is the case with the FEI Amalco cost of service, the rate base for the Amalgamated Entity must reflect intercompany items that will be eliminated upon amalgamation and rate harmonization. A discussion on the derivation of the FEI Amalco rate base, as well as the required adjusting entries, follows below.

8.2.1.1 Net Plant in Service

The FEI Amalco net plant in service reflects the consolidation of Mainland, Vancouver Island, Whistler and Fort Nelson property, plant and equipment by applicable account, and adjusted for elimination entries amongst the Companies. The depreciation expense and the accumulated depreciation balances reflect the depreciation rates based on the most recent Gannett Fleming Depreciation Study and proposed by the FEU in the 2012-2013 RRA. That is, for each asset account the depreciation rates as shown in Column 3 of Schedules 19-21 of Appendix J-1, are calculated as the sum of the FEI, FEVI, FEW and Fort Nelson 2013 depreciation expense divided by the sum of the FEI, FEVI, FEW and Fort Nelson 2013 gross plant in services balances for depreciation (Column 2 of Schedules 19-21). Similarly, the removal provision and the negative salvage balances reflect the negative salvage rates as proposed in the 2012-2013 RRA.

Adjustments to the contribution in aid of construction and accumulated amortization of contribution in aid of construction balances are required to eliminate the intercompany transaction resulting from the $14.55 million contribution provided by Whistler to Vancouver Island for the Whistler Pipeline. This is largely[192] offset by a corresponding adjustment to the unamortized deferred charges for the same purpose.

8.2.1.2 Unamortized Deferred Charges

The FEI Amalco mid-year balance of unamortized deferred charges, and the 2013 amortization expense pertaining to deferred charges, reflects the consolidation of Mainland, Vancouver

191 The reduction reflects the removal of the biomethane purification plant from rate base since the cost of service is charged to the Biomethane Variance Account (BVA) and recovered through the Biomethane Energy Recovery Charge (BERC).

192 There is a minimal variance due to the slight differences in amortization rates between FEVI and FEW (1.73% vs. 2% respectively.

Island, Whistler and Fort Nelson accounts. That is, the 2013 opening balance in rate base deferral accounts and the 2013 amortization expense as identified in the 2012-2013 RRA for Mainland, Vancouver Island, Whistler and Fort Nelson have been added together and included in the FEI Amalco rate base and reflected in the FEI Amalco amortization expense. The adjustment to FEI Amalco unamortized deferred charges, as shown in Table 8-2, is for the elimination of the intercompany transaction between Whistler and Vancouver Island pertaining to the Whistler Pipeline.

In the 2012-2013 RRA, the Companies proposed alignment of the amortization periods for similar deferral accounts. As outlined in Section 6.3 of the 2012-2013 RRA (Exhibit B-1), Whistler and Fort Nelson have proposed changes to the amortization periods for the Property Tax and Interest Variance accounts and Whistler has proposed changes to the amortization periods for the Revenue Stabilization Adjustment Mechanism ("RSAM") and the Tax Variance accounts to align with the Mainland amortization period for each of those accounts. If this proposal to align the treatment of deferral accounts is approved, all deferral accounts of a similar nature will be amortized over the same period and therefore, upon amalgamation, the balances of these accounts, as well as the corresponding amortization expense, are consolidated without adjustments required to FEI Amalco.

With respect to the Margin Related deferral accounts recovered through rate riders and the commodity or midstream rates (Appendix J-1, Schedule 24, Lines 2 through 4), FEU is proposing the following:

- To combine the closing balance in the existing Mainland, Fort Nelson and Whistler RSAM accounts (including interest) and to determine Rate Rider 5 based on the FEI Amalco harmonized rate schedules and volumes (FEI Amalco Rate Schedules 1, 1B, 1U, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23) when rate harmonization occurs. The projected credit RSAM rider of $0.026/GJ effective January 1, 2014 and applicable to FEI Amalco, is provided on Schedule 32 of Appendix J-1. The actual RSAM Rider that will be in place will be determined when rate harmonization occurs.
- To consolidate the December 31, 2013 balances in the FEVI GCVA and the FEFN GCRA gas cost deferral accounts, with the balances in the FEI and FEW Midstream Cost Reconciliation Accounts to form the FEI Amalco Midstream Cost Reconciliation Account, and to consolidate the December 31, 2013 balances in the FEI and FEW Commodity Cost Reconciliation Accounts to form the FEI Amalco Commodity Cost Reconciliation Account, both effective January 1, 2014. A discussion of the amalgamated cost of gas and the proposed allocation and recovery of costs as between Commodity and Midstream can be found in Section 9.

Additionally, in this Application, FEI Amalco is proposing four new deferral accounts and is seeking approval for the disposition of the RSDA effective January 1, 2014.

Amalgamation Costs Deferral Account (New)

This rate base deferral account will record the costs pertaining to amalgamation as set out in this Application.[193]

The estimated total cost of amalgamation is expected to be approximately $2 million and includes legal and transactional costs to amalgamate and operational costs of implementation such as training contact centre employees and IT system changes.

As discussed earlier, the Companies do not expect that there will be material cost savings in 2014 (with the exception of savings related to debt financing which has already been reflected in the amalgamated cost of service and will not be captured in the deferral account), 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 2013 period there will be only some small savings in 2014. These savings would be limited to reporting efficiencies such as financial, legal and regulatory reporting and debt issuance requirements (described in Section 6). While the costs related to the amalgamation and implementation of postage stamp rates are one-time in nature, any efficiency savings, although not large, will be on-going, and are expected to offset the cost of amalgamation over time. It is the intention of the FEU to pass on to customers the full benefit of any of the cost savings achieved in 2014 and later years that are associated with amalgamation and rate harmonization, as these savings will be forecast as part of the 2014 and future revenue requirements.

Thus, FEU is requesting approval for a deferral account to capture the costs of amalgamation, incurred in 2014 for future recovery from customers. The amortization period for this account will be determined in a future revenue requirement proceeding.

The Company Use and Unaccounted for Gas Cost Variance Account (New)

This rate base deferral account will capture the variances in the company use and unaccounted for gas costs between the actual costs incurred and the forecast costs embedded in the amalgamated O&M expense. As described in Section 9.6.2, the recovery of the company use and unaccounted for gas costs as part of O&M expense aligns the recovery of the costs with the non-bypass customers who both cause and benefit from them; consistent with the principle of cost causality, it follows that any variances between the forecast and actual incurred costs of company use and unaccounted for gas for FEI Amalco should be recovered from or refunded to those same customers.

The company use and unaccounted for gas costs for FEI Amalco forecast in the 2013 test year total approximately $6 million, approximately $2 million already included in O&M and the $4 million in FEVI which is shown as an adjusting item in Table 8-1 above, and costs incurred in the future could be materially higher as the forecast is based on the relatively low natural gas

[193] This same request was made, and subsequently withdrawn, in the 2012-2013 RRA. See Appendix C-10 (2012-2013 RRA Appendix C-11, Section 8: Approvals Sought and Proposed Regulatory Process, p. 772).

prices currently being seen in the markets. Variances between the forecast and actual incurred costs of company use and unaccounted for gas are substantially the result of fluctuations in the price of natural gas and system load variations, which are both outside the FEU's control. Further, capturing the variances in this deferral account maintains the existing FEI treatment where all variances are recovered from or refunded to customers; variances are not currently, nor in the future should be, at the risk of FEI or the FEU.

Additions to this account have not been forecast and any variances will be accumulated and amortized in rates over a one year period, commencing in 2015.

The Amalgamation and Rate Design Application Costs Deferral Account (New)

This non-rate base deferral account attracting Allowance for Funds Used During Construction ("AFUDC") will capture the costs associated with this Application. Costs incurred consist of application and hearing-related 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, stakeholder consultation and miscellaneous facilities, stationery and supplies costs. Costs for the Application are forecast at approximately $1.5 million. The amortization period for this account will be determined in a future revenue requirement application.

Fort Nelson Phase-In Rate Rider Deferral Account (New)

The rate rider mechanisms associated with this non-rate base account attracting interest will be used to phase-in the impact of postage stamp rates for the Fort Nelson region over a 15 year time period. This deferral account will capture the annual account additions and the recoveries from the rate rider mechanism(s) used to phase-in postage stamp rates in Fort Nelson. The methodology for the determination of the Fort Nelson Phase-In Rate Rider(s) effective January 1, 2014 is described in Section 8.4.1.1.

RSDA (Disposition)

Commission Order No. G-140-09 approved the creation of the non-rate base 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, for FEVI. In the 2012-13 RRA, the FEU sought approval for the continuation of the RSDA for 2012 and 2013.[194] Upon amalgamation in 2014 the RSDA will no longer be required to capture the difference in net revenues received and the actual cost of service and as such, disposition of the balance in the account is required. For reasons described in Section 8.4.1.3, the FEU are seeking approval in this Application for a rate rider mechanism to return the December 31, 2013 balance in the RSDA over a three year period to non-bypass Mainland customers effective January 1, 2014.

Proposed changes to and discontinuances of Margin Related deferral accounts, as well as the request for new deferral accounts and the disposition of the RSDA, are outlined in Figure 8-1

[194] Appendix C-10 (2012-2013 RRA, Exhibit B-1, Section 3.4.2, pages 72 and 73).

and Table 8-3 below. Please note that Table 8-3 is limited to the deferral account changes required for amalgamation and postage stamp rates. All other deferral accounts, as provided in Schedules 24 and 25 of Appendix J-1, will continue as currently approved or proposed in the 2012-13 RRA, and require no change for the purpose of amalgamation and postage stamp rates.

Figure 8-1: Consolidation of Margin Related Deferral Accounts Upon Amalgamation[195]

Pre-Amalgamation			Amalgamation	
Region	*Account*		*Account*	
Mainland	CCRA	December 31, 2013	CCRA	January 1, 2014
Whistler	CCRA	December 31, 2013		
Mainland	MCRA	December 31, 2013	MCRA	January 1, 2014
Vancouver Island	GCVA	December 31, 2013		
Whistler	MCRA	December 31, 2013		
Fort Nelson	GCRA	December 31, 2013		
Mainland	RSAM	December 31, 2013	RSAM	January 1, 2014
Whistler	RSAM	December 31, 2013		
Fort Nelson	RSAM	December 31, 2013		

Table 8-3: Summary of Amalgamation/Postage Stamp Related Deferral Account Requests[196]

Type of Change	Account	Reference/Description
New Account	Amalgamation Costs Deferral Account	To capture the costs of amalgamation in a deferral account for future recovery from customers with amortization period TBD.
	Company Use and Unaccounted For Gas Cost Variance Account	Capture the variance in the company use and unaccounted for gas costs between the actual costs incurred and the forecast costs embedded in the FEI Amalco O&M expense, variances will be accumulated and amortized in rates over a one year period commencing in 2015.
	Amalgamation and Rate Design Application Costs	Non-rate base account, attracting interest to capture costs of this application, for future recovery from customers with amortization period TBD.
	Fort Nelson Phase-In Rate Rider Account	Non-rate base account, attracting AFUDC. Rider mechanism as discussed in Section 8.2.1.2.4.

[195] Mainland and Whistler gas supply commodity and midstream portfolios were amalgamated effective January 1, 2010 as approved by Commission Order No. G-35-09, however, for the individual entities revenue requirement purposes, a portion of the amalgamated portfolio was allocated to Whistler from the Mainland.

[196] Please note that this table is not an exhaustive list of all deferral accounts, rather it reflects changes required for amalgamation and postage stamp rates, please refer to Schedules 24 and 25 of Appendix J-1 for a complete list of FEI Amalco deferral accounts.

Type of Change	Account	Reference/Description
Consolidation of Margin Related Accounts	MCRA	Consolidation of the December 31, 2013 balances in the Vancouver Island GCVA and the Fort Nelson GCRA with the Whistler and Mainland MCRA balances into the FEI Amalco MCRA account effective January 1, 2014. The FEI Amalco MCRA to capture the variances between the forecast costs embedded in midstream rates and the actual incurred costs related to the gas supply midstream portfolio. No change to existing amortization period for this account.
Disposition	RSDA	December 31, 2013 balance in the non-rate base RSDA account returned to Mainland customers through a rate rider as discussed in Section 8.2.1.2.5.

Other Rate Base

With the exception of cash working capital, the other components of rate base (adjustment to thirteen month average, work in progress no AFUDC, other working capital, future income taxes regulatory assets and liabilities, and Lease In-Lease Out ("LILO") Benefit) reflect the summation of the stand-alone entities and do not require amalgamation adjustments. With respect to cash working capital, the Mainland net lead-lag days have been used to determine the cash working capital for FEI Amalco, resulting in an increase to rate base of approximately $0.7 million.

8.3 Return on Equity / Cost of Capital of the Amalgamated Entity

The utility cost of service includes the cost of capital. The capital structure and the ROE for the FEU are established by the Commission for use in the calculation of rates. The fair return standard, which must be applied in the determination of capital structure and ROE, ensures that regulated systems remain financially healthy and that investors are compensated appropriately and equitably for the risks they are undertaking.

In this section of the Application, the FEU discuss the present benchmark ROE, and how amalgamation and the adoption of common rates would impact the cost of capital and the fair return for the Amalgamated Entity, in comparison to the current benchmark utility, pre-amalgamation FEI.

The evidence in this section in support of the cost of capital and the fair return for the Amalgamated Entity was initially prepared for the FEU's November 2011 Amalgamation and Rate Design Phase "A" Application. Since that time, the BCUC has initiated the GCOC Proceeding. Among other things, the GCOC Proceeding will review (a) the setting of the appropriate cost of capital for a benchmark low-risk utility, (b) the possible return to an ROE Automatic Adjustment Mechanism ("AAM") for setting an ROE for the benchmark low risk utility, and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third-party debt.[197] It is the Companies' understanding that the GCOC Proceeding will establish a benchmark ROE based on a benchmark utility effective January 1, 2013 to December 31, 2013, for the initial transition year. This benchmark would apply to both FEI Amalco and the current stand-alone FEU. This determination will likely have implications for the risk premium for the Amalgamated Entity, which we expect will be addressed in a future application following the GCOC proceeding. As noted in Commission Order No. G-20-12, the GCOC Proceeding is not intended to set each utility's risk premium on the Benchmark ROE and the individual utilities would establish separate future proceedings to set risk premiums or multiple individual utilities could apply to set their premiums by establishing a multi-utility cost of capital proceeding.

In support of the rates sought in this Application, the FEU are addressing the cost of capital for FEI Amalco in comparison to the existing pre-amalgamation Benchmark. The FEU believe for the reasons outlined in this section, that it is reasonable to have a 12 basis point premium over the benchmark ROE, which is currently 9.5%, and a capital structure of 40% equity and 60% debt for FEI Amalco. Since the cost of capital for FEI Amalco will need to be updated following the outcome of the GCOC Proceeding and any subsequent proceeding relating to a risk premium for the Amalgamated Entity, the FEU have proposed rates on an interim basis only.

If the Commission does not wish to consider issues related to cost of capital and return on equity in this Application, in relation to either the Amalgamated Entity or FEVI and FEW, due to the GCOC Proceeding, the FEU's proposed ROE and capital structure is nonetheless a reasonable rate to approve on an interim basis. The FEU's proposal reflects the weighted average of the existing ROE of the FEU and the current capital structure of the FEU. The FEU's proposal therefore reflects the status quo and is reasonable to approve on an interim basis until the GCOC Proceeding is complete.

8.3.1 BACKGROUND

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 tied the utilities' rates of return on equity to the forecast yield on long-term Canada (30 years) bonds for the forthcoming year. This formula was commonly referred to as the Automatic Adjustment Mechanism.

On May 15, 2009 the FortisBC Energy Utilities applied to the BCUC to request:

1. That the Commission eliminate the use of AAM in the determination of the ROE;

5. A review and adjustment to the Benchmark ROE and FEI's equity thickness for rate-setting purposes; and

6. That the determined ROE for FEI be used in establishing the ROE for FEVI and FEW used for rate setting.

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[197] BCUC Order No. G-20-12

By Order No. G-158-09 dated December 16, 2009, the Commission agreed that the appropriate equity ratio for FEI is 40 percent and approved an ROE for FEI of 9.50 percent for rate setting purposes. The Commission decision also set the FEI ROE as the Benchmark in establishing the return on equity and set FEW and FEVI's allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 50 basis points for both Utilities.

As neither FEVI nor FEW had applied for a change to their capital structures in the 2009 ROE Application, the Commission confirmed their 40% common equity ratios, and directed those utilities to file evidence as to what equity component best reflects their respective long-term business risks, acknowledging that FEVI and FEW have greater long term business risks:

> *"…the evidence suggests that both TGVI and TGW have greater long-term business risk than TGI while possessing similar deferral mechanisms to enable them to earn their allowed ROEs in the short-term. The Commission Panel further notes Ms. McShane's testimony that both utilities require greater equity thickness than 40 percent".* [198]

Table 8-4 provides the current deemed capital structure and return on equity applicable to each utility:

Table 8-4: Existing BCUC Approved Capital Structure And Return On Equity

Utility/Region	Debt	Common Equity	Return on Equity
Mainland	60%	40%	9.50%
Vancouver Island			10.00%
Whistler			10.00%
Fort Nelson			9.50%

In their 2012-2013 RRA, the Companies committed to provide the following information as part of this Application:

1. Evidence with respect to the equity ratio for FEVI and FEW on stand-alone basis; and
2. Evidence on the impact of amalgamation on appropriate capital structure and ROE for the Amalgamated Utility, all else being equal.

The FEU stated:

> *"Under the Companies' proposal, in the Fall [RDA Phase A] application the Companies would provide:*
>
> - *Evidence with respect to the equity ratio for FEVI and FEW on stand-alone basis. (The evidence would be provided to meet the Commission's*

[198] British Columbia Utilities Commission, "In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure", December 16, 2009, page 76.

> *directive. It is currently expected that the Companies still would not seek at that time any change for the stand-alone FEVI and FEW capital structures, as that would be based on the assumption that amalgamation will not proceed).*
>
> - *Evidence on the impact of amalgamation on appropriate capital structure and ROE for the amalgamated utility, all else being equal. (Note that this would take the form of a change relative to the existing benchmark, and not a change to the benchmark itself. The current benchmark, based on the pre-amalgamation FEI as the benchmark low risk utility, can remain in place until the next comprehensive cost of capital proceeding)."*[199]

Through Order No. G-129-11, the Commission approved FEU's request to defer filing evidence with respect to the equity ratio for FEVI and FEW on a stand-alone basis:

> *"The Commission Panel approves FEU's request to defer the filing of evidence with respect to FEVI and FEW's equity component required by Directive No. 7 of Commission Order G-158-09, to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011."*

The evidence on the long term business risks and the expert opinion for the appropriate equity ratio for FEVI and FEW is provided as part of this Application in order to meet Commission Directive No. 3 of Order No. G-129-11. The evidence put forth in Appendices C-2 and C-3 establishes that both FEVI and FEW face higher long-term business risks than the benchmark utility. Thus, both should have a higher common equity component. The evidence and the expert opinion also suggest that an appropriate equity ratio for FEVI and FEW is 45%.

Within this Application, the Companies are not requesting that the Commission increase the stand-alone common equity components of the capital structures of FEVI and FEW at this time. The evidence has been provided as directed by the Commission in past orders noted above. If FEVI and FEW continue as standalone utilities, they will apply for changes to their equity component and risk premium following the GCOC proceeding, making reference to both the characteristics of the benchmark utility that will be determined in that proceeding and the relevant risk factors prevalent at that time. This approach is consistent with the preliminary scoping document in the GCOC Proceeding (Order no. G-20-12) which indicates that the individual utilities' risk premiums will be set in a separate future proceeding for that utility or in a future Multi-Utility Cost of Capital proceeding.

The following section discusses the opinion of Ms. Kathleen C. McShane, within the scope of the impact of amalgamation on cost of capital. A detailed summary of Ms. McShane's credentials is attached to her testimony in Appendix C-2.

[199] 2012-2013 RRA, page 314.

8.3.2 IMPACT OF AMALGAMATION ON CAPITAL STRUCTURE AND RETURN ON EQUITY

In the 2009 Return on Equity and Capital Structure proceeding, the following items were discussed and accepted as key drivers affecting the business risks of the benchmark utility, FEI.

1. BC Government policies on climate change and energy policies;
2. Aboriginal Rights Issues;
3. The Competitiveness of Natural Gas; and
    i. Competitive position of natural gas vs. electricity
    ii. Competition with alternative energy sources
4. Ability to Attach New Customers and Retain Customer Base At Risk
    i. Capture rates of natural gas vs. electricity
    ii. Declining trend in customer usage.

In the same proceeding the Commission recognized that FEW and FEVI face higher longer term risks than the benchmark utility:

> *"..the evidence suggests that both TGVI and TGW have greater long-term business risk than TGI while possessing similar deferral mechanisms to enable them to earn their allowed ROEs in the short-term. The Commission Panel further notes Ms. McShane's testimony that both utilities require greater equity thickness than 40 percent."*[200]

These additional risks, as outlined in the Business Risks Evidence filed as part of Appendix C-1 of this Application are the following:

- Both FEVI and FEW are relatively smaller utilities that cannot diversify their risks to the same extent as FEI, whose assets, geography and economic bases are less concentrated;
- Greater supply risk due to dependency on a single pipeline system that traverses rugged terrain and incorporates numerous stream crossings and, in the case of FEVI, a high pressure marine crossing; and
- FEVI faces the elimination of Royalty Revenues at the end of 2011 that have ranged from $17 to $43 million in recent years and cover approximately 15%-25% of the current cost of service.

Based on the business risks faced by FEI, FEVI and FEW as found in the 2009 Cost of Capital Decision, supported in the materials provided here and as part of Appendix C-4, Ms. McShane has provided an opinion on the impact of amalgamation on cost of capital and allowed return on equity. According to her testimony, while amalgamation results in diversification that reduces

[200] British Columbia Utilities Commission, Order No. G-158-09, "In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure", December 16, 2009, p. 76.

the risk facing FEVI and FEW on a stand-alone basis, on a portfolio basis, FEI Amalco will assume some of the FEVI and FEW long-term business risks, thus will face a higher risk than the benchmark utility, FEI. Hence the post amalgamation return on equity should be in the higher end of the 9.50%-9.62% range. She states:

> *"…At the lower end of the range, the post-amalgamation cost of capital for FEI is at least equal to FEI's cost of capital pre-amalgamation, since the folding in of the two smaller utilities does not lower FEI's cost of capital. The upper end of the range reflects the weighted average of the costs of capital of the three utilities on a stand-alone basis. As regards the return on equity, the allowed ROE for FEI is currently 9.50%; the allowed ROE for both FEVI and FEW is 10.0%. The weighted average ROE (based on the forecast 2013 rate bases of the three utilities) is 9.62%. The resulting range of ROEs for FEI post-amalgamation is approximately 9.5% to 9.6%... In principle, the transfer of certain of the FEVI's and FEW's utility-specific business risks to FEI, and the overall impact of rate harmonization on the competitive risks of FEI suggest that FEI's post-amalgamation cost of capital would be modestly higher than the cost of capital for the benchmark utility (i.e., FEI pre-amalgamation) and thus both the ROE and common equity ratio for FEI post-amalgamation should be toward the upper end of the range"*[201]*.*

This conclusion of credit neutrality is also highlighted by DBRS[202] in its September 2011 report:

> *"…At this time DBRS anticipates that the potential amalgamation and associated rate harmonization will likely be credit neutral to FEI provided that there are no material changes that will negatively affect its deemed capital structure, allowed ROE or fundamental low-risk business model."*[203]

In light of this evidence, the FEU submit that once the rate constructs are unified in 2014 it is appropriate for FEI Amalco to have an ROE slightly higher than the approved Benchmark, at 9.62%. A 12 basis point premium over the Benchmark ROE reflects the amalgamation of FEI with two entities that have greater associated business risks.

Ms. McShane's evidence supports that the FEW and FEVI stand-alone capital structure should have a greater equity component (at 45% equity); FEI Amalco is seeking to maintain the 40% equity 60% debt ratio on an amalgamated basis as the Companies recognize that amalgamation will mitigate certain business risks that are unique to stand alone FEVI and FEW and a 40% Common Equity ratio for FEI Amalco would set a reasonable capital structure.

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201 Appendix C-4, Kathleen C. McShane, "Opinion on Impact of Amalgamation on Cost of Capital for the FortisBC Energy Utilities", October 2011, p.12-13.

202 Dominion Bond Rating Service, or widely known as DBRS, is a globally recognized provider of credit rating opinions across a broad range of financial institutions, corporate entities, government bodies and various structured finance product groups in North America, Europe, Australasia and South America. Currently, DBRS rates more than 1,000 different companies and single-purpose vehicles that issue commercial paper, term debt and preferred shares in the global capital markets.

203 Appendix C-8, DBRS, *Private Rating Report: FortisBC Energy Inc.*, September 19, 2011.

In sum, subject to the outcome of the GCOC Proceeding, the Companies believe that it is appropriate for FEI Amalco to have a 12 basis point risk premium over the benchmark of 9.50%, ROE with a 40 percent equity ratio at the present time.

8.4 2014 Common rates for the Amalgamated Entity

As part of this Application, the Companies are seeking approval of interim common rates for FEI Amalco effective January 1, 2014 as set out in the Bill Impact Schedules attached as Appendix J-3. Please see the introduction to section 2 for a discussion of the FEU's rationale for proposing an interim 2014 rate.

A common rate for FEI Amalco customers consists of an identical basic, delivery, midstream and commodity charge for each rate class, regardless of where a customer resides. This rate structure ensures consistency and simplicity for all customers. This section discusses the impact of amalgamation and common rates for the FEU customer classes in detail. The FEU believe that the rate changes associated with moving to common rates are in all respects just and reasonable.

8.4.1 OVERVIEW OF RATE CHANGES BY CLASS

For comparative purposes, the tables below illustrate the difference between the basic, delivery, midstream and commodity charges, for the existing service areas versus the proposed charges for the Amalgamated Entity. The rate classes for Vancouver Island, Whistler and Fort Nelson have been mapped over into the appropriate Mainland rate class as discussed in Section 9. While the comparisons presented below are based on the 2013 rates, the impact of amalgamation, hence the difference between the stand-alone and amalgamated rates, would not be different in 2014.

The Mainland, Vancouver Island, Whistler and Fort Nelson rates in the tables are based on the proposed 2013 rates from the 2012-2013 RRA filed on May 4, 2011, the RRA Evidentiary Update submitted on September 12, 2011, and the forecast commodity and midstream costs for January 1, 2013. The Amalgamated Entity rates are based on the 2013 test year cost of service model for the Amalgamated Entity. Effective rate calculations are based on 90GJ, 250GJ and 2,490GJ of annual consumption for residential, small commercial and large commercial customers respectively and forecast January 1, 2013 commodity and midstream rates based on five-day average forward prices at November 1, 2, 3, 4, and 7, 2011 consistent with the natural gas forward pricing utilized in the 2011 Fourth Quarter Gas Cost reports. The rates presented below in Table 8-5, Table 8-6 and Table 8-7 exclude all riders and other fees.[204]

The existing Vancouver Island rate structure combines the delivery, midstream and commodity charge into one consolidated category called the energy charge. Fort Nelson also has a unique

[204] Please refer to Appendix J-6 for detailed bill impact summary tables showing both absolute and percentage changes.

rate structure with the basic charge including the first 2GJ of consumption and tiered delivery rates. It is therefore not possible to precisely compare each individual rate component. However, for the purposes of comparison the FEU is also providing proxy breakdown values for commodity, midstream and delivery components of FEVI, FEW and FEFN rates[205].

The tables show a decrease in the effective rates for typical customers in all three Vancouver Island rate classes as a result of adopting common rates. Similarly, Whistler customers also experience an overall decrease for each rate class presented resulting from common rates. Typical FEI Mainland and FEFN customers however will see increases to their annual bills. The comparison is presented for residential, small commercial and large commercial customers.

Table 8-5: Rate Schedule 1 (Residential) 2014 Effective Rates (based on 90GJ annual consumption) [206]

		FEI			Vancouver Island	Whistler	Fort Nelson
	FEI Amalco	*LM RS1*	*Inland RS1*	*Columbia RS1*	*RGS*	*SGS-R*	*GSR 1.1b*
Fixed Charge							
Basic Daily Charge	$ 0.389	$ 0.389	$ 0.389	$ 0.389	$ 0.345	$ 0.246	$ 0.594
Variable Charge							
Delivery	$ 4.361	$ 3.881	$ 3.881	$ 3.881	$ 7.872	$ 11.686	$ 2.443
Midstream	$ 1.384	$ 1.402	$ 1.367	$ 1.411	$ 1.384	$ 1.107	$ 0.276
Commodity	$ 4.108	$ 3.997	$ 3.997	$ 3.997	$ 5.069	$ 3.997	$ 3.920
Energy					$ 14.325		
Effective Total	$ 11.432	$ 10.859	$ 10.824	$ 10.868	$ 15.725	$ 17.790	$ 7.280

* Vancouver Island delivery, midstream & commodity charges are proxy breakdowns adding up to the energy charge.
** Fort Nelson midstream & commodity charges are proxy values adding up to the total cost of gas.
*** Fort Nelson Delivery Rate reflects the first tier delivery charge, i.e. first 28GJ of consumption/month after the initial 2GJ included in the basic charge.

Table 8-6: Rate Schedule 2 (Small Commercial) 2014 Effective Rates (based on 250GJ annual consumption) [207]

		FEI			Vancouver Island				Whistler		Fort Nelson
	FEI Amalco	*LM RS2*	*Inland RS2*	*Columbia RS2*	*AGS*	*SCS1*	*SCS2*	*LCS1*	*SGS-C*	*LGS1*	*GSR 2.1*
Fixed Charge											
Basic Daily Charge	$ 0.816	$ 0.816	$ 0.816	$ 0.816	$ 1.314	$ 0.310	$ 1.102	$ 2.004	$ 0.246	$ 0.246	$ 1.207
Variable Charge											
Delivery	$ 3.499	$ 3.170	$ 3.170	$ 3.170	$ 5.920	$ 10.487	$ 10.002	$ 6.900	$ 11.686	$ 11.686	$ 2.747
Midstream	$ 1.316	$ 1.389	$ 1.354	$ 1.397	$ 1.384	$ 1.384	$ 1.384	$ 1.384	$ 1.107	$ 1.107	$ 0.276
Commodity	$ 4.108	$ 3.997	$ 3.997	$ 3.997	$ 5.069	$ 5.069	$ 5.069	$ 5.069	$ 3.997	$ 3.997	$ 3.920
Energy					$ 12.373	$ 16.940	$ 16.455	$13.353			
Effective Total	$ 10.115	$ 9.748	$ 9.713	$ 9.756	$ 14.293	$ 17.394	$ 18.064	$16.281	$ 17.150	$ 17.150	$ 8.039

* Vancouver Island delivery, midstream & commodity charges are proxy breakdowns adding up to the energy charge.
** Fort Nelson midstream & commodity charges are proxy values adding up to the total cost of gas.
*** Fort Nelson Delivery Rate reflects the first tier delivery charge, i.e. first 28GJ of consumption/month after the initial 2GJ included in the basic charge.

205 Please see Appendix J-7 for the proxy cost of gas calculations.
206 The effective rates calculations do not include riders or fees. Please refer to Appendix J-3, Tabs 1.1-1.4 for related bill impact schedules.
207 Ibid.

Table 8-7: Rate Schedule 3 (Large Commercial) 2014 Effective Rates (based on 2,490GJ annual consumption)[208]

		FEI			Vancouver Island			Whistler		Fort Nelson	
	FEI Amalco	*LM RS2*	*Inland RS2*	*Columbia RS2*	*AGS*	*LCS2*	*LCS3*	*LGS2*	*LGS3*	*GSR 2.1*	*GSR 2.2*
Fixed Charge											
Basic Daily Charge	$ 4.354	$ 4.354	$ 4.354	$ 4.354	$ 1.314	$ 3.214	$ 6.6205	$ 0.246	$ 0.246	$ 1.207	$ 1.207
Variable Charge											
Delivery	$ 2.954	$ 2.669	$ 2.669	$ 2.669	$ 5.920	$ 5.858	$ 5.562	$ 11.686	$ 11.686	$ 2.747	$ 2.747
Midstream	$ 1.055	$ 1.107	$ 1.078	$ 1.119	$ 1.384	$ 1.384	$ 1.384	$ 1.107	$ 1.107	$ 0.276	$ 0.276
Commodity	$ 4.108	$ 3.997	$ 3.997	$ 3.997	$ 5.069	$ 5.069	$ 5.069	$ 3.997	$ 3.997	$ 3.920	$ 3.920
Energy					$ 12.373	$ 12.311	$ 12.015				
Effective Total	$ 8.756	$ 8.412	$ 8.383	$ 8.424	$ 12.566	$ 12.782	$ 12.986	$ 16.826	$ 16.826	$ 7.053	$ 7.053

* Vancouver Island delivery, midstream & commodity charges are proxy breakdowns adding up to the energy charge.
** Fort Nelson midstream & commodity charges are proxy values adding up to the total cost of gas.
*** Fort Nelson Delivery Rate reflects the first tier delivery charge, i.e. first 28GJ of consumption/month after the initial 2GJ included in the basic charge.

Without a phase-in approach, the Fort Nelson region would see the largest adverse impact on rates under an amalgamated rate structure. The FEU recognize the rate increase Fort Nelson residents would face as a result of amalgamation, and have proposed a strategy to mitigate the effects of common rates for all Fort Nelson customers. The strategy is to phase-in the total rate increase over a fifteen year period with any impact delayed until year six, as discussed in the following section.

8.4.1.1 Fort Nelson Phase-In Approach

In order to mitigate the significant one-time rate increase to Fort Nelson customers, the FEU propose that FEI Amalco phase in the total amalgamation/postage stamp-related rate increase over 15 years. As discussed in Section 10, in developing this implementation approach, the FEU has discussed various options with the representatives from the region of Fort Nelson.

While the NRRC representing the Northern Rockies Regional Municipality and service area of Fort Nelson is not supportive of the FEU's common rates proposal, the NRRC was presented with two rate mitigation options and voted in favour of phasing-in the total rate increase over a 15 year period with any impact delayed until year six. This option was voted and approved as the preferred option during the NRRC meeting on September 20th, 2011. The FEU agreed to propose this approach for Fort Nelson customers within this Application.

According to this approach:

- In the first five years of the phase-in, Fort Nelson customers will be shielded from the initial common rate related increase but will continue to be subject to rate increases resulting from FEI Amalco revenue requirement changes as well as any changes to the commodity and/or midstream rates.
- After the initial five year period in 2019, as described below, a portion of the postage stamp and amalgamation-related cost of service increase will be flowed through, with an approximate 3.5%-4.5% annual burner-tip bill impact for typical residential customers,

208 Ibid.

with the amount within this range depending on the year.[209] This annual increase will continue through to 2027 and in 2028 (i.e., Year 15), Fort Nelson customers reach rate parity with the Amalgamated Entity.

The shortfall arising from the phase-in of the Fort Nelson rate increases for the fifteen year period will be met through a portion of the RSDA funds as described in the following section.

The phase-in will be applied as described below, and an appendix (Appendix J-1 Schedule 34) has been provided with a summary of the annual phase-in balances.

No Amalgamation/Postage Stamp-Related Rate Impact from 2014 to 2018:

For the years 2014-2018, instead of absorbing the full impact of amalgamation, Fort Nelson customers will only experience rate increases arising from the approved FEI Amalco revenue requirement changes and/or changes to commodity and midstream rates or approved changes to return on equity or capital structure for the Amalgamated Entity.

To arrive at a zero net bill impact arising from amalgamation and common rates for a typical Fort Nelson customer in 2014, the FEU propose to use a negative delivery rate rider, called the Fort Nelson Phase-in Rider. Using current projections of 2013 volumes and the amalgamated cost of service as described in Section 8.1 above, the 2014 phase-in rider is projected to be ($3.868)/GJ for residential customers within the Fort Nelson service area (Table 8-8 below). The total shortage arising from this phase-in approach is projected to be $1.99 million in 2014 based on 2013 test year volumes, summing up to a projected $18.9 million over the full 15 year period as shown in Table 8-9 below.

The Companies are proposing to allocate funds from the December 31, 2013 RSDA balance to the Fort Nelson Phase-In Rate Rider deferral account to cover the total shortfall (projected to be $18.9 million) arising from the phase-in of the Fort Nelson common rates.[210]

Table 8-8 below provides an overview of the forecast rider amounts for residential, small commercial and large commercial customers using the 2013 test year volumes. The actual Phase-in Rider in place for 2014 will be determined in 2013 once the forecast volumes for 2014 are available.

Table 8-8: Estimated Fort Nelson (Amalgamation Adjustment) Phase-in Rider For 2014[211]

	FEFN
Residential Phase-in Rider	($3.868)
Small Commercial Phase-in Rider	($2.082)
Large Commercial Phase-in Rider	($3.110)

209 Excluding adjustments to account for variances in actual and forecast volumes to ensure that there is no carry over balance.
210 Appendix J-1, Schedule 33, Line 4.
211 Appendix J-1, Schedule 34. Please note that Table 8-9 provides the estimated Fort Nelson Phase-in Riders using the 2013 forecast volumes as the basis. The actual Phase-in Rider for 2014 will be determined in 2013, once the forecast volumes for 2014 are available.

The 2015 to 2018 (inclusive) Fort Nelson phase-in rate riders will be adjusted to account for variances in actual and forecast volumes from the prior year and changes in volume forecasts for the upcoming year.

Amalgamation/Postage Stamp-Related Impacts Phased-in From 2019 to 2028:

Starting in 2019, the amalgamation-related rate increases will begin to be flowed through to Fort Nelson customers for the following ten years, ending in 2028 when Fort Nelson customers will reach delivery rate parity with the Amalgamated Entity. This phase-in will be accomplished through an annual decrease of one-tenth in the rider amounts returned to Fort Nelson customers.

The annual rate riders will also be adjusted to account for variances in actual and forecast volumes from the prior year and changes in volume forecasts for the upcoming year.

Appendix J-1, Schedule 34 demonstrates the schedule of the phase in of the Fort Nelson common rates and the calculation of the projected total amount to be allocated from the RSDA to the Fort Nelson Phase in Rate Rider deferral account as shown in Table 8-9.

Table 8-9: Fort Nelson Phase-In Financed by RSDA

Fort Nelson Amalgamation Adjustment Rider Deferral Account Continuity
$ Thousands

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Opening Balance	-	(16,897)	(14,909)	(12,921)	(10,933)	(8,945)	(7,156)	(5,566)	(4,175)	(2,982)	(1,988)	(1,193)	(596)	(199)
RSDA Allocation	(18,885)	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider Recoveries[1]	1,988	1,988	1,988	1,988	1,988	1,789	1,590	1,392	1,193	994	795	596	398	199
Closing Balance	(16,897)	(14,909)	(12,921)	(10,933)	(8,945)	(7,156)	(5,566)	(4,175)	(2,982)	(1,988)	(1,193)	(596)	(199)	(0)

[1] Rider recoveries are shown as positive reflecting the drawn down of the credit balance of the account. The rate riders applicable to Fort Nelson customers will be negative to accomplish this.

A Fort Nelson customer will have the same basic charge, commodity, midstream and delivery rates as all other customers in the same rate class of FEI Amalco, with the exception of the phase-in rider (FEI Mainland customers will also have an RSDA rider that Fort Nelson customers will not receive). This highlights the consolidation of the FEU and provides consistency with the rest of FEI Amalco.

The phase-in rider will spread the impact of the one-time rate increase for Fort Nelson customers over 15 years to moderate the impact of the transition to common rates. When the time value of money is considered, on an annual bill basis Fort Nelson Residential customers will incur savings over the 15 years of approximately $4 million or 26% (all else equal) under the phase-in approach as compared to adopting amalgamated rates in 2014.[212] During this period, Fort Nelson customers will still be subject to changes in delivery rates arising from FEI Amalco revenue requirements, as well as any changes in commodity and midstream rates. Despite the

[212] Savings are based on the present value after tax weighted average cost of capital of the Fort Nelson Residential annual bill over the 15 year term Phase-In approach as compared to the present value of the Residential annual bill over the same period with the amalgamated rates adopted in 2014.

rate increases, the FEU believe Fort Nelson customers will benefit from common rates for the reasons discussed earlier in Section 6.

8.4.1.2 FEI - RSDA Amortization

Application of the remaining December 31, 2013 RSDA surplus (actual balance less the amount allocated to Fort Nelson) to FEI customers will help to mitigate the impact of amalgamation. For instance, based on the current projected December 31, 2013 RSDA balance of $90.3 million (before tax) and after deducting the $18.9 FEFN allocation as discussed above, returning the remaining RSDA balance of approximately $71.4 million to FEI Mainland non-bypass customers over three years would mitigate the impact of amalgamation for those customers such that the full impact of this one-time increase to the annual bill will occur only after the RSDA balance is exhausted at the end of this three year period. For example, for typical Lower Mainland residential customers, the impact of amalgamation and common rates, after including the projected remaining December 31, 2013 RSDA surplus of $71.4 million (before tax) being distributed to customers, will result in reducing the annual bill impact from 5.3% percent to a 3.3% percent increase based on 2013 test year numbers.

8.4.1.3 Using the RSDA to Mitigate the Impact on FEI Customers

The FEU believe that it is appropriate to return the remaining balance in the RSDA to FEI Mainland customers upon amalgamation through the RSDA Rider. The FEU's reasons for proposing this approach are as follows:

1. The rationale for accumulating the balance in the RSDA as justified in FEVI's 2009 Rate Design Application was primarily to help transition FEVI's customers to the higher rate that would result after the loss of Royalty Revenues. Under amalgamation, FEVI will see no rate increase; in fact as shown below in Section 8.4.2, the FEVI 2013 rates would be lower than current rates. Under amalgamation, the impact of the loss of Royalty Revenues would now be shared by one large entity. Therefore, the FEU believe that it is appropriate to return the RSDA to FEI Mainland customers as those customers will incur an increase to their rates as a result of amalgamating with FEVI and FEW customers. The benefits received from adoption of common rates for FEVI equal the benefits they would have derived from the RSDA within approximately 1.5 years following amalgamation.213
2. This allocation methodology meets the overall principles of the rate design, namely, fairness, customer impact, stability and ease of understandability, administration and rate continuity as discussed in Section 9. The FEU believe the proposed RSDA allocation methodology is fair as it helps to offset the increase in FEI Mainland customer rates resulting from amalgamation.

Based on the current forecasted balance at the end of 2013 ($90.3 million[214] before tax) and after deducting the FEFN Allocation ($18.9 million), the Companies are proposing to return the

[213] Appendix D-2
[214] Appendix J-1, Schedule 33

RSDA surplus to FEI Mainland customers to mitigate rate impacts associated with amalgamation and common rates. As discussed below, the balance of the RSDA surplus will be returned to Mainland customers through a delivery rate rider over a three year period following amalgamation, thereby mitigating the impact of amalgamation for that three year period.

Mainland RSDA Allocation Options

Three RSDA allocation options were explored to help transition FEI Mainland customers to amalgamated rates. All three options use a delivery rate rider to stream the allocation of the RSDA to Mainland customers. The results of the various options and their impacts on a typical FEI Mainland residential customer's annual bill are summarized in Table 8-10 below, followed by a detailed explanation of each of the options. The table highlights the cumulative annual percentage change to a typical customer's annual bill (as compared to 2013 amalgamated rates with no RSDA rider) over a period of six years.

Table 8-10: Forecast Cumulative Annual Bill Impact of FEI Mainland RSDA Allocation Options[215]

RSDA Allocation Analysis	2014	2015	2016	2017	2018	2019
FEI - Full RSDA Allocation	0.3%	4.2%	5.3%	5.3%	5.3%	5.3%
FEI - 3 Year RSDA Allocation	3.3%	3.3%	3.3%	5.3%	5.3%	5.3%
FEI - 5 Year RSDA Allocation	4.1%	4.1%	4.1%	4.1%	4.1%	5.3%

*2013 Amalgamated Rates Used as Benchmark for Annual Bill Impacts

Mainland – Full RSDA Allocation

This option uses the RSDA to offset the entire Mainland delivery margin revenue deficiency of $59.2 million that occurs as a result of amalgamation.[216] To arrive at the delivery rate rider applicable to non-bypass Mainland customers in this scenario, the December 31, 2013 RSDA of $90.3 million is allocated based on each rate schedule's contribution to the delivery margin deficiency and then divided by the applicable forecast Mainland volume for 2013.[217] As shown in the table above, the impact to a typical customer's bill in 2014 is projected to be an increase of 0.3 per cent, thus this option is expected to fully offset the delivery margin impact of amalgamation to FEI customers in 2014.

Following 2014, any remaining balance in the RSDA would be allocated using the same methodology described above. It is anticipated that the RSDA would be fully distributed within 2015 resulting in an increase to the annual bill of a typical Residential Lower Mainland customer of 4.2 percent in 2015. That is, of the December 31, 2013 forecast RSDA balance of $90.3 million allocated to Mainland[218], $59.2 million will have been distributed to FEI Mainland customers in 2014, which results in a remaining balance of approximately $31.1 million available for rate mitigation in 2015. Thus, in 2015 the RSDA balance available does not offset

215 Lower Mainland Residential (Rate 1) customer consuming 95 GJs per year. Please see Appendix I-9
216 Appendix J-2, Schedule 1, Line 12
217 Appendix J-2, Schedule 8
218 $90.3 million - $18.9 million allocated to Fort Nelson = $71.4 million allocated to FEI.

the entire delivery margin revenue deficiency of $59.2 million. It is expected that FEI Mainland customers will move to fully amalgamated rates in 2016 under this scenario.

Although this option is forecast to mitigate the impact of amalgamation over a two year period, it results in a disproportionate change in rates. Furthermore, because the balance in the RSDA is subject to fluctuation, it could result in an unknown period of phase in; depending on the actual December 31, 2013 RSDA balance, this approach may not fully offset the impact in 2014 and there may not be a balance available for 2015 rates. A multi-year phase in proposal may address these concerns by providing a smoother transition to amalgamated rates.

Mainland – 3 Year RSDA Allocation

Under this option, the December 31, 2013 RSDA balance would be amortized equally over three years to all non-bypass FEI Mainland customers. To arrive at the delivery rate rider applicable in this scenario, the RSDA is allocated based on each rate schedule's contribution to delivery margin and then divided by the applicable forecast volume.

A multi-year phase in will not only prolong the length of time that Mainland customers will benefit from the RSDA, but it will also eliminate the fluctuation in the annual bill that results from fully allocating the RSDA in 2014. Returning the RSDA in 3 equal annual installments is forecast to limit delivery rate annual bill increases from amalgamation to 3.3 per cent in 2014. There will be no further increases resulting from amalgamation in 2015 and 2016. In 2017, rates are forecast to increase a further 2.0 per cent, for a total increase of 5.3 per cent. With the expiration of the rate rider in 2016, FEI Mainland customers will have fully transitioned to amalgamated rates in 2017.

As with the full phase in option, the amount of the rate rider is contingent on the actual December 31, 2013 balance in the RSDA; however, using a three year phase in period will extend the amount of time that customers receive the benefit of the RSDA and provide certainty with respect to when FEI Mainland customers will experience the full impact of amalgamated rates.

Mainland – 5 Year RSDA Allocation

A five year phase in provides the same benefits as the three year phase in, and extends the benefits of rate mitigation by an additional two years. The basis for this option is to return the RSDA to FEI Mainland customers evenly over a five year period. The impact to annual bills under this allocation methodology is a projected increase of 4.1 per cent in 2014. There would be no additional amalgamation-related increases in rates from 2015 to 2018. In 2019, rates are projected to increase a further 1.2 per cent, for a total increase of 5.3 per cent. Under this scenario, FEI Mainland customers will fully transition to amalgamated rates in 2019.

Customers benefit by having a longer transition period to fully amalgamated rates, effectively delaying the full impact of amalgamated rates. Although this option extends the benefits of the RSDA over a longer time period, it also results in a higher initial rate impact in 2014 than under the three year phase in scenario.

After analysis of the results, the FEU propose to return the RSDA to Mainland customers over a period of three years. FEU believes that this approach achieves the best balance amongst the customer impact, stability and ease of understandability, administration and rate continuity rate design principles.

8.4.2 BILL IMPACT ANALYSIS

Common rates will have varying impacts on customers, based on their current service location, and the amount of commodity consumed. Using the 2013 test year numbers, and in the absence of the mitigation strategies discussed above, typical FEI Mainland and FEFN customers would experience increases in their annual bills in 2014 due to amalgamation. With the allocation of the RSDA balance however, the overall impact of amalgamation for FEI Mainland customers will be spread over three years, while typical Fort Nelson residential customers will not experience any amalgamation related rate increases in 2014. Typical FEVI and FEW customers will both experience large decreases in their bills.

The bill impact schedules presented in the following sections highlight the projected changes in annual bills pre- and post-amalgamation for customers in the Mainland, Vancouver Island, Fort Nelson and Whistler. The rate schedules discussed are for residential, small commercial and large commercial customers. Please refer to Appendix J-3 for a comprehensive set of bill impact schedules for all rate classes.

8.4.2.1 Residential

Rate Schedule 1, or Residential Service, includes service to single family residences, separately metered single family townhouses, row-houses and apartments. Most residential customers use natural gas for space and water heating, fireplaces and to a lesser extent cooking and clothes drying. Usage varies depending on the types of appliances installed but typically ranges from about 60 GJ to 180 GJ per year per household. Residential rates include a fixed daily basic charge and gas cost recovery (midstream and commodity) and delivery charges that vary with the amount of gas consumed.

The following table illustrates the estimated 2014 annual bill impacts using the 2013 test year numbers for all service areas under the existing rate structure and under the proposed amalgamated rate structure, both with and without the impacts of the RSDA rider and Fort Nelson Phase-in rider. Please note that the numbers provided are based on typical annual usage and will vary with consumption.

Table 8-11: Estimated Annual Bill Impact Comparison For Typical Residential Customers[219]

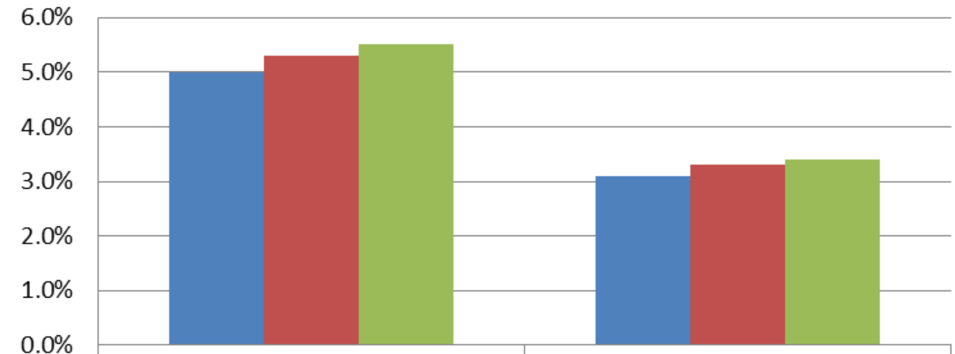
Service Area	Without RSDA and FEFN Phase-In for 2014				With RSDA and FEFN Phase In for 2014			
	Stand-Alone	Amalgamated	$ Impact	% Impact	Stand-Alone	Amalgamated	$ Impact	% Impact
FEI								
Lower Mainland (95 GJ/year)	$ 1,028	$ 1,082	$ 54	5.3%	$ 1,028	$ 1,062	$ 34	3.3%
Inland (75 GJ/year)	$ 839	$ 884	$ 45	5.4%	$ 839	$ 868	$ 29	3.5%
Columbia (80 GJ/year)	$ 889	$ 934	$ 45	5.0%	$ 889	$ 916	$ 28	3.1%
FEVI								
RGS (59 GJ/year)	$ 965	$ 722	$ (244)	-25.2%	$ 965	$ 722	$ (244)	-25.2%
FEW								
SGS Residential (90 GJ/year)	$ 1,654	$ 1,032	$ (621)	-37.6%	$ 1,654	$ 1,032	$ (621)	-37.6%
FEFN								
RS 1.1b (140 GJ/year)	$ 986	$ 1,527	$ 542	54.9%	$ 986	$ 986	$ -	0.0%

A typical residential Lower Mainland customer will experience an estimated 5.3% increase in his or her annual bill as a result of amalgamation and adoption of common rates, however due to the RSDA allocation this increase will be partially mitigated for three years. As a result, an average residential customer in the Lower Mainland will experience an approximate 3.3% increase to their annual bill in 2014 resulting from amalgamation. Typical residential FEVI and FEW customers will see decreases in their annual bills estimated at 25.2% and 37.6% respectively. Typical residential Fort Nelson customers, who have enjoyed comparatively low rates relative to the rest of the Province, will only experience an increase in their annual bill associated with the postage stamping starting in 2019. After 2018 the postage stamp-related increase will be gradually phased in over 10 years.

To provide a representative analysis of the customers in each region, 2014 bill impacts were calculated based on low, typical and high usage customers using 2013 test year numbers. The following figure shows the annual bill impacts for a low, typical and high usage residential customer in the Lower Mainland, both with and without the RSDA rider. The low usage analysis is based on an average usage of 67 GJ, the typical user is based on an average usage of 95 GJ and the high usage analysis is based on an average usage of 122 GJ.

[219] The annual bills are calculated based on the typical annual usage for each service territory, as shown in Bill Impact Schedules in Appendices J-3 and J-4, Tabs 1-4.

Figure 8-2: Lower Mainland Estimated Residential Bill Impacts For Low/Typical/High Usage Customers with 2013 Test Year Numbers



	Bill Impact Exclusive of RSDA	Bill Impact Inclusive of RSDA
FEI Low (67GJ)	5.0%	3.1%
FEI Typical (95GJ)	5.3%	3.3%
FEI High (122GJ)	5.5%	3.4%

As illustrated in Figure 8-2 above, representative residential Lower Mainland customers with low, typical and high usage patterns will see partially mitigated increases in their annual bills in 2014 due to the RSDA. The magnitude of increase will be approximately 3.3%.

8.4.2.2 Small Commercial

Rate Schedule 2, or Small Commercial Service, applies to commercial, institutional or light industrial applications of less than 2,000 GJ per year which generally includes service to small businesses, small apartment buildings and restaurants. Similar to the rate structure for residential service, commercial rates include a fixed daily basic charge and gas cost recovery (midstream and commodity) and delivery charges that vary with the amount of gas consumed.

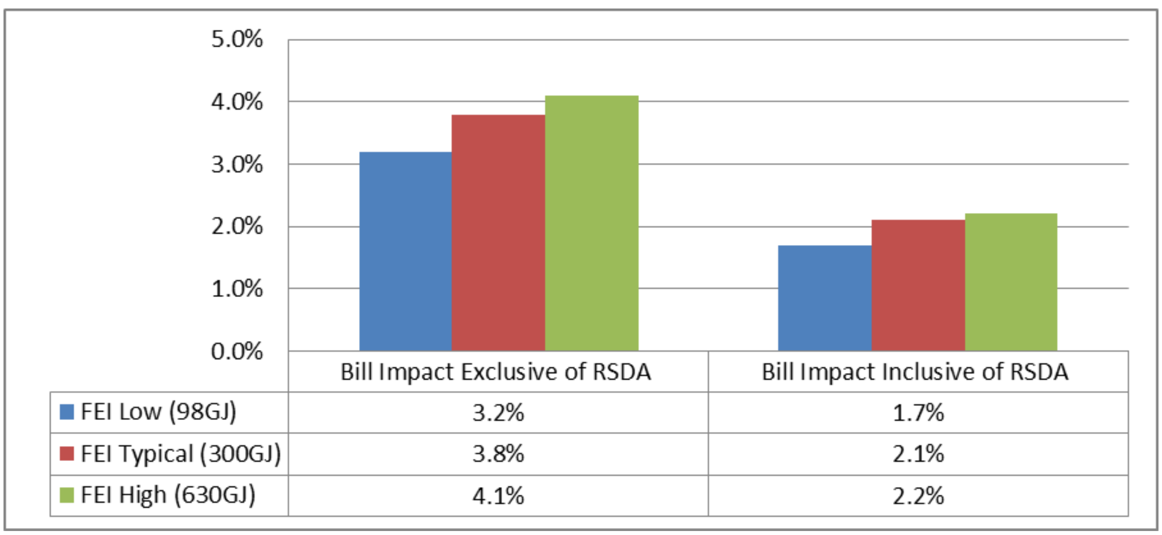
The following table illustrates the 2014 estimated annual bill impacts using the 2013 test year numbers for all service areas under the existing rate structure and under the proposed amalgamated rate structure, both with and without the impacts of the RSDA rider and Fort Nelson Phase-in rider.

Table 8-12: 2013 Estimated Annual Bill Impact Comparison for Typical Small Commercial Customers[220]

Service Area	Without RSDA and FEFN Phase-In				With RSDA and FEFN Phase In			
	Stand-Alone	Amalgamated	$ Impact	% Impact	Stand-Alone	Amalgamated	$ Impact	% Impact
FEI								
Lower Mainland (300 GJ/year)	$ 2,878	$ 2,987	$ 109	3.8%	$ 2,878	$ 2,939	$ 60	2.1%
Inland (250 GJ/year)	$ 2,440	$ 2,539	$ 99	4.1%	$ 2,440	$ 2,499	$ 59	2.4%
Columbia (320 GJ/year)	$ 3,053	$ 3,166	$ 113	3.7%	$ 3,053	$ 3,115	$ 62	2.0%
FEVI								
AGS (780 GJ/year)	$ 10,131	$ 7,289	$ (2,842)	-28.1%	$ 10,131	$ 7,289	$ (2,842)	-28.1%
SCS1 (80 GJ/year)	$ 1,474	$ 1,018	$ (456)	-30.9%	$ 1,474	$ 1,018	$ (456)	-30.9%
SCS2 (313) GJ/year)	$ 5,546	$ 3,100	$ (2,446)	-44.1%	$ 5,546	$ 3,100	$ (2,446)	-44.1%
LCS1 (929 GJ/year)	$ 13,148	$ 8,632	$ (4,516)	-34.3%	$ 13,148	$ 8,632	$ (4,516)	-34.3%
FEW								
SGS Commercial (260 GJ/year)	$ 4,607	$ 2,628	$ (1,979)	-43.0%	$ 4,607	$ 2,628	$ (1,979)	-43.0%
LGS1 (1060 GJ/year)	$ 17,408	$ 9,799	$ (7,609)	-43.7%	$ 17,408	$ 9,799	$ (7,609)	-43.7%
FEFN								
RS 2.1 (460 GJ/year)	$ 3,463	$ 4,421	$ 958	27.7%	$ 3,463	$ 3,463	$ 0	0.0%

To provide a representative analysis of the customers in each region, 2014 bill impacts were calculated based on low, typical and high usage customers using the 2013 test year numbers. The following graph shows the 2014 bill impacts for a low, typical and high usage customer in the Lower Mainland, including the impact of the RSDA rider. The low usage analysis is based on an average usage of 98 GJ, the typical user is based on an average usage of 300 GJ and the high usage analysis is based on an average usage of 630 GJ.

Figure 8-3: 2013 Lower Mainland Estimated Small Commercial Bill Impacts for Low/Typical/High Usage Customers



Similar to residential customers, representative small commercial Lower Mainland customers with low, typical and high usage patterns will also experience partially mitigated increases in their annual bills in 2014 due to the RSDA, in the range of 2.0%.

[220] The annual bills are calculated based on the typical annual usage for each service territory, as shown in Bill Impact Schedules in Appendices J-3 and KJ4, Tabs 1-4.

8.4.2.3 Large Commercial

Rate Schedule 3, or Large Commercial Service, is restricted to customers using more than 2,000 GJ per year. Customers served on this rate schedule include larger commercial, institutional and small industrial operations. Annual usage can vary from 2,000 to 10,000 GJ per year.

The rates for this schedule feature a higher daily basic charge and lower variable gas cost recovery (midstream and commodity) and delivery charges than the small commercial rates.

The following table illustrates the estimated 2014 annual bill impacts using the 2013 test year numbers for all service areas under the existing rate structure and under the proposed amalgamated rate structure, both with and without the impacts of the RSDA rider and Fort Nelson Phase-in rider:

Table 8-13: 2013 Estimated Annual Bill Impact Comparison for Typical Large Commercial Customers[221],[222]

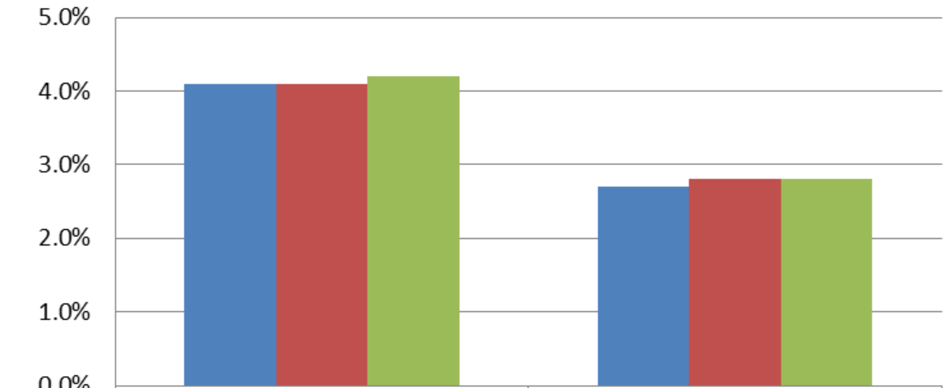
Service Area	*Without RSDA and FEFN Phase-In*				*With RSDA and FEFN Phase In*			
	Stand-Alone	Amalgamated	$ Impact	% Impact	Stand-Alone	Amalgamated	$ Impact	% Impact
FEI								
Lower Mainland (2800 GJ/year)	$ 23,433	$ 24,432	$ 998	4.3%	$ 23,433	$ 24,085	$ 652	2.8%
Inland (2600 GJ/year)	$ 21,797	$ 22,800	$ 1,003	4.6%	$ 21,797	$ 22,478	$ 680	3.1%
Columbia (3300 GJ/year)	$ 27,373	$ 28,510	$ 1,137	4.2%	$ 27,373	$ 28,101	$ 728	2.7%
FEVI								
AGS (3,990 GJ/year)	$ 49,848	$ 34,139	$ (15,709)	-31.5%	$ 49,848	$ 34,139	$ (15,709)	-31.5%
LCS2 (2,362 GJ/year)	$ 30,251	$ 20,858	$ (9,394)	-31.1%	$ 30,251	$ 20,858	$ (9,394)	-31.1%
LCS3 (17,694 GJ/year)	$ 215,012	$ 145,931	$ (69,081)	-32.1%	$ 215,012	$ 145,931	$ (69,081)	-32.1%
FEW								
LGS2 (2810 GJ/year)	$ 48,911	$ 24,400	$ (24,511)	-50.1%	$ 48,911	$ 24,400	$ (24,511)	-50.1%
FEFN								
GSR 2.1 (2624 GJ/year)	$ 18,464	$ 22,996	$ 4,532	24.5%	$ 18,464	$ 14,836	$ (3,627)	-19.6%
GSR 2.2 (3100 GJ/year)	$ 21,763	$ 26,879	$ 5,115	23.5%	$ 21,763	$ 17,239	$ (4,524)	-20.8%

To provide a representative analysis of the customers in each region, 2014 bill impacts were calculated based on low, typical and high usage customers. The following graph shows the 2014 annual bill impacts for a low, typical and high usage customer in the Lower Mainland, including the impact of the RSDA rider, using 2013 test year numbers. The low usage analysis is based on an average usage of 2,300 GJ, the typical user is based on an average usage of 2,800 GJ and the high usage analysis is based on an average usage of 4,100 GJ.

221 The annual bills are calculated based on the typical annual usage for each service territory, as shown in Bill Impact Schedules in Appendices J-3 and J-4, Tabs 1-4.

222 An average rate rider is calculated and applied to Fort Nelson GSR 2.1, GSR 2.2 and Rate 25 customers moving to FEI Rate Schedule 3, resulting in varying bill impact changes among these customer classes.

Figure 8-4: 2013 Lower Mainland Estimated Large Commercial Bill Impacts for Low/Typical/High Usage Customers



	Bill Impact Exclusive of RSDA	Bill Impact Inclusive of RSDA
FEI Low (2300GJ)	4.1%	2.7%
FEI Typical (2800GJ)	4.1%	2.8%
FEI High (4100GJ)	4.2%	2.8%

Large commercial Lower Mainland customers with low, typical and high usage patterns will experience an approximately 3% increase in their 2014 annual bills with the RSDA mitigation.

In summary, the FEU believe that the proposed rate changes associated with amalgamation and the subsequent move to uniform basic, delivery, midstream and commodity charges for each rate class, regardless of the historical service area, are just and reasonable.

9 RATE DESIGN

9.1 Introduction

In this section the FEU will discuss the proposed rate design for the Amalgamated Entity. As discussed below, the rate design methodology currently in place for FEI represents a fair basis upon which to establish common rates for the Amalgamated Entity.

The FEU retained EES Consulting, a multidisciplinary management consulting firm with particular expertise in rate design methodology and COSA Modeling, to validate this rate design approach. The Commission had previously retained EES Consulting to act as an independent advisor on similar rate design issues, and EES Consulting is familiar with the FEU's business. EES Consulting has confirmed that, in its expert opinion, the COSA methodology and model employed for the rate design are consistent with historical and industry practices and the results and conclusions derived are appropriate for the Amalgamated Entity.[223]

This section is organized as follows:

- Section 9.2 identifies which customers are, and are not, affected by the rate design;
- Section 9.3 discusses FEI's approved rate design methodologies, which provide the basis for the rate design for the Amalgamated Entity;
- Section 9.4 explains how the FEU have mapped the FEVI, FEW and FEFN customers into the FEI rate classes;
- Section 9.5 addresses how the rate design principles used in past rate design proceedings and previously accepted by the Commission remain appropriate for the Amalgamated Entity's rate design;
- Section 9.6 explains how this rate design is based on a COSA study similar to the COSA study that supported FEI's approach in the 2001 Rate Design Application ("2001 RDA");
- Section 9.7 presents the results of the COSA analysis, revenue to cost ratios and range of reasonableness;
- Section 9.8 addresses future rate design; and
- Section 9.10 summarizes the rate design.

[223] Appendix D-1: EES Cost of Service Review Report , EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.1 "We concur that it is appropriate for the FEU to use an amalgamated COSA and rate design at the present time with postage stamp pricing. The current separate entities exist because of past ownership differences; however, that should not continue to drive separate rates as common ownership has been in place for several years. Postage stamp pricing is widely accepted in the utility industry and has been adopted by the Commission in the majority of cases across the Province. The introduction of postage stamp pricing across all of the areas served by the FEU is fair and equitable to customers and generally provides some overall advantages to customers."

9.2 Customers Impacted by Postage Stamp Rate Design

The FEU's proposed common rate proposal affects all residential, commercial and firm general service customers. These customers represent the vast majority of the FEU's 956,000[224] customers. The customers that are not impacted by the common rates proposal include:

- The special contract and large industrial transportation customers, including the FEVI large industrials customers (BC Hydro and VIGJV);
- The Inland region Rate Schedule 22A and bypass contract customers, consisting of 19 customers; and,
- The Columbia region Rate Schedule 22B and bypass contract customers, consisting of 7 customers.

These large industrial and special contract customers have specific rate structures and operating conditions. The two FEVI large industrials have long-term contracts in place and the Company is working with these customers on extensions and updates to their contracts appropriate for service from the Amalgamated Entity, subject to the approval of the amalgamation (Section 6 provides further information on the status of these discussions).

The Inland region large industrials mostly take Rate Schedule 22A firm service off the transmission system and, if close to the transmission system, have negotiated bypass contracts for service. The Columbia region large industrials take Rate Schedule 22B service off laterals connected to the TransCanada Pipelines Limited ("TransCanada") transmission system with specific operations and balancing requirements. The large industrial customers on Rate Schedules 22A and 22B are grandfathered and these rates have been closed to new large industrial customers since 1993. The FEU believe that these specific rates, rate structures and tariffs are still appropriate for the FEI large industrial customers and should remain unchanged at this time.

The remainder of this section discusses the proposed postage stamp rate design for the Amalgamated Entity's natural gas class of service.

9.3 FEI's Approved Rate Design Methodology is Basis for Common Rates

The FEU are proposing to use FEI's existing rate design methodologies as the basis for the rate design for the Amalgamated Entity. Adopting FEI's rate structures, and therefore adopting its underlying rate design methodologies, will result in fewer customers being impacted by changes in rate classes. As well, since the Amalgamated Entity customer base is primarily existing FEI customers, it is logical to carry over the principles that currently are accepted and in use for FEI customers. A comprehensive discussion of using the existing FEI rate design methodology for the common rates is included in Sections 9.5 and 9.6.

[224] FEU Gas Sales Statistics for BCUC 2011/12 Annual Report to the Legislature

This section:

- Provides a summary timeline of past changes in FEI's rate design;
- Explains the origins of the current rate design for FEI;
- Summarizes the subsequent approvals of *delivery* rate design; and,
- Explains the current and proposed treatment of *midstream and commodity* costs.

9.3.1 FEI RATE DESIGN TIMELINE

Highlights of the major rate design methodology approvals to FEI's gas cost and delivery rates over the past approximately 20 years are summarized in Table 9-1 below and are discussed further in this Section.

Table 9-1: FEI Rate Design Approved Methodologies Developed Over Time

FEI Application	Key Rate Design Methodologies Approved
1991 Rate Design	• Gas cost allocation methodology responding to the deregulation of the gas supply environment. • Development of regional Core Market gas cost rates for each of the three FEI regions. • Development of the Gas Cost Reconciliation Account ("GCRA") deferral account.
1993 Rate Design	• Development of postage stamp Core Market rate class basic and delivery rate structures (with the exception of the Columbia region) while maintaining regional large industrial rate structures.
1996 Rate Design	• Underlying postage stamping approach remained the same. • Rebalancing of residential and large industrial rates as a result of negotiated settlement process. • Higher basic charges more in line with fixed costs.
2001 Rate Design	• Underlying postage stamping approach remained the same. • Rebalancing of residential and large industrial rates as a result of negotiated settlement process. • Basic charges increased in line with fixed costs.
2004 Customer Choice Unbundling Program	• Underlying postage stamping approach remained the same; only addressed gas supply costs. • Unbundling of the gas supply costs for Core Market customers, commercial in 2004 and residential in 2007. • Separation of the GCRA into two deferral accounts, the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). • Otherwise largely retained same rate design for gas costs.

9.3.2 ORIGINS OF THE FEI RATE DESIGN

FEI's present rate design has its origins in a two phase rate design process that occurred in 1991 (referred to as "Phase A") and in 1993 (referred to as "Phase B").[225] The first phase addressed gas costs, and the second phase addressed the remainder of the rate design, including delivery rates.

9.3.2.1 1991 Gas Cost Allocation and Regional Gas Cost Rates

BC Gas Inc. was created in 1989 to amalgamate the divisions of Lower Mainland, Inland, Columbia (the "Divisions") and Fort Nelson, all of which had previously been separate legal entities. OIC No. 953-89 required all the Divisions of the company to continue to maintain separate rate bases, accounts and schedules of divisional rates until 1991. After returning to normal Commission regulation, BC Gas took steps to integrate the Divisions other than Fort Nelson.

In October 1991, BC Gas filed the 1991 - Phase A Application ("1991 Rate Design" or "Phase A"), which dealt principally with gas supply cost allocation methodology for Lower Mainland, Columbia and Inland regions.[226] By decision Order No. G-22-92, issued on February 1, 1992, the Commission approved the methodology to allocate costs associated with commodity purchases within the gas supply portfolio on a commodity-related basis, while allocating fixed costs associated with upstream pipeline capacity and storage[227] to customer classes based on coincident peak demand. This was approved on the basis that the firm sales customer classes who drive the pipeline capacity should be allocated costs based on their share of the required peak resource capacity. FEI also proposed, and the Commission approved, regional gas cost allocation and rates for the Lower Mainland, Inland and Columbia regions. This maintained regions consistent with the predecessor companies. The gas costs being addressed at the time consisted of all the gas supply costs, which was managed as a single portfolio.

With the implementation of the ESM in 2004, the FEI gas supply portfolio was subdivided into the commodity and midstream portfolios, and the costs within each have since been tracked separately. Although the FEI gas supply costs are now managed as two portfolios, the 1991 methodology is still used today for allocating the commodity portfolio and the midstream portfolio costs for the three regions of FEI.

9.3.2.2 1993 Rate Design

In April 1993, BC Gas filed the 1993 - Phase B Rate Design Application, which considered the allocation of all costs other than gas supply costs. The application also sought permission for consolidation and postage-stamp delivery rates for the Lower Mainland, Inland and Columbia regions for residential, commercial and general firm service customer classes (regional gas cost

[225] BCUC Order No. G-92-91 dated September 23, 1991 established the two-phase rate design review process.
[226] The Decision indicates at p.6 that Fort Nelson was excluded from the consolidation application as the municipality wished to remain independent and unconsolidated.
[227] Also includes the fixed cost component of any commodity supply netback contracts then in place.

allocation remained in place). BC Gas prepared a COSA study on a regional and consolidated basis. The COSA included industry accepted studies for the minimum system costs and customer weightings used to 1) classify distribution costs into demand and customer related components, and 2) to allocate customer related costs. The Company compared class revenues to allocated cost of service and considered 90 percent to 110 percent as a reasonable range to be used as a guide for rate setting.

In August 1993, the Commission approved consolidation of the Divisions for regulatory purposes, including the adoption of common accounting practices.[228] Later that year in Decision No. G-101-93, the Commission approved postage-stamp delivery rates for the Lower Mainland and Inland.[229] In the same Decision, the Commission declined to formally include the Columbia region delivery rates in the postage stamping approved for the Lower Mainland and Inland.[230] However, the Commission allowed the Company to set the same rates for Columbia at that time and approved a single set of tariff pages applicable to all of the Divisions effective January 1, 1994.[231] The Columbia region has had the Lower Mainland-Inland region delivery rates and rate structures in place since that time (over 18 years).

Order No. G-101-93 also approved the adoption of the proposed consolidated General Terms and Conditions to be applied across the BC Gas service area (other than Fort Nelson).[232] Further, the Commission supported the proposal of BC Gas to price interruptible service at a discount from firm service based on the value of service. The revised industrial rates came into effect on November 1, 1993 and the new residential and commercial rates came into effect on January 1, 1994.

9.3.3 RE-AFFIRMATION OF RATE DESIGN METHODOLOGY FOR FEI DELIVERY RATES

There have been two significant FEI rate design proceedings since the initial 1991/1993 BC Gas rate design proceedings. Both rate design applications were built on the methodologies established in 1991 and 1993, with minimal changes to the original approach.

The Commission's orders from these proceedings reinforced the fundamentals outlined above, particularly focussing on:

- Improved revenue alignment between classes; and,
- Appropriateness of the GT&Cs.

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[228] Consolidation decision issued in August 1993 by BCUC Order No. G-68-93.
[229] Page 6 of the Decision accompanying Order No. G-101-93, dated October 25, 1993.
[230] Page 10 of the Decision accompanying Order No. G-101-93 stated: "The Commission concludes that the Columbia Division is sufficiently different from the Inland and Lower Mainland Divisions that, as a matter of rate design principle, Columbia Division gas delivery charges for residential, commercial and general firm service customers should not be linked to those of Inland and Lower Mainland customers through postage-stamping at this time."
[231] BC Gas Tariff dated January 1, 1994, Page R-1.1 (Order No. G-101-93).
[232] The Company did not request postage stamping within the Fort Nelson region within the 1993 Rate Design Phase B Application.

These proceedings occurred in 1996 and 2001, and are discussed below.

9.3.3.1 1996 BC Gas (FEI) Rate Design Application

BC Gas filed a rate design application in 1996, which included a COSA study including a Minimum System Study. BC Gas maintained that a reasonable rate setting guide was a range for revenue to cost ratios between 90 percent and 110 percent. A Negotiated Settlement Process ("NSP") was undertaken and the resulting Negotiated Settlement Agreement ("NSA") was approved by Commission Order No. G-98-96 in October 1996. The primary element of the NSA was improved revenue alignment among customer classes to better reflect the customer class cost of service. The NSA also rationalised and simplified the industrial rate schedules and service agreements and clarified several of BC Gas' GT&Cs. The NSA also moved the residential and commercial monthly basic charges closer to the fixed costs of service.

In its Reasons for Decision approving the NSA, the Commission concluded: [233]

> *"The second settlement package addressed the company's proposals for rate shifts which would collect more of its costs from residential customers and less from industrial customers based on updated cost studies contained in the Application. After studying the negotiated settlement, the Commission is satisfied that it represents a fair proposal for all customer classes and has therefore approved this second settlement package.*
>
> *The results of this second settlement package received unanimous support from those parties actively participating in the hearing process who represented a broad range of interests including those of residential customers. However, following the publication of the hearing notice by the utility (Exhibit 9), the Commission did receive numerous letters of concern about the rate changes proposed in the Application, primarily from residential customers (Exhibit 7). …*
>
> *The Commission is satisfied that the majority of the customer concerns expressed in Exhibit 7 have been addressed by this settlement package. … Overall, the Commission is satisfied that the settlement treats all customers fairly and is consistent with the Commission's long term objective of more closely aligning customer rates with the customer-induced costs in each of the rate classes."*

9.3.3.2 2001 Rate Design Review

Four years after the 1996 NSA, the Commission directed[234] BC Gas to file another rate design application which was filed on February 5, 2001. A focus of the 2001 RDA was the allocation of

[233] Commission Order No. G-98-96, dated October 7, 1996, Appendix A, pp. 4-5.
[234] Commission Order No. G-75-00, dated August 4, 2000.

costs associated with newly completed capital projects[235] prior to 2001. The 2001 rate design addressed three main issues:

1. The level of rates between classes, or revenue realignment;
2. The structure of existing rate classes; and
3. The revisions required to the GT&C's, particularly for transportation customers.

The COSA analysis filed in the 2001 RDA revealed that each of the rate classes were adequately recovering their cost of service, based on a range of reasonableness of 90 percent to 110 percent, and that revenue realignment was not required. The analysis also indicated that the basic charge for residential and commercial customers should be increased along with a decreased delivery charge to more accurately reflect the recovery of fixed and variable costs. However, bill impact analysis showed that the impact of these changes would be significant for residential customers, thus the changes were proposed for commercial customers only.

At the request of participants at the workshop and the prehearing conference, the Commission hired an independent rate design consultant, EES Consulting, to review the 2001 COSA study. EES Consulting was tasked with validating the COSA model and assessing the extent to which FEI's Cost of Service methodology corresponded to generally accepted rate setting practices. EES Consulting verified the validity and robustness of the COSA study.

The 2001 RDA was the subject of an NSP and the resulting settlement document was approved by Commission Order No. G-116-01. The approved settlement document set out minimal changes to the rate schedules.

9.3.3.3 Outcome for Delivery Rates

The ongoing approvals of FEI's rate design applications highlight the underlying rate design methodology employed as being fair, just and reasonable. The Commission has accepted the appropriateness of the rate designs through its ongoing approvals, and the methodologies have generally received the support of interested parties in past years. The proposed rate design in this application is based on the principles and methodology applied in previously approved applications. EES Consulting has confirmed that it considers the rate design is appropriate.

9.3.4 GAS COST RECOVERY RATE DESIGN

A key aspect of FEI's rate design methodology since 1991 has always been that FEI purchases natural gas and propane on behalf of sales (i.e. non-transport) customers and passes these costs through to sales customers without a mark-up. Gas costs are recovered from customers through gas cost recovery rates. Generally speaking, gas cost recovery rates for the various

[235] 2001 Rate Design Application filed with the Commission February 5, 2001, p.1: "With regard to the total cost of service, a significant change is the addition of a number of major capital projects to the infrastructure supporting the gas utility. The most notable among these is the Southern Crossing Pipeline (SCP) project; others include the IBIS financial management system, the Mercury billing system, and new buildings and facilities."

entities and service areas are established based on the forecast cost of gas for the prospective 12-month period. As gas cost recovery rates are based on forecast costs, and the actual costs invariably differ from forecast costs, gas cost deferral accounts have been established for the various entities / service areas to accumulate the differences between the purchased cost of gas and the revenues collected through the gas cost recovery rates.

As discussed in Section 9.3.2.1, FEI dealt with the rate design associated with the allocation of gas supply costs in its 1991 Rate Design proceeding. There have been a number of changes to the gas supply portfolio since 1991, namely:

- The implementation of the ESM in 2004 to support the Customer Choice Program;
- In conjunction with the ESM, the gas supply portfolio costs and GCRA deferral account was divided into two portfolios, each with a new deferral account effective April 1, 2004 – namely, the commodity portfolio and CCRA deferral account, and the midstream portfolio and MCRA deferral account; and,
- The amalgamation of the FEW natural gas supply requirements within the FEI commodity and midstream portfolios effective January 1, 2010.

Although a number of changes have been made to the gas supply portfolio since the early 1990s, the current gas cost recovery *rate setting* process remains essentially unchanged from what was established in the 1991 Rate Design Application. As discussed further in Section 9.6.1.2, the allocation methodology established in the 1991 rate design continues to remain largely appropriate. Only a few minor changes are proposed for the allocation of gas costs within the amalgamated gas supply commodity and midstream portfolios as part of this Application.

9.3.5 FEI RATE DESIGN METHODOLOGY SUMMARY

The current FEI rate design for delivery, midstream and commodity rates evolved through a series of processes and Commission approvals. Each of the rate design proceedings dealt with a number of issues and built progressively on the previous proceedings and approvals. Each rate design for delivery rates undertook a COSA study and the Company maintained that a reasonable range for revenue to cost ratios was 90 percent to 110 percent and that this range could be used as a guide among other principles for rate setting. With respect to gas costs, the 1991 Rate Design proceeding established the gas supply cost allocation methodology which remains largely unchanged today, and which is markedly consistent with the cost allocation methodology proposed in this Application for use with the FEU gas supply commodity and midstream portfolios. For the reasons described below, the FEI rate structures represent a sound basis upon which to establish initial rates for the Amalgamated Entity.

9.4 Customer Mapping for the Amalgamated Entity

FEU's proposed common rate proposal requires the consolidation of the rate schedules of the various FEU entities. As discussed in Section 9.3, the FEU are proposing to adopt FEI's rate schedules for the Amalgamated Entity. This requires the moving or assigning (referred to as "mapping") of all of the FEVI, FEW and Fort Nelson customers to the appropriate FEI rate schedules. This section provides an overview of the customer mapping methodology utilized and why the customer mapping methodology applied is appropriate. In addition, this section will provide a summary of how the current FEVI, FEFN and FEW customers are mapped into the FEI rate structure for the Amalgamated Entity. The FEU believe, for the reasons set out below, that the mapping ensures that similar types of customers across the FEU operating areas will be charged the same rate upon the adoption of postage stamp rates.

9.4.1 CUSTOMER MAPPING METHODOLOGY

As discussed, the FEU are proposing that under common rates the Amalgamated Entity adopt FEI's rate structures. The first step in developing the methodology that would allow the consolidation of the rate schedules of the various FEU entities was to compare FEI's current rate schedules (described in Section 3.2.3.2) against the various service offerings of the other FEU entities to determine how to map customers to FEI rate structures. As discussed below, the FEU propose to move customers of the FEVI, FEW and FEFN utilities to FEI's Rate Schedules 1, 2 or 3. This is the same approach that was used in the mapping of Squamish customers in the amalgamation of Terasen Gas (Squamish) Inc. with FEI (then Terasen Gas Inc.) in 2007.[236]

9.4.1.1 Customer Mapping Methodology

The methodology that the FEU have chosen keeps the rate mapping straightforward and impacts the smallest number of customers. Residential customers are mapped to FEI's Rate Schedule 1 while all other customers are mapped to Rate Schedules 2 or 3 depending on their annual consumption. Rate Schedule 2 is for customers with an annual consumption of less than 2,000 GJ per year, while Rate Schedule 3 is for customers with an annual consumption in excess of 2,000 GJ per year. Rate Schedules 1, 2 or 3 also do not require a written contract between FEI and the customer to be executed, and therefore make the implementation of the customer mapping much more practical.

The FEU intend to make the other current FEI rate schedules, excluding Customer Choice, available to customers in Fort Nelson, FEVI and FEW upon amalgamation. As discussed in Section 6.5.1, the FEU will address the implementation of the Customer Choice Program as part of a future proceeding and does not expect to roll out the offering to customers currently in Fort Nelson, FEVI and FEW until November 1, 2014 at the earliest to allow sufficient time for customer education prior to the launch of the offering.

[236] FEI (then Terasen Gas Inc.) 2006 Annual Review and Mid-Term Assessment Review, November 6, 2006, Response to IR No.1.20.3 p.30.

9.4.2 FEVI MAPPING

The mapping of customers from the current FEVI rate schedules (described in Section 3.3.2.2) to the appropriate FEI rate schedule based upon the rate mapping methodology for the Amalgamated Entity was as follows:

- 100% of RGS customers were mapped to FEI Rate Schedule 1.
- 100% of SCS1, SCS2 and LCS-1 customers were mapped to Rate Schedule 2 as they have an annual consumption under 2,000 GJ per year per customer.
- Customers in LCS-2, LCS-3, HLF and ILF were mapped 100% into FEI Rate Schedule 3 as their annual consumption is in excess of 2,000 GJ per year per customer.
- AGS – AGS did not have a direct 100% mapping to one FEI rate schedule. Therefore, to map the AGS rate class into the appropriate rate schedules, the percentage of customers with consumption that exceeded 2,000 GJ per year was identified along with the corresponding percentage of total volume attributable to these customers. The results showed that 85% of the customers and 52% of the volume in AGS would be mapped to FEI Rate Schedule 2 while the remaining 15% of customers and 48% of the volume would be mapped to FEI Rate Schedule 3.

Table 9-2 below summarizes the mapping of FEVI rate classes onto FEI's.

Table 9-2: FEVI Rate Mapping

Rate Class	Consumption Requirements	FEI Rate 1		FEI Rate 2		FEI Rate 3	
		Customers	Volume	Customers	Volume	Customers	Volume
RGS	Residential	**100%**	**100%**				
AGS	6+ Residential Units			**85%**	**52%**	**15%**	**48%**
SCS1	0-199 GJ per year			**100%**	**100%**		
SCS2	200-599 GJ per year			**100%**	**100%**		
LCS1	600-1999 GJ per year			**100%**	**100%**		
LCS2	2000-5999 GJ per year					**100%**	**100%**
LCS3	6000+ GJ per year					**100%**	**100%**
HLF	6000+ GJ per year					**100%**	**100%**
ILF	6000+ GJ per year					**100%**	**100%**

9.4.3 FEW MAPPING

As described in section 3.4.2.2, the FEW tariff currently has only one rate schedule: the General Service Rate (SGS). This rate schedule serves all FEW customers from single family residences to large commercial customers such as large hotels. Within the General Service Rate Schedule, FEW has maintained additional customer segmentation for internal purposes based upon whether the end-use customer is a residential or commercial customer.

Commercial customers have also been segmented by annual consumption thresholds to assist FEW with managing the business. This internal segmentation was beneficial in mapping the FEW customers to the amalgamated rate schedules.

Mapping the FEW General Service Rate (SGS) Schedule, using the internal rate segmentation resulted in the following:

- SGS Residential was mapped 100% to FEI Rate Schedule 1.
- SGS Commercial and LGS 1 were mapped 100% to Rate Schedule 2 as their annual consumption was less than 2,000 GJ per year.
- All of the customers in LGS2 and LGS3 were mapped 100% into FEI Rate Schedule 3 as their annual consumption is greater than 2,000 GJ.

Table 9.3 below summarizes the mapping of the FEW customer segmentations onto the FEI rate schedules.

Table 9-3: FEW Rate Mapping

Rate Class	Consumption Requirements	FEI Rate 1		FEI Rate 2		FEI Rate 3	
		Customers	Volume	Customers	Volume	Customers	Volume
SGS Res	Residential	**100%**	**100%**				
SGS Com	0-599 GJ per year			**100%**	**100%**		
LGS 1	600-1999 GJ per year			**100%**	**100%**		
LGS 2	2000-5999 GJ per year					**100%**	**100%**
LGS 3	6000+ GJ per year					**100%**	**100%**

9.4.4 FORT NELSON MAPPING

The mapping of the Fort Nelson rate schedules (described in Section 3.2.4.2) to FEI's was as follows:

- Fort Nelson's residential customers (Rate 1) were mapped to FEI's Rate Schedule 1.
- GSR 2.1 was the one rate class in Fort Nelson that did not have a direct mapping as customers within this rate class can have consumption from 0-6,000 GJ per year. To split the customers in GSR 2.1, the same approach was used as in the FEVI mapping for AGS customers.
  - The percentage of customers with consumption that exceeded 2,000 GJ per year was identified along with the corresponding percentage of total volume attributable to these customers.
  - The results showed that 99% of the customers and 93% of the volume in GSR 2.1 would be mapped to FEI Rate Schedule 2, while the remaining 1% of customers and 7% of the volume would be mapped to FEI Rate Schedule 3.

- The customers in GSR 2.2 were mapped to FEI Rate Schedule 3 as their consumption exceeded 2,000 GJ per year.
- There are currently no customers in Rate Schedules 3.1 and 3.2; therefore, no mapping was required.
- Rate Schedule 25 - There are two customers in Fort Nelson served under Rate Schedule 25 and both of the sites are owned by the same company. These two Fort Nelson customers were mapped to Rate Schedule 3.
    - FEI has been in contact with the customer and understands that the customer may migrate any sites that continue to require natural gas for space heating to another FEI Amalco rate schedule (such as Rate Schedule 23) after January 1, 2014.

Table 9-4 below provides a summary of the FEFN Mapping.

Table 9-4: FEFN Rate Mapping

Rate Class	Consumption requirements	FEI Rate 1		FEI Rate 2		FEI Rate 3	
		Customers	Volume	Customers	Volume	Customers	Volume
Rate 1	Residential	**100%**	**100%**				
GSR 2.1	0-6000 GJ per year			**99%**	**93%**	**1%**	**7%**
GSR 2.2	6000+ GJ per year					**100%**	**100%**
Rate 25	Firm Transportation					**100%**	**100%**

9.4.5 MAPPING SUMMARY

The FEU believe the methodology used to consolidate the various entities' rate schedules into the amalgamated portfolio is the most appropriate; Rate Schedules 1, 2 and 3 do not require a written contract to be executed between FEI and the customer, making the transfer much more practical. Furthermore, some of the natural gas service offerings require the individual customers coming to business terms with the various natural gas marketers that serve the FEU customer base. As customers become educated on the various options available to them under the Amalgamated Entity, customers can then migrate to the various service offerings of their choice. For customers that elect Transportation Service, this option will be available to customers effective January 1, 2014 and Customer Choice will be made available no earlier than November 1, 2014.

9.5 FEI Delivery and Gas Cost Rate Structures Meet Rate Design Criteria for Use for the Amalgamated Entity

The well-established rate design for FEI was a logical choice for the rate design for the Amalgamated Entity given that it has been accepted previously and is familiar to most of FEU's customers. The 2001 RDA formed the basis for the current postage stamp delivery rate design proposals, and the FEI 1991 rate design formed the basis for the current postage stamp commodity and midstream gas cost rate design proposals. In order to confirm the suitability of that structure for continued use for the Amalgamated Entity, the FEU assessed how that rate structure would perform relative to a number of rate design principles, as discussed below.

9.5.1 BONBRIGHT'S RATE DESIGN PRINCIPLES

In considering the appropriate rate design, the FEU applied seven rate design principles based on those identified by Dr. Bonbright in his widely accepted work, "*Principles of Public Utility Rates.*"[237]

The seven principles adopted by the FEU for the rate design, in no particular order, are:

- Customer Impact;
- Fairness;
- Economic Efficiency;
- Stability;
- Ease of Understandability;
- Competitiveness; and
- Recovering the Cost of Service.

The seven principles are consistent with the principles applied in both the 2010-2011 TGVI Revenue Requirements and Rate Design Application and the 2001 BC Gas Rate Design Application, which the Commission's consultant at the time (EES Consulting) endorsed. The FEU believe that these principles provide an appropriate basis for the rate design for the Amalgamated Entity as well.

9.5.2 APPLICATION OF PRINCIPLES TO RATE DESIGN

Each of the seven rate design principles is described below with a brief explanation of how it is satisfied by the rate design proposed in this Application.

<u>Customer Impact</u>
Customer impact refers to the relationship between proposed rate changes and a customer's ability to pay.

Amalgamation and postage stamp rates will positively impact Vancouver Island and Whistler customers, as rate decreases are expected for these service territories.

The rates proposed for the Amalgamated Entity do not unduly impact the bills of FEI customers, as shown in the bill impact analyses described in Section 8.4.2. Because Fort Nelson will see

[237] James C. Bonbright, Albert L. Danielsen, David R. Kamershen, *Principles of Public Utility Rates, second edition,* 1988, p.383-384.

higher percentage rate increases due to common rates, the rate impact of amalgamation and common rates is proposed to be delayed for five years, and then phased in over the following 10 years. At the end of the 15-year transition period, Fort Nelson rates will be the same as for all other customers across the Province.

Fairness

For rate design, fairness implies the recovery of costs based on cost causation. The proposed rate structures require similar customers to pay similar delivery margins. Moreover, the proposed rates reflect the cost of service. This is demonstrated in the COSA study, discussed later in this section.

Economic Efficiency

Economic efficiency is defined as a state in which resources are optimally allocated to customers so as to minimize waste and inefficiencies. The proposed rate design for the Amalgamated Entity ensures that the revenues to be recovered from each rate class are closely aligned with the cost to serve them, and rewards those who utilize the system more efficiently through lower rates for customer classes with higher load factors. Load factors are a relative measure of how efficiently a customer class uses the system.

Stability

The principle of stability refers to the stability of rates themselves, with minimum unexpected rate increases that are seriously adverse to existing customers.

Longer-term rate stability in the smaller Vancouver Island, Whistler and Fort Nelson service areas is one of the drivers for this Application. The Company's rate proposals are intended to achieve greater price stability over the long-term than would otherwise be achieved through rates set to recover the cost of service for each utility individually. The proposed common rates across a combined entity will provide rate stability for the smaller service areas of FEVI, FEW and Fort Nelson (as discussed earlier in Section 6.3.2) by allowing a broader customer base to absorb any significant capital expenditures, customer or volume losses and declining use per customer without generating significant spikes in rates for any one service area.

Ease of Understandability, Administration and Rate Continuity

The principle of ease of understandability, administration and rate continuity refers to rates that are both easily understood by customers and easily administered by the Company.

Changes should be gradually implemented where possible, ensuring consistency and continuity in application so as to minimize customer confusion, and to promote customer fairness and equity. By capturing all utility customers under one common rate regardless of region, the principle of ease of understandability, administration and rate continuity is advanced. By amalgamating the rate schedules for FEVI, FEW and Fort Nelson with the FEI structure, the Companies will reduce the total number of rate schedules by 18.

Competitiveness

Competitiveness in rate design refers to designing rates in consideration of other fuel alternatives. The rates proposed in this Application for the Amalgamated Entity will have minimal impact on competitiveness of natural gas for the vast majority of customers currently served by FEI. On the other hand, the rates for FEVI and FEW will become more economic compared with the alternative fuels and become aligned with that experienced by FEI customers.

Recovering the Cost of Service

The last principle is that the rates must be sufficient to recover the cost of service. The proposed interim rates are sufficient to recover the Company's cost of providing service. The proposed interim rates for 2014 are based on the consolidated proposed revenue requirements for 2013 for the FEU, and also include any necessary adjustments to the cost of service to account for amalgamation, as discussed in Section 8.1.1.

In summary, the FEU believe the proposed rate design is consistent with established regulatory principles.

9.6 Delivery and Gas Supply Portfolio COSA Study

FEI's existing and proposed rates are designed to be cost of service-based, meaning that the rates charged to customer classes recover costs associated with that class and the customers as a whole recover the utility's cost of service. In order to accomplish this for the proposed rates, a COSA study has been undertaken to allocate delivery and gas supply costs to the customer classes driving those costs based on cost causation principles. This section first describes the general COSA methodology and then discusses the COSA study that forms the basis for the rate design. The FEU undertook the COSA study under the guidance of EES Consulting, who had also been retained by the Commission in 2001 to assess FEI's rate design. EES Consulting has provided its expert opinion that the COSA study approach is appropriate and is based on industry accepted standards. EES Consulting's report, "FEU Natural Gas Cost of Service Review," is attached as Appendix D-1.

9.6.1 DESCRIPTION OF THE COST OF SERVICE ALLOCATION STUDY METHOD

The COSA study is a widely accepted three-step method for the allocation of costs, endorsed by the American Gas Association[238] and EES Consulting.[239] It is the first stage in determining the appropriateness of a utility's current rates in light of the costs associated with providing service. The objective and methodology of the COSA study are summarized below.

[238] American Gas Association Rate Committee, "Gas Rate Fundamentals" (Fourth ed. 1987).

9.6.1.1 Objective of the COSA

The objective of the COSA study is to evaluate which customers, or customer groups, cause the utility to incur certain costs by linking system facility investments and operating costs to the services used by different customers. Rates are developed to ensure that each group of customers pays for the costs it causes the utility to incur.

Since any one type of customer alone does not incur the majority of costs, and because many utility investments serve many different groups of customers, the COSA study allocates costs amongst the various classes using factors appropriate for each type of expense. In the end, an allocated cost of service for each rate class is developed. When coupled with the revenues of the respective rate class, revenue to cost ratios are derived and are a tool used to gauge the reasonableness of the revenues (and rates) associated with each rate class. Revenue to cost ratios are discussed in greater detail in Section 9.7.1 below.

9.6.1.2 Elements of a COSA

In determining the appropriate allocation factors for each type of expense, three basic steps are involved:

1. Functionalization;
2. Classification; and
3. Allocation.

These steps constitute the basis of the COSA methodology and are discussed in further detail below.

<u>Step One: Functionalization</u>
The functionalization step involves separating the costs from the forecast period revenue requirements, commonly referred to as 'test year', into the major categories that reflect the utility's plant investment code of accounts and different services provided to customers. Examples of functional categories include transmission, distribution and marketing. After assigning plant costs functionally, related expenses are also functionalized along the same basis.[240]

<u>Step Two: Classification</u>
Once the costs from the forecast period revenue requirements have been functionalized, they are then classified based on three specific cost causation factors that drive the level of investment in utility operations: customer-related costs, demand-related costs and commodity-related costs.[241]

[240] Ibid. p.135
[241] Ibid. p.136

- **Customer-Related Costs:** Customer related costs are those that are incurred when attaching a customer to the distribution system, metering the customers' gas usage and maintaining the customers' accounts.[242] They may include capital costs associated with the investment in minimum size distribution mains, services, meters, house regulators, as well as marketing and customer accounting related activities. These costs then are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas.
- **Demand-Related Costs:** Demand-related costs are those associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains. Essentially, they refer to all costs associated with having peak capacity on standby and available upon peak customer demand.[243] Given this, transmission and distribution capacity, compressor costs, and midstream and LNG storage are classified as demand related costs with respect to the FEU's requirement for serving daily peak demands and the winter peaking season.
- **Commodity-Related Costs:** Commodity-related costs are those costs that vary with the volume of gas delivered to customers.[244] In the case of the FEU, other than the commodity supply purchased on behalf of the FEU's customers, few of the costs to operate the Companies' facilities are variable with respect to the volume of gas delivered to customers. Core Market commodity supply expenses are classified as commodity-related costs as a means to apportion the costs to all sales service customers.

Not all functionalized groups classify neatly into one of the three cost causation factors. In such instances, additional supporting studies are required to determine appropriate classifications amongst the cost causation factors. The costs of distribution mains, for example, are borne by both customers connecting to the system and by the maximum hourly or daily gas flow requirements. A Minimum System Study with Peak Load Carrying Capability ("PLCC") Adjustment, discussed below, is conducted and employed to aid the classification of distribution mains costs into both customer and demand related costs.

- **Minimum System Study:** The Minimum System approach assumes that a certain level of plant investment is required to serve the minimum loading requirements of customers throughout the service territory (i.e. those minimum costs are more dependent on the number of customers, rather than being variable based on demand). According to the American Gas Association, "*the closer a plant item is located to a customer; the more that particular item is related to the specific requirements of that customer*"[245] and therefore costs associated with such plant investment should be regarded as customer-related costs. The remaining per cent of costs is then attributed to the demand-related

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[242] Ibid.
[243] Ibid. p.137
[244] Ibid.
[245] Ibid. p.136

component since any costs associated with a system larger than this minimal plant investment are due to the fact that customers use a delivery quantity greater than the minimum unit up to the level of their peak demand. The result of this study determines the proportion of distribution mains costs that are customer related versus demand related.

The Minimum System analysis is only applicable to mains, since meters and services are classified as 100 per cent customer-related. Costs associated with meters and services are fully allocated based on customer weighting factors as each customer needs a meter and service regardless of the volume of service taken by the customer.

While the Minimum System, in theory, is designed to meet the minimal loading requirements for all customers, the actual mains designated as the minimum size are capable of carrying a load beyond the minimal load. The proportion of costs allocated to the customer-related component is therefore overstated and requires an adjustment to account for the peak load carrying capability of the minimum system.

- **PLCC Adjustment:** The PLCC adjustment involves determining the theoretical capacity of each of the distribution systems in the organization's total service area. To accomplish this, an average minimum system capacity per customer is calculated, which is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the demand for that rate class. The result accounts for the peak load carrying capability of the minimum system and effectively adjusts the proportion of costs allocated to the customer-related component to a more representative level.

<u>Step 3: Allocation</u>

When all forecast costs from the test year (in this case 2013) are functionalized into the major categories and classified by cost causation, they can then be allocated to each customer class. This allocation of costs is based on a customer's (or customer group's) contribution to the specific classifier selected, as determined by a number of analyses that evaluate customer requirements, loads, usage characteristics, system design and operations, accounting and physical asset records.

Demand-related costs are allocated to a customer group based on their contribution to the peak day demand measurement. Since each customer group possesses different service characteristics, allocation of demand-related costs based on a customer group's contribution to the peak day demand ensures that the appropriate proportion of those costs are allocated to those who require a larger share of the system capacity.

Commodity-related costs are allocated based on annual gas throughput (or energy) for each rate class.

For the allocation of customer-related costs, a Customer Weighting Factor Study is conducted. The Customer Weighting Factor Study aids in the allocation of customer-related costs associated with meters, services, customer administration and billing. Weighting factors are estimated values indicating the total relative value of meter and service assets or customer administration associated with a specific rate class as compared to other rate classes. Once the weighting factors have been calculated and assigned to each rate class, customer-related costs can be allocated appropriately across the company. This study helps ensure each rate class is assigned the appropriate proportion of customer-related costs based on cost causation.

9.6.1.3 Summary of COSA Methodology

The steps of functionalization, classification, and allocation are part of a well-established COSA methodology. By functionalizing costs from the forecast period revenue requirements, and then classifying those costs into customer-related, demand-related, and commodity-related costs, the COSA study allocates costs to the Company’s customer classes based on those customers or customer groups that cause them. The costs allocated to each rate class are then compared with the class revenues. The resulting revenue to cost ratios are used as a gauge of the reasonableness of the revenues (and rates) associated with each rate class.

9.6.2 THE APPLICATION OF COSA METHODOLOGY TO COST OF SERVICE ALLOCATION

This section describes how the FEU, under the guidance of EES Consulting, employed the above methodology for the COSA for this rate design. The COSA is largely consistent with the approach used in past FEI rate design applications, deviating only to incorporate different existing mechanisms across the individual entities and reflect changes to the asset base (i.e., the Mount Hayes LNG Storage facility is a new asset since the 2001 Rate Design) and operations since the last rate design. Details of the results of the COSA study are presented in Appendix J-2. Results of the revenue to cost ratios utilizing common rates, can be found in Table 9-10 of Section 9.7.2.

9.6.2.1 Comparison of Amalgamated Entity COSA to Previous FEI COSA

The following tables provide an overview of which aspects of the methodology employed previously by FEI have been held consistent and where modifications have been made for the COSA in this Application. The first table addresses delivery cost allocation methodology, and the second table addresses gas cost allocation.

Table 9-5: Delivery Cost of Service Methodology Comparison – 2001 (Existing) vs. Proposed

Application Section	Methodology Description	2001 (Existing) COSA	Amalgamated Entity COSA	Comments
9.6.2.3	Functionalization	• Seven functional categories: Gas Supply, LNG Storage, Transmission, Transmission Southern Crossing Pipeline, Distribution, Marketing, Customer Accounting	• Added eighth functional category: LNG Storage for Mt. Hayes	• Reviewed and recommended by EES Consulting. • Keeping Mt. Hayes separate from Tilbury allows alternative cost allocation methodologies to be assessed.
9.6.2.4	Classification	• Three cost classifiers: Customer-related, Demand-related and Commodity/Energy-related	• Same three classifiers used.	• Reviewed and recommended by EES Consulting. • Costs were classified to the same categories in 2011 as they were in 2001.
9.6.2.5	Allocation	• Customer-related costs allocated to classes based on customers or weighted number of customers. • Demand-related costs allocated to classes based on coincident peak demand. • Commodity/Energy-related costs allocated to classes based on annual sales or throughput.	• Added an extra allocator based on customers weighted for customer admin and billing. • No change to demand related and commodity/energy related allocators.	• Reviewed and recommended by EES Consulting. • Added extra weighted customer allocator for customer administration which more closely matches costs for customer class administration and billing.
9.6.2.4	Distribution System Mains classification	• Minimum System Study performed using 1 1/4” minimum sized mains. Result was to classify 25.0% customer related, 75.0% demand related.	• Minimum System Study performed using 2” minimum sized mains. Result was to classify 48.3% customer related, 51.7% demand related.	• Reviewed and recommended by EES Consulting. • Required due to a change in the minimum mains size installation standard to 2” from 1 1/4”.

Application Section	Methodology Description	2001 (Existing) COSA	Amalgamated Entity COSA	Comments
9.6.2.4	Peak Load Carrying Capability Adjustment	• Not used.	• Based on capacity determination of all distribution systems using only 2" mains as the minimum system.	• Reviewed and recommended by EES Consulting.[246] • Considers the change in the minimum system size standard.
9.6.2.5	Revenues associated with Contract Rate customers	• Bypass rate 22, 22A and 25 customers included in COSA, but not used for rate design determination as these rates are specified in the tariff supplement agreements.	• Revenues treated as a cost of service credit and allocated to all rate classes based on revenue margin.	• Reviewed and recommended by EES Consulting. • Places emphasis on Core Market and transport rate classes whose rates are subject to possible revision from postage stamping and rate design.
9.6.2.5	Revenues associated with Industrial Rate customers	• Non-Bypass industrial rate 22A and 22B customers included in COSA, but not used for rate design determination since these rates are closed to new customers.	• Revenues treated as a cost of service credit and allocated to all rate classes based on revenue margin.	• Reviewed and recommended by EES Consulting. • Places emphasis on Core Market and transport rate classes whose rates are subject to possible revision from postage stamping and rate design.

[246] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.14 "To better reflect this larger minimum size pipe, an offset to account for the peak load carrying capability (PLCC) of the minimum system was incorporated into the analysis."

In addition, the FEU have used as much as possible the cost allocation methodologies established in the 1991 Gas Cost Allocation Rate Design Proceeding, and applied these methodologies to the gas cost allocation approach for the Amalgamated Entity. Variations from the 1991 methodologies are summarized and presented in Table 9-6 below, and the rationale for the variations is discussed further in the sections below.

Table 9-6: Gas Supply Commodity and Midstream Cost Methodology Comparison: 1991 (Existing) vs. Proposed

Application Section	Methodology Description	1991 (Existing) Rate Design	Amalgamated Entity COSA	Comments
7.4.3	Gas supply portfolio amalgamation	• Not considered.	• Combined the FEU gas supply portfolios for the Amalgamated Entity including separate commodity and midstream portfolios.	• Reviewed and endorsed by EES Consulting. • Upon amalgamation the FEU propose to amalgamate the gas supply portfolio using FEI practices.
9.6.2.4	Commodity cost classification	• Gas cost allocation (GCRA) determined in the 1991 RDA. • Gas costs (GCRA) not split into commodity (CCRA) and midstream (MCRA) functions until the 2004 Customer Choice Program proceeding (1991 RDA allocations retained).	• Commodity costs to be allocated on a fully commodity-related basis which is consistent with current FEI treatment. • Maintain CCRA deferral account cost treatment across the FEU.	• Reviewed and endorsed by EES Consulting. • Expands the ESM and harmonizes commodity cost allocation across all FEU entities. Enables unbundling of gas costs on Vancouver Island, Whistler and Fort Nelson.
9.6.2.4	Midstream cost classification	• Gas cost allocation (GCRA) determined in the 1991 Rate Design. • Gas costs (GCRA) not split into commodity (CCRA) and midstream (MCRA) functions until the 2004 Customer Choice Program proceeding (1991 RDA allocations retained).	• Midstream costs to be allocated on a fully demand-related basis which is essentially the methodology that is used today for FEI. • Maintain MCRA deferral account treatment across the FEU.	• Reviewed and endorsed by EES Consulting. • Expands the ESM and harmonizes midstream cost allocation across all FEU entities. Enables future unbundling of gas costs on Vancouver Island, Whistler and Fort Nelson.

Application Section	Methodology Description	1991 (Existing) Rate Design	Amalgamated Entity COSA	Comments
9.6.2.4 & 8.1.1.1	Company Use gas allocation	• Maintained FEI methodology in place at the time. Embedded in O&M expenses.	• Propose to treat Company Use gas as part of O&M expenses and allocate based on peak demand to all non-bypass customers. • Consistent with current FEI treatment.	• Reviewed and endorsed by EES Consulting. • Harmonize approach across the FEU.
9.6.2.4 & 8.1.1.1	Unaccounted For ("UAF") gas allocation	• Not considered. Maintained FEI methodology in place at the time.	• Propose to treat UAF gas consistently across the FEU system and to treat as part of O&M expenses and allocate based on sales volume to all non-bypass customers (similar to treatment of Company Use gas).	• Reviewed and endorsed by EES Consulting. • Harmonize approach across the FEU. • Determine system UAF based on analysis of measurement data consistent with current FEI methodology using 5 year rolling average.

The COSA methodologies, model and results discussed herein have been validated by EES Consulting, and are consistent with the methodologies used in the 2001 and 1991 Rate Design Applications unless otherwise stated. EES Consulting has confirmed in its report that the FEU have followed the standard process that is generally accepted for embedded cost studies.[247] The complete EES Consulting COSA Report can be found in Appendix D-1 of this Application.

9.6.2.2 2013 Costs Have Been Used for the Amalgamated Entity's COSA

As the main objective of the Rate Design is to produce postage-stamped delivery, midstream and commodity rates applicable throughout the Amalgamated Entity's service area, the 2013 amalgamated rate base and amalgamated cost of service and gas supply portfolio were used as the basis for this COSA study. The rate base, cost of service and gas cost schedules for FEI Amalco were discussed in Section 8.1 and 8.2 and are attached in Appendix J-1.

Once the 2012-2013 RRA for the FEU entities is approved by the Commission, the FEU will update, as necessary, the amalgamated rate base and cost of service schedules for FEI Amalco. The proposed gas cost allocation methodology, once approved by the Commission, will form the basis for the quarterly commodity portfolio rate setting and annual midstream portfolio rate setting by the Amalgamated Entity. As such, the commodity and midstream rates effective January 1, 2014 will be reviewed and reset as part of a separate gas cost filing to be submitted after a decision on this Application.

9.6.2.3 Step 1: Functionalization of Rate Base, Delivery Cost of Service and Gas Costs

The FEU functionalized the 2013 proposed revenue requirement and gas supply costs into the following categories based on FEI's 2001 COSA:

1. Gas Supply: Commodity and Midstream;
2. LNG Storage: Tilbury;
3. LNG Storage: Mt. Hayes;
4. Transmission;
5. Transmission: Southern Crossing Pipeline ("SCP");
6. Distribution;
7. Marketing; and,
8. Customer Accounting.

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[247] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review," April 2012 p.9: "The FEU COSA uses an embedded approach, which is consistent with the accepted practice for the past 20 years. We believe this is the most appropriate methodology. Therefore, the FEU's embedded cost revenue requirement and existing rate base investment are used in developing the COSA results."

All of these functional categories were used in FEI's 2001 COSA, with the exception of the category for Mt. Hayes LNG Storage that was only put into service in 2011. The new functional category is appropriate as it allows ease of transparency for separate treatment of the costs associated with this new asset. EES Consulting reviewed the historical functional categories and concluded that these categories are also appropriate for the FEI Amalco COSA.[248]

9.6.2.4 Step 2: Classification of Functionalized Costs

Having functionalized the costs, the COSA study then classifies the functionalized costs into cost-causation categories as described above in Section 9.6.2.3. These cost causation categories are related to consumption behaviours, system demand, energy delivery or number of customers. A discussion on the Classification for each of the Functionalization categories follows.

<u>Classification of Gas Supply Function</u>
As discussed earlier in Section 7.4.3, the FEU proposes to combine the gas supply portfolios of FEVI, FEFN, FEW and FEI. This change involves adopting the Essential Services Model and the commodity and midstream structure currently in place for the FEI and FEW for the gas supply requirements of Vancouver Island and Fort Nelson.

Further classification of the costs related to the commodity portfolio and the midstream portfolio proposed for the Amalgamated Entity are described in the subsections below. The proposed classification of the gas supply costs remains generally consistent with that established within the 1991 Rate Design, while using different terminology, and adjusted to reflect the fact that the gas portfolio has since been divided into separate commodity and midstream portfolios.

<u>Classification of Gas Supply Function: Commodity</u>
The Amalgamated Entity gas supply commodity portfolio, based on the ESM currently in place for FEI and FEW, involves the acquisition of the baseload commodity requirements for the FEU. The FEU proposes that, effective January 1, 2014, the gas supply commodity costs will be classified as commodity-related and that a single, common CCRA will be utilized for FEI Amalco, consistent with the cost classification currently in place for FEI and FEW.

The FEI and FEW gas supply commodity portfolio includes all the costs incurred to provide the prescribed baseload commodity volumes to the supply hubs on a daily basis. The gas supply commodity costs include the costs for baseload gas related to purchasing gas at the supply hubs, any hedging (or other price risk management) costs, and an allocation of the gas supply management costs (i.e. Core Market Administration Expenses or "CMAE") for the commodity function. The FEI and FEW gas supply commodity costs, including any CCRA deferral account balances, are currently all classified as commodity-related as these costs are incurred for and

[248] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.11 "The functions defined by the FEU and the costs that were assigned to each function are appropriate given that they reflect the historic functions and follow the standard system of accounts of the utility. The functions generally differ in terms of usage, cost causation and which customer classes use the function."

directly correlated with the provision of the normalized, or baseload, annual demand volumes of gas for those Core Market customers remaining on the utility standard rate offering.

The cost allocation for the gas supply commodity costs continues to be appropriate and should remain unchanged from the current rate setting methodology where all gas supply commodity costs, including variances captured within the CCRA deferral account balance, is allocated on a commodity/energy-related basis.

The FEU are proposing that the current volumetric allocation of gas supply commodity costs utilized in the FEI and FEW rate setting model remain unchanged and be approved for use with the FEI Amalco Gas Supply Commodity portfolio. EES Consulting has reviewed the cost of gas commodity classification methodology and believes it to be appropriate.[249]

Classification of Gas Supply Function: Midstream

As discussed earlier in Section 7.4.3, the FEU proposes to implement the ESM on a system-wide basis and to fully amalgamate the gas supply portfolios. The gas supply midstream resources will be managed in a manner consistent with how the FEI (including FEW) midstream portfolio is currently managed. The FEU propose that, effective January 1, 2014, the gas supply midstream costs be classified as demand-related and that a single, common MCRA be utilized for the FEU, which is generally consistent with the cost classification currently in place for FEI and FEW.

The midstream portfolio includes the upstream pipeline capacity, upstream and market-area storage capacity (including storage services provided by Mt. Hayes), balancing and peaking resource requirements, as well as the mitigation activities.[250]

The gas supply midstream costs include the costs related to holding transportation and storage resources, as well as commodity supply in excess of the baseload volumes held in the gas supply commodity portfolio, required to ensure the utility can meet Core Customers' peak demand. The midstream costs also include the revenues related to mitigation of the transportation, storage, and commodity resources not required to meet the actual demand, and the relatively minor costs related to the allocation of the CMAE for the midstream function, the incentive payment for the Gas Supply Mitigation Incentive Program, and the UAF for sales customers.

Today, following the gas cost allocation methodology established in the 1991 Rate Design, the majority of the FEI (including FEW) midstream costs are classified as demand-related and

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[249] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.16: "The cost of gas, and other minor gas supply expenses are classified as energy-related, consistent with the Gas Supply rate base accounts. This is consistent with past practice. While rates for the cost of gas are updated more frequently than the costs for gas delivery, they are included within the COSA and are proposed to be consolidated along with all of the delivery costs. We have been advised that the gas portfolios will be consolidated, which will result in equalized costs across regions. We therefore believe the COSA treatment is appropriate."

[250] Such as the mitigation of transportation and storage capacity, the resale of surplus spot and peaking gas purchases, and off-system sales.

allocated to the rate classes based on the coincident peak demand of each rate class. A very small portion of the midstream costs are currently being classified as commodity-related and are allocated to the rate classes based on a volumetric basis, consistent with the 1991 Rate Design gas cost allocation methodology. However, the 1991 Rate Design was based on allocating gas costs within the single portfolio. Since that time the gas supply portfolio has been split into a commodity portfolio which relates to the acquisition of natural gas to meet the normalized annual demand, and a midstream portfolio which relates to securing the resources required to meet the peak demand while balancing the utilization of those resources to the actual daily load requirements. In other words, the midstream costs are required to meet the Core Market peak demand requirements and should be allocated on a peak demand-related basis. EES Consulting has reviewed the cost of gas midstream classification methodology and believes it to be appropriate[251].

As discussed previously in Sections 8.1.1.1 and 8.2.1.2.2, the FEU are proposing to recover the costs related to UAF from all non-bypass sales and transportation customers as part of delivery rates. Thus, the UAF costs currently allocated as part of the FEI and FEW midstream portfolio costs would be moved to O&M and recovered via delivery rates. This minor change to the current FEI and FEW midstream portfolio will result in the UAF costs being treated in a manner consistent with how the Company Use Gas is treated currently for FEI. Thus, upon amalgamation of the FEVI, FEFN, FEI and FEW gas supply portfolios, the gas supply costs allocated to the Amalgamated Entity midstream portfolio, and allocated on a demand-related basis, will be based on the current FEI and FEW midstream portfolio with the above mentioned minor changes. In other words, the FEI Amalco Company Use Gas, UAF, and Gas Control management fees will form part of the FEI Amalco O&M and be recovered via delivery rates.

<u>Classification of Tilbury Storage Function</u>

The Tilbury LNG Storage Facility ("Tilbury") was designed and constructed between 1969 and 1971. Since its commissioning in 1971, Tilbury has been in operation providing important system capacity to meet loads on the coastal transmission system during extreme winter peaking events. In this way, Tilbury primarily provides benefits related to security of supply, reliability and flexibility to serve loads within FEI's system during extreme events and by mitigating potential temporary operational issues associated with pipeline infrastructure supplying FEI's customers.

On June 4, 2009, the Commission issued Order No. G-65-09 approving Rate Schedule 16, which allows FEI to make liquid natural gas ("LNG") available to customers so as to allow the adoption of this fuel for emerging markets, such as transportation applications. Under this service, FEI utilises LNG supply from Tilbury for transport applications. FEI is also assessing how Tilbury can be further utilised for expanded transportation applications.

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[251] Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review," April 2012 p.16 "Midstream costs include charges for the use of upstream pipeline and storage facilities not owned by the FEU. Charges for those services are primarily tied to contracted capacity, which is set to cover forecasted peak day demands. It is therefore appropriate to treat the midstream costs as demand-related for purposes of the COSA and for developing costs by class when combined with the cost of gas."

The Tilbury LNG Storage facility was included as a function in the FEI's 1993, 1996 and 2001 rate design applications. The Tilbury function was consistently classified as demand-related in each of those proceedings. For the purposes of this Application, the FEU have maintained this classification approach for the Amalgamated Entity COSA.

<u>Classification of Mt. Hayes Storage Function</u>

The Mt. Hayes LNG Storage Facility ("Mt. Hayes") was successfully brought into service in 2011. Mt. Hayes provides system capacity for FEVI and a peaking gas storage resource as part of the FEVI and FEI gas supply portfolios. Mt. Hayes also improves the overall system reliability in the event of transmission system or upstream outages. The FEU also are currently assessing how the Mt. Hayes storage facility can also be utilized to offer LNG service for emerging markets including transport applications.

Since the Mt. Hayes storage facility has recently been added as a new asset in FEVI's rate base, the FEU are treating Mt. Hayes as a separate function in order to assess cost allocation alternatives. The FEU believe that it is appropriate to classify the Mt. Hayes storage function as demand-related at this time. EES Consulting has reviewed the Mt. Hayes LNG Storage facility classification methodology and believes it to be reasonable.[252]

<u>Classification of Transmission Functions</u>

Consistent with the 2001 COSA study, the FEI Transmission functions are classified as 100 percent demand-related since system capacity requirements are driven by the peak demand of each customer class. This classification is applied across FEI's separate transmission systems serving customers in different regions throughout the province, and as such the Companies believe that it is appropriate to maintain the classification of the transmission systems as demand related for the amalgamated entity. EES Consulting has reviewed the cost of transmission system classification methodology and believes it to be appropriate.[253]

<u>Classification of Distribution Function</u>

Costs for Distribution Mains have been split between demand and customer related components based on the Minimum System approach with PLCC adjustment. The Minimum System approach with PLCC adjustment was used in the 2009 FortisBC Inc. (Electric) Rate Design Application, which was accepted by the Commission in Order No. G-156-10 (Section 2.7). It has been used for this rate design analysis on the recommendation of EES

[252] Appendix D-1: EES Cost of Service Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.13 "A portion of the costs for Mt. Hayes are assigned to the midstream portion of the cost of gas, with the residual included in the delivery component of the COSA. This is consistent with previously approved practice." "Those costs are then included in rate base and have all been classified as demand-related."

[253] Ibid. p.13 "The cost of providing transmission service to a customer is considered to be directly proportional to the contribution to system peak demand that customer imposes on the system. All transmission rate base accounts are classified 100 percent demand-related. This is the case for basic transmission as well as the SCP transmission. This is appropriate because it is consistent with past practice and industry standards."

Consulting.[254] This method has been validated by EES Consulting as appropriate and consistent with past practice and industry standards.[255]

Minimum System Study

As discussed in Section 9.6.1.2, the Minimum System Study examines the various mains in place at the utility and separates the mains by pipe diameter and material (steel or polyethylene). Length of pipe installed and unit costs per length are then allocated to each pipe diameter to determine the actual total cost per pipe diameter for the entire distribution system.

To determine how costs should be split between demand and customer related components, the costs of the minimum system must be compared to the costs of the overall distribution system. To do so, the Minimum System Study assumes that the actual pipe diameters could be replaced with only those pipe diameters that comprise the minimum distribution system (i.e., all pipe diameters equal to or less than 2"). This approach multiplies the unit cost for each size of main by the length and then the cost of mains up to and including 2" is divided by the total cost. The percentage of Minimum System costs is attributed to the customer-related component and the remaining per cent is attributed to the demand-related component. The result is then used to classify the distribution system costs into customer related and demand related components. This is an important cost allocation step due to the significant size of the distribution system costs.

The last Minimum System Study was developed for the 2001 FEI (formerly BC Gas) Rate Design Application and produced results that allocated 25 per cent of the distribution mains costs to the customer-related component and 75 per cent to the demand-related component.

The Minimum System methodology for this Application aligns with that used in the 2001 Rate Design, but due to an increase in the minimum size standard for new installed mains from 1 ¼" to 2", the proportion of mains allocated to the minimum system is larger than in 2001. The percentage of costs allocated to the customer-related component has increased from 25 per cent to 48 per cent and the demand-related component has decreased from 75 per cent to 52 per cent.

The Minimum System Study results are presented in Appendix D-3.

Peak Load Carrying Capability (PLCC) Adjustment

The PLCC adjustment in this COSA involved determining the theoretical capacity of each of the FEU distribution systems assuming a 2" diameter of main. The capacity of the minimum sized distribution systems was then divided by the number of customers served by each distribution

[254] Ibid. p.15 "This adjustment recognizes that the minimum sized pipe assigned to the customer-related component has a peak load carrying capability, that is, it is large enough to carry more than just the minimal amount of gas associated with having a customer on the system. The PLCC adjustment is made to the allocation of demand-related costs among customers."

[255] Ibid. p.15 "Use of the PLCC adjustment was recently approved by the Commission for the FortisBC electric COSA. This adjustment is particularly warranted in light of the change in the minimum size pipe to 2 inches as the new size allows an even greater amount of gas beyond the minimum requirement to flow to the customer."

system and an average minimum system capacity per customer was calculated to determine the PLCC adjustment. This PLCC adjustment was then multiplied by the number of customers in each rate class, and the corresponding amount was added to the demand for that rate class. As noted by EES Consulting, the use of the PLCC adjustment was recently approved by the Commission for the FortisBC electric COSA.[256]

The PLCC adjustment for this Application was determined to be *0.225GJ per day per customer*[257]*.* When the adjustment is applied along with the Minimum System approach, the results more closely match the theoretical customer-related component of the distribution system. EES Consulting has reviewed the PLCC adjustment to the Minimum System and confirms that it is appropriate for the Amalgamated Entity COSA.

Classification of Marketing and Customer Accounting

The Marketing and Customer Accounting functions are generally classified as customer-related. Energy Efficiency and Conservation ("EEC") funding is classified as demand-related since EEC programs provide extra system peak capacity through energy conservation. This methodology is consistent with the past practice and is appropriate as the underlying cost causation for these functions is directly related to the customers served under each rate class and not based on their volumetric usage or demand. For the purposes of allocating costs to each customer class, the FEU developed separate customer weighting factors for customer administration and billing, described further in Section 9.6.2.5, which are appropriate for this Rate Design. EES Consulting has reviewed the marketing and customer accounting classification methodology and believes it to be appropriate.[258]

9.6.2.5 Step 3: Allocation of Functionalized and Classified Costs

Once the functionalized costs have been classified into demand, customer and commodity related components, these costs must then be allocated out to each of the rate classes based on appropriate allocation methodologies. The Company has, for the most part, allocated these cost components to the rate classes based on the approaches adopted and accepted by the Commission in the 2001 RDA, as well as the Company's earlier RDAs in 1993 and 1996.[259] Changes to the allocation from 2001 are summarized in Table 9-6 and reflect the addition of a

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256 Ibid. p.15 "Use of the PLCC adjustment was recently approved by the Commission for the FortisBC electric COSA. This adjustment is particularly warranted in light of the change in the minimum size pipe to 2 inches as the new size allows an even greater amount of gas beyond the minimum requirement to flow to the customer."

257 See Appendix D-3 for further information on how FEU calculated a PLCC Adjustment of 0.225 GJ/day/customer.

258 Appendix D-1: EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.21 "The second weighted customer allocation factor considered the cost of customer accounting and customer service for each rate class. The weighting factors were developed by FEU staff and were based on the estimated level of effort required per rate class. A standard weighting factor of 1.0 was used for the residential class, with other classes receiving a weighting factor relative to the level of effort for a residential customer."

259 Ibid. p.2 "We have reviewed both the COSA methodology and the COSA model itself to determine whether it is correct and appropriate. We find that the COSA follows standard utility practice, is generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and reasonable rates for the amalgamated utility."

customer weighting for customer administration and billing, the PLCC adjustment to demand, the inclusion of bypass and closed rate schedules as a revenue credit to the cost of service.

Allocation of Demand-Related Costs: Peak Demand Allocation Methodology

Consistent with the 2001 COSA, the coincident peak ("CP") approach was used in this rate design to allocate the demand related costs to each customer class. The CP approach continues to be appropriate as it allocates demand related costs to the customer classes that drive system capacity requirements based on the share of system capacity used by each of those classes.[260] The CP approach has consistently been used in FEI's 1993, 1996 and 2001 RDAs. The CP approach is described below.

As a first step, the load factors for the heat sensitive[261] customer classes (Rates 1, 2, 3/23, and 5/25) are determined. The Load Factor is defined as follows:

$$Load\ Factor = \frac{Average\ Daily\ Consumption}{Peak\ Day\ Consumption}$$

While there are exceptions, lower load factors are generally associated with increasingly heat sensitive load (i.e. residential and commercial customers) while higher load factors are normally indicative of process oriented load.

Consistent with the 2001 RDA, load factors are calculated using a three step linear regression methodology.

For each region and rate class separately:

1. Calculate the Peak Day Consumption:
    a) Regress 10 months of actual demand data against average monthly temperatures to establish the linear model parameters.
    b) Enter the resulting linear model with the regional peak day temperature to establish the peak day consumption.

2. Calculate the Average Daily Consumption:
    a) The average daily consumption is the normalized annual actual use per customer ("UPC") divided by 365.

3. Calculate the Load Factor:
    a) The load factor is the ratio of the average daily consumption to the peak day consumption.

[260] Ibid. p.20 "To be consistent with past COSA studies, the coincident peak day demand numbers were used for all allocation factors."

[261] Heat sensitive customers are those customers who have a significant portion of natural gas consumption associated with space heating and as such their natural gas loads are primarily driven by ambient temperature.

These load factors are then applied to the volumes of the applicable rate class for the forecast period to calculate the peak day demand. This methodology is used to determine the peak demand for firm Core Market customers (rate classes 1, 2, 3 and 5) and the companion firm transportation customers (rate classes 23 and 25). Consistent with past practice, Rate Schedule 6 (Natural Gas Vehicles) has been assigned a 100 percent load factor for determination of its peak demand since this class of customers is not heat sensitive. The sum of the classes determines total system demand which is then utilized to calculate the demand allocator for each of the functionalized classified categories of the cost of service. For the Distribution function, the demand-related allocator is calculated by applying the PLCC adjustment to the coincident peak demand for the customer classes in order to account for the peak capacity of the minimum system.[262]

Allocation of Customer-Related Costs

Customer-related costs are allocated on the basis of customers and weighted customers, using customer weighting factors which have been assigned to each rate class. The process of weighting number of customers involves the contribution of meter and services costs or customer accounting effort. For the purposes of this analysis, weighting factors were calculated for each rate class relative to the residential rate class as it represents the lowest cost rate class.[263]

Customer Weighting Factor Study:

Two types of customer weighting factors were calculated to allocate customer-related costs to each rate class.

1. **Customer Weighting Factors for Meters and Services:** This weighting factor examines the various types of meters used throughout the FEU and allocates costs associated with meters and services to each customer rate class. The factor is calculated by grouping meters by type for each rate class and then assigning the current installed costs for meters, meter sets, automatic meter reading instruments ("AMR"), telemetry and service lateral costs to the corresponding meter type. Once all costs are assigned to the meter types and rate classes, a current service and meter cost for each rate class is calculated. By comparing the current meter and service costs of each class to that of the residential rate class, customer weighting factors for meters and services are obtained. The customer numbers weighted for meters and services are then used to allocate costs associated with the Distribution customer-related component to each rate class.

[262] Refer to Appendix D-3 for the PLCC calculation, and Appendix D-1 EES Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.19 "Given the use of the PLCC adjustment as part of the minimum system treatment of distribution costs, the demand allocation factors are further adjusted by subtracting the PLCC amount times the number of customers in each rate class. This adjusted demand number represents the amount of demand that is not already included in the portion of distribution allocated on the basis of customers."

[263] The residential class is used as the basis for the customer weighting factors since meter and service capital costs are on average the lowest per customer for this class. All commercial and industrial classes utilize larger meter and service equipment, resulting in higher average meter and service costs relative to the residential class.

2. **Customer Weighting Factors for Customer Administration and Billing:** Large customers generally require a greater level of administrative effort or customer service than the average residential customer, therefore customer weighting factors are required to properly allocate customer administration, marketing and billing related costs to the various rate classes.

   Based on recommendations from the FEU's customer service and billing representatives, weighting factors for each rate class were developed which take into consideration: the frequency of meter reading; the use of AMR and the method of collecting and retaining load data; the amount of time spent by customer service responding to inquiries; marketing programs and costs for different customer groups; the existence of dedicated account managers for commercial and industrial customers; and the number of resources dedicated to each customer class for customer billing, measurement and marketing. The customer numbers weighted for customer administration and billing are then used to allocate costs associated with the customer administration to each rate class.

EES Consulting has reviewed the calculations for both weighted customer allocators and found the results to be reasonable.[264] For further details and a breakdown of all Customer Weighting factors by rate class, please refer to Appendix D-4.

Allocation of Commodity-Related Costs

The FEU believe, and EES Consulting has validated, that it is appropriate to allocate the commodity-related costs on the basis of annual consumption volumes for each of the Core Market rate classes since these costs vary directly with consumption.[265]

Allocation of Interruptible Customers

Interruptible customers are those customers who can be curtailed by the Company in the event that the demand for the firm customers exceeds the capacity to serve them. For the purposes of this COSA study, the interruptible customer classes are treated as a separate rate class as this approach leads to allocating the customer-related costs to these customer classes. Since the interruptible customers are curtailable, these customers do not drive system capacity additions; therefore, no demand-related costs are allocated to these customer classes in the COSA. This approach and methodology is consistent with the past practice and allocates a fair portion of costs to interruptible customers.[266] Since no demand-related costs are allocated to

[264] Appendix D-1: Cost of Service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012, p.20 "In addition to customers weighted for meters and services, we suggested that an allocator using customers weighted for customer accounting was more appropriate to use for some accounts and would better reflect cost causation. The FEU therefore added this third allocator to the COSA. EES Consulting reviewed the calculations for both weighted customer allocators and found the results to be reasonable."

[265] Ibid. p.20 "Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon annual gas sales for each class. As the energy allocator is used only for the gas supply function, it includes only the core customer classes."

[266] Ibid. p.19 "the COSA results were not used when setting the nonfirm rates and instead rates were based on a market driven discount relative to firm rates. This discounting approach was approved by the Commission in its

these customers, the interruptible rate classes are excluded from the presentation of Revenue to Cost Ratios.

Allocation of Revenues from Industrial, Contract Rate and Bypass Service Contract Customers

Contract rate customers are those customers that have historical negotiated rates which are fixed in their respective transportation service agreements. Contract rate customers served from the Vancouver Island transmission system include the VIGJV, BC Hydro (for service to Island Cogen Plant) and FEI serving customers in Squamish. A contract rate customer served in the East Kootenays is Elk Valley Coal Corporation known previously as Fording Coal Mountain or Byron Creek. All contract rates are approved by the Commission. Since the contract rates are established in an independent process, this Application contemplates no change to the service rates, terms and conditions applicable to the contract rate customers.

Bypass contracts are service agreements under which larger volume industrial customers, located in close proximity to upstream transmission pipelines, have negotiated with FEI for delivery rates that are reflective of the customer's cost of constructing its own pipeline to bypass the Company's system. With the exception of the specific rate, the terms and conditions of service in bypass contracts conform with the standard tariff under which the customer will be receiving service. All bypass rates are approved by the Commission. Since the bypass rates are established in an independent process, this application contemplates no change to the service rates, terms and conditions applicable to bypass customers.

Large industrial customers include the Inland region Rate Schedule 22A customers and Columbia region Rate Schedule 22B customers. Both of these rate schedules are closed to new customers. This application contemplates no change to the service rates, terms and conditions applicable to these closed large industrial customers.

As shown in Section 8.1 the forecasted revenue associated with closed large industrial, contract rate and bypass service contract customers has been treated as Other Revenue and credited to the cost of service. The Other Revenue credit to the cost of service from these customers is allocated on the basis of revenue margin allocated to each Core Market and non-contract transportation service rate class. The Company has adopted this approach because the contract rate and bypass customers all have rates set in their respective contracts and as such are not subject to rate changes which result from the cost allocation process. EES Consulting has reviewed the allocation of bypass and contract rate customer revenues as a cost of service credit and believes the approach to be appropriate for the Amalgamated Entity COSA.[267]

Phase B Rate Design Application Decision from October 1993, and subsequently continued to be used in later negotiated settlement agreements."

[267] Ibid. p.17 "A large portion of other revenue comes from customer revenues that are set at negotiated rates. The FEU has customers on contract rates that have been negotiated due to the ability of the customer to bypass the system or because of the size and unique characteristics of the customer. This includes certain industrial customers that are on rates that have been closed and are no longer available."

Allocation of Tilbury LNG Storage Facility

The Company believes the most appropriate allocation approach for the Amalgamated Entity is to continue to treat the costs associated with Tilbury as they have been justified and reviewed in previous Commission proceedings.[268]

Tilbury is primarily a peaking resource providing critical system capacity during extreme winter peaking events and provides system reliability and security of supply benefits. In the 2001 RDA, the total cost of service associated with Tilbury was included in the delivery margin and allocated based on peak day demand. All firm customers were allocated costs associated with Tilbury based on peak demand since all customers benefit from the peaking and operational flexibility that Tilbury provides. This approach was accepted by the Commission[269] and was a simple, easy to understand approach that appropriately allocated costs to those customers who benefit from Tilbury.

As discussed in section 9.6.2.4, Tilbury is also used to provide LNG supply under Rate 16 and FEI is currently assessing ways to further utilise the facility for transportation applications. Any future filings related to the expanding the uses of the Tilbury facility will address any associated cost allocation considerations at that time. For the purposes of this Application, however, FEU believes that it is appropriate to continue to use the allocation approach currently in place.

Allocation of Mt. Hayes LNG Storage Facility

In this section, the FEU describe how costs associated with Mt. Hayes are allocated, and why the Companies believe the most appropriate allocation approach at this time for the Amalgamated Entity is to treat the costs associated with Mt. Hayes as they have been presented in previous Commission proceedings. Additionally, the FEU will discuss the impact of amalgamation on the Mt. Hayes storage and delivery services agreement between FEVI and FEI.

FEVI owns and operates the Mt Hayes facility as part of its overall system and provides storage and delivery services to FEI pursuant to the terms of a long-term storage and delivery agreement (the "Storage and Delivery Agreement"). The facility provides transmission system capacity benefits to FEVI, and also provides a peaking gas storage resource that is included in the gas supply portfolios of both FEVI and FEI. The current cost allocation methodology effectively allocates costs to both delivery and cost of gas for FEVI and to cost of gas for FEI. This is consistent with our approach in past regulatory proceedings relating to the asset, first in the 2007 Mt. Hayes LNG Storage Facility CPCN ("Mt. Hayes CPCN") proceeding and then again in the 2010-2011 FEVI Revenue Requirements and Rate Design Application ("2010-2011 RRA RDA") proceeding. The cost allocation exercise undertaken by FEVI for Mt. Hayes has three components:

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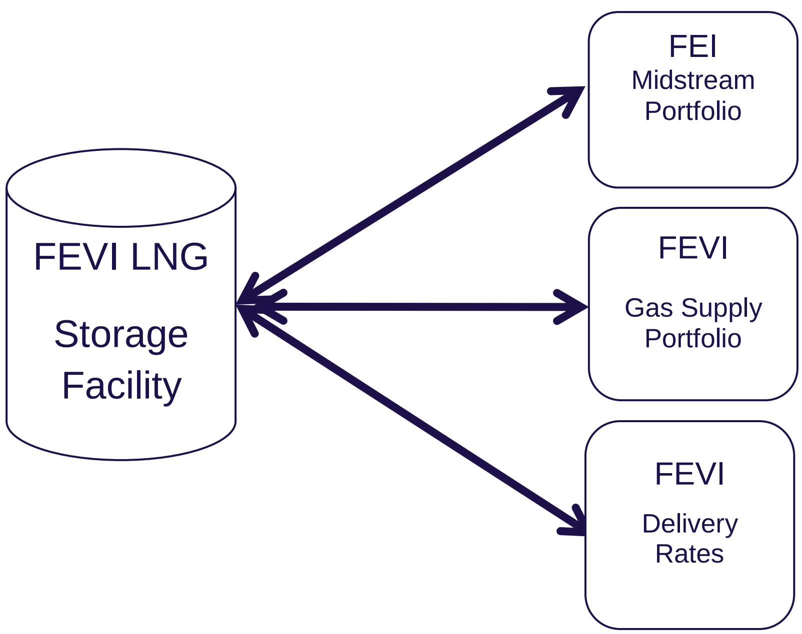
[268] Tilbury cost allocation was presented in the 1993, 1996 and 2001 FEI RDAs.

[269] Decision on 1993 Rate Design Phase B attached to Commission Order G-101-93, p.12: "In general the experts called to testify on behalf of Intervenors and Commission staff found that the technical approaches used in the BCGUL FDC study were reasonable and consistent with standard industry practice." This methodology was maintained in the 1996 and 2001 RDA NSPs.

1. Costs recovered through FEI midstream portfolio: Under the Storage and Delivery Agreement, FEI contracts for two-thirds of the capacity and deliverability of Mt. Hayes and any supplemental service that FEVI elects to make available to FEI from time to time. FEVI reserves the remaining one-third of the capacity less any supplemental service it has put to FEI, for its own use to meet its capacity requirements and to provide a peaking storage resource as part of its gas portfolio. The charges paid by FEI to FEVI are based on the value contracting for an alternate long term storage resource delivered to FEI's service territory. FEI recovers the charges it pays to FEVI for the services through its midstream rates. The revenues received from FEI offset the impact of the cost of service of Mt. Hayes on FEVI's revenue requirement.
2. Costs recovered through FEVI gas supply portfolio*:* FEVI similarly recovers a portion of the Mt. Hayes costs through its cost of gas based on the value of the storage services in its gas portfolio.
3. Costs recovered through FEVI delivery rates: The remaining Mt. Hayes costs net of the FEI revenues and FEVI gas portfolio allocation are recovered through FEVI's delivery rates.

This three part allocation exercise for the Mt. Hayes costs is illustrated in Figure 9-1 below.

Figure 9-1: Illustrative Allocation of Mt. Hayes Costs in the Mt. Hayes CPCN



Currently FEVI provides storage services to FEI pursuant to the terms of the Storage and Delivery Agreement approved by the Commission as part of the Mt. Hayes CPCN proceedings. Under the terms of the agreement, FEI pays firm demand charges to FEVI that were based on the avoided cost of acquiring incremental market area storage and firm redelivery to

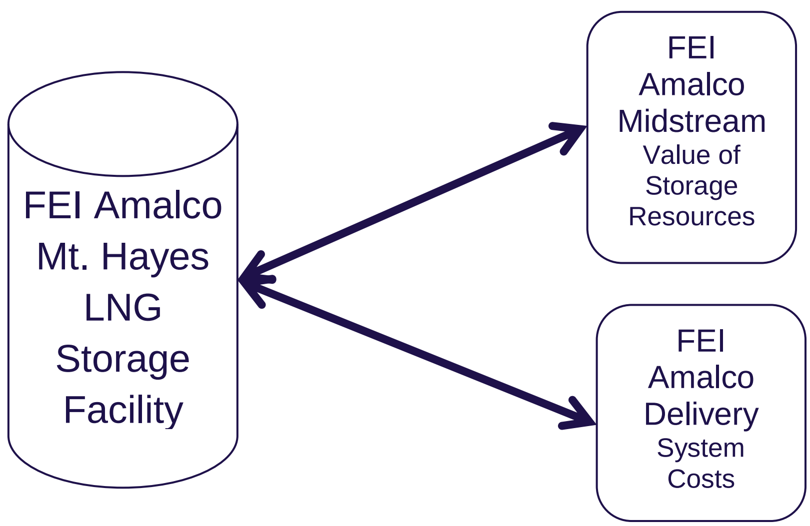
Huntingdon.[270] If full amalgamation of the entities is approved, upon the amalgamation, the obligations, rights and assets (including Mt. Hayes and the Storage and Delivery Agreement) of the amalgamating companies are in effect merged and the contracts between the amalgamating companies are thus cancelled. As such, the Storage and Delivery Agreement will be cancelled for the Amalgamated Entity. The Companies have accounted for the cancellation of the Storage and Delivery Agreement in this Application.

The Companies considered two options for allocating Mt. Hayes costs for the Amalgamated Entity, referred to as "Option A" and "Option B". Option A is the proposed approach, for the reasons set out below.

Option A (proposed)

The FEU have reviewed the Amalgamated Entity cost allocation approaches for Mt. Hayes and propose for the Rate Design to continue to allocate the value of storage resources associated with Mt. Hayes to midstream gas costs of the Amalgamated Entity. The remaining costs are allocated to the delivery costs and allocated based on coincident peak demand. Figure 9-2 presents the proposed cost allocation for Mt. Hayes for the Amalgamated Entity.

Figure 9-2: Illustrative Allocation of Mt. Hayes Costs for FEI Amalco



The FEU believe that allocating the value of storage associated with the Mt. Hayes LNG Storage facility as shown in Figure 9-2 to the midstream costs is reasonable as the storage services provided by Mt. Hayes are now integrated into the annual contracting plans for both FEVI and FEI as part of their gas portfolios and will continue to be include in the amalgamated gas portfolio. The annual value of storage charged to midstream costs would be $18 million and is consistent with the value presented in the Mt. Hayes CPCN application and again in the FEVI

270 Specifically, the demand charges were determined based on the assessment of the avoided cost of Jackson Prairie Storage expansion capacity and discounted Northwest Pipeline transportation capacity. Refer to Mt. Hayes LNG Storage Facility CPCN Application, June 5, 2007, Section 7.1.6 and Appendix D-5 for a copy of Market Area Storage Costs from the Mt. Hayes CPCN.

2010-2011 RRA RDA.[271] This storage resource valuation approach has subsequently been approved by the Commission.[272]

Option B

As an alternative, the Company has prepared an option for Mt. Hayes cost allocation that is consistent with the Tilbury cost allocation, whereby all Mt. Hayes costs are allocated to delivery. This approach has the benefit of being more straightforward and would recognise the system capacity and reliability benefits all customers receive as a result of Mt. Hayes being part of the integrated transmission system. Option A is being recommended in this Application as it most closely represents the current treatment of Mt. Hayes cost recovery. However, the Company believes Option B is a reasonable alternative in an amalgamated scenario, has benefits of simplicity and transparency, and the rate impact difference is minimal compared with Option A.

The FEU have prepared a comparison of the cost allocation approach under Option A and Option B. Table 9-7 shows how the total cost of service for Mt. Hayes LNG plant is allocated between delivery margin and midstream. Table 9-8 below shows the impact to the Core Market and transportation service customers using Option A as shown in Figure 9-2 above versus Option B (consistent with the Tilbury approach). Table 9-9 below shows the impact of these two options on the revenue to cost ratios for core and transport customers is minimal in 2013. The results also show that both approaches yield very similar outcomes on rates.

Table 9-7: Comparison of Mt. Hayes Cost Allocation Approaches – Allocated Between Delivery Margin and Midstream

		CORE		TRANSPORT		TOTAL
Allocation Methodology		**Del Margin**	**Midstream**	**Del Margin**	**Midstream**	
Allocate Mt. Hayes storage costs to Midstream Costs and Delivery Margin for FEI AMALCO	**Option A**	$7,286	$18,039	$853		$26,178
Allocate Mt. Hayes storage costs to Delivery margin for FEI AMALCO	**Option B**	$23,433		$2,745		$26,178

Table 9-8: Comparison of Mt. Hayes Cost Allocation Approaches

Allocation Methodology		**CORE**	**TRANSPORT**	**TOTAL**
Allocate Mt. Hayes storage costs to Midstream Costs and Delivery Margin for FEI AMALCO	**Option A**	$25,325 **96.7%**	$853 **3.3%**	$ 26,178
Allocate Mt. Hayes storage costs to Delivery margin for FEI AMALCO	**Option B**	$23,433 **89.5%**	$2,745 **10.5%**	$ 26,178

Note: *The numbers in the tables above are in $000's*

[271] See FEVI 2010-2011 RRA RDA p. 422 Table D-1-10 and Appendix D-5 for a copy of Market Area Storage Costs from the Mt. Hayes CPCN.

[272] Order No. G-161-11 dated September 28, 2011, " An Application by FortisBC Energy (Vancouver Island) Inc. for Approval of Storage and Delivery Rates Effective April 1, 2011 in the Storage and Delivery Agreement with FortisBC Energy Inc. Tariff Supplement No. 4." Rates approved for LNG service are based on the value of third party market area storage services as presented in the Mt. Hayes LNG Storage Project CPCN proceeding.

Table 9-9: Comparison of Mt. Hayes Cost Allocation Approaches

Rate Schedules	Revenue to Cost Ratio (Option A)	Revenue to Cost Ratio (Option B)	Variance
Rate 1 – Residential	93.4%	93.5%	-0.1%
Rate 2 – Small Commercial	104.6%	104.4%	0.2%
Rate 6 – Natural Gas Vehicle	112.7%	113.7%	-1.0%
Rate 3 & 23 Combined	107.9%	107.5%	0.4%
Rate 5 & 25 Combined	110.4%	110.2%	0.2%

As discussed in section 9.6.2.4, the Companies are assessing how Mt. Hayes may be used to provide LNG service to support transportation applications. Any future filings expanding the uses of Mt Hayes will address any cost allocation considerations at that time. For the purposes of this Application, however, FEU believes that it is appropriate to use the allocation approach described by Option A.

Allocation of Transmission Systems

The Companies propose to roll-in all transmission system costs together and allocate based on coincident peak day demand. This means that FEI transmission system costs including Coastal Transmission system, Interior Transmission system, Southern Crossing Pipeline, and the FEI transmission laterals off the Westcoast Energy Inc. and TransCanada pipelines would be rolled in together with the FEVI transmission system (including the Whistler pipeline).

The Companies believe that, under the amalgamated scenario (FEI Amalco), it is appropriate to roll-in the costs of these transmission systems and allocate them to Core Market and Transport customers based on the coincident peak day demand for these reasons:

1. All of these transmission systems serve the same function of acting as a supply source to feed the distribution systems in each area of the Province
2. Costs associated with these transmission systems are driven by each customer class's contribution to the peak day demand on the system.

Currently, there are contractual arrangements amongst FEI, FEVI and FEW for transportation service on the respective transmission systems. As discussed in Section 7.2.4 and the Draft Order attached as Appendix K-2, if full amalgamation of the entities is approved, upon amalgamation, the obligations, rights and assets of the amalgamating companies are in effect merged and the contracts between the amalgamating companies are cancelled. As such, all inter-company Transportation Service Agreements will be cancelled.[273]

[273] Appendices D-6, D-7, D-13 and D-16 attach inter-company agreements including the Wheeling Agreement between FEI and FEVI; the Transportation Agreement between FEVI and FEW, the Squamish Transportation Agreement between FEVI and FEI, and the Contribution Agreement between FEW and FEVI.

9.6.3 SUMMARY OF ALLOCATION METHODOLOGY APPLICATION TO THE COSA

The FEU conducted a fully allocated cost of service study that combined each of FEU's utilities into an Amalgamated Entity. The Companies used past rate design methodologies as a basis for this rate design for the Amalgamated Entity. The COSA approach employed, including the rate design principles applied to the Amalgamated Entity, is the same approach that FEI used in FEI's 2001 and 1991 Rate Design Applications. EES Consulting has reviewed the COSA approach and confirmed that it is consistent with industry practices and appropriate for the Amalgamated Entity. The FEU had to adapt the FEI 2001 methodology to account for changes in major assets, operations and standards since 2001. These alterations were reviewed and recommended by EES Consulting.

9.7 Class Revenue and Cost Comparisons

This section begins with a discussion of Revenue to Cost ("R:C") ratios and their use in evaluating rates with respect to the FEU's ability to adequately recover the cost of service. Moreover, a discussion surrounding the appropriate range of reasonableness to use is presented based on past precedent. The section ends with the R:C ratio results for the Amalgamated Entity.

9.7.1 REVENUE TO COST RATIOS AND THE RANGE OF REASONABLENESS

In this section, the FEU explain how R:C ratios are used in evaluating the adequacy of rates and discuss the use of a "range of reasonableness" to assess the appropriateness of the resulting R:C ratios.

9.7.1.1 Revenue to Cost Ratios Defined

The COSA study is one of the primary tools used to establish cost guidelines for the evaluation of rate class revenue levels. This evaluation process includes a comparison of the revenue margin for each customer class with the corresponding cost to serve them. This comparison is referred to as the R:C ratio, and the ratio shows whether the rates charged to each rate class adequately recovers their allocated cost of service.

9.7.1.2 The "Range of Reasonableness" Defined

R:C ratios are assessed based on whether or not they fall within an established "range of reasonableness". The FEU submit that the appropriate range of reasonableness for the FEU is 90 per cent to 110 per cent.

Ideally, the revenue to cost ratio should equal 100 percent for each rate class, indicating that the rates charged are in fact economically efficient and fair since the revenues recovered from each rate class would exactly equal the indicated cost to serve them. However, achieving unity implies a level of precision that does not exist with any COSA. As a cost of service study necessarily involves assumptions, estimates, simplifications, judgements and generalizations, a "range of reasonableness" is warranted when evaluating the appropriateness of the revenue to cost ratios.

The result of the COSA study for each rate class is considered in light of this "range of reasonableness" and each rate class that falls within that range is deemed to be at unity. If a rate class falls out of the "range of reasonableness", this indicates that revenues are either insufficient in covering the cost of service or exceed the cost of service, which suggests that rate rebalancing may be in order. The "range of reasonableness" is therefore used as an indication of the rate classes that require re-balancing. Even if all of the rate classes fall within the "range of reasonableness", further re-balancing may be necessary in light of rate class characteristics and rate design objectives.

The appropriate "range of reasonableness" will depend on the particular circumstances of a public utility. Recent Commission decisions with respect to electric utilities in British Columbia regarding the "range of reasonableness" suggest that a "range of reasonableness" of 95 per cent to 105 per cent is appropriate. Specifically:

- By Commission Order No. G-130-07 in response to BC Hydro's 2007 Rate Design Application, the Commission determined that a "range of reasonableness of 95 per cent to 105 per cent [was] the correct range for the purpose of future rebalancing in the circumstances of BC Hydro."[274] The rationale for the decision was based in part on the "the known system demand and demand metering of large commercial and industrial customers" and "the accuracy of the relatively sophisticated load research analysis."[275] As a result, the Commission panel determined for BC Hydro "that the appropriate target R/C ratio in each class is unity or one... and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness."[276]
- Similarly in Order No. G-156-10, dated October 19, 2010, the Commission found that "the appropriate range of reasonableness of 95% to 105% is the correct range for the purpose of future rebalancing in the circumstances of FortisBC [electric]."[277] Like the BC Hydro decision, the Commission determined that the appropriate target R:C in each rate class to be one, with future rebalancing necessary only when customer classes fell outside the range. The Commission also accepted FBC's position that the "range of reasonableness" is "based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the range of reasonableness for BC Hydro."

Although there are precedents for a "range of reasonableness" of 95 per cent to 105 per cent in the case of BC electric utilities, the FEU submit that this range is not appropriate for natural gas utilities. In the case of the BC electric utilities, there is relative certainty in load research

274 2007 BC Hydro Rate Design Application Decision p. 71.
275 Ibid.
276 Ibid.
277 2009 FortisBC Inc. Rate Design Application Decision p. 77.

analysis that exists from known hourly system demand and demand metering data for large commercial and industrial customers with respect to the coincident peak demand calculation. Such certainty does not exist for natural gas utilities.

- First, equivalent load research analysis for natural gas utilities does not draw from hourly system demand data but rather from more imprecise daily system demand data.
- Second, the load research analysis employed by natural gas utilities is based on peak days that reflect extreme weather planning conditions since natural gas demand is largely driven by temperature. This further diminishes the accuracy of natural gas forecast loads compared to those produced by electric utilities that use actual or forecast loads under normal weather conditions. Since peak day loads are fundamental to cost allocations for natural gas utilities, greater data uncertainty with respect to peak day loads result in greater uncertainties in COSA results.

For these reasons, natural gas utilities have relatively imprecise system demand data compared to those used for electric utilities.

Policy considerations specific to natural gas also support a wider "range of reasonableness". For natural gas utilities, the long standing precedent for the "range of reasonableness" for the revenue to cost ratio has been 90 per cent to 110 per cent. In Commission Order No. G-42-91 that ruled on Ocelot Chemical's application seeking reconsideration of the Commission's ruling on Pacific Northern Gas's 1991 Rate Design Application (Order No. G-23-91), the Commission recognized the subjectivity inherent in cost allocation:

> *"The Commission is also cognizant of the considerable reliance upon judgement involved in the undertaking of a cost of service study. Although judgement is required in lesser amounts to determine the specific component of the total cost of service and functionalization of costs, significant judgement is required to classify costs between capacity, commodity and customer components. Even greater judgement is required in determining the appropriate method to allocate these costs amongst rate classes. For example...different classes of customers impose different levels of risk on the utility, but quantifying the appropriate cost differential is not attempted in these studies. Finally, there are benefits attributable to serving certain classes of customers but these, too, have not been included as an offset against costs within the study as they are not easily quantified."*[278]

This reliance on judgement led the Commission to conclude:

> *"Given the imprecision inherent in cost of service studies in general, and in particular the studies in issue, the Commission believes that as long as revenues from a particular class of service and costs allocated to that class of service do*

[278] Commission Order No. G-42-91 p. 29.

not differ by more than 10 percent, there is no compelling evidence to determine that the cost of service results indicate rate restructuring is required."[279]

The Commission also accepted as a guide to rate setting, a "range of reasonableness" of 90 per cent to 110 per cent in the BC Gas 1993 Phase B Rate Design.[280] The same range of reasonableness was used in the BC Gas 1996 Rate Design[281] and the Terasen Gas Inc. 2001 Rate Design.[282]

EES Consulting has considered the appropriate "range of reasonableness" and concludes that a wider range of 90 per cent to 110 per cent is warranted for natural gas utilities.[283]

Consistent with past precedent and EES Consulting's recommendation, the FEU have applied a "range of reasonableness" of 90 per cent to 110 per cent in this Application.

9.7.2 COST OF SERVICE ALLOCATION STUDY RESULTS

Table 9-10 below provides the revenue to cost ratios for each of the Amalgamated Entity rate classes based on the proposed 2013 revenue requirement and COSA study.

Table 9-10: Amalgamated Entity Rate Class Revenue to Cost Ratio

Rate Schedule	Revenue to Cost Ratio
Rate 1 – Residential	93.4%
Rate 2 – Small Commercial (<2000 GJ/yr)	104.6%
Rate 6 – Natural Gas Vehicle	112.7%
Rate 3 & 23 Combined	107.9%
Rate 5 & 25 Combined	110.4%

For those rate classes that include customers who take transportation service (Rate Schedules 23, 25 and 27), an imputed cost of gas was included, in the determination of the revenue to cost ratios, in accordance with past Commission requests,[284] to achieve consistency and a basis for comparison with firm customers.

Table 9-10 above shows that Rate Schedule 6 and Rate Schedules 5/25 combined are only marginally higher than the 110 per cent upper end of the range of reasonableness while no

279 Ibid.
280 Order G-101-93, Decision, p.12: "In previous decisions the Commission has accepted a 10 percent band as reasonable."
281 Order G-98-96 BC Gas Utility Ltd. 1996 Rate Design Proposals
282 Order G-116-01 BC Gas Utility Ltd. 2001 Rate Design Application
283 Appendix D-1 EES Cost of service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review, April 2012", p.27: 'The FEU has proposed using a 90% to 110% revenue to cost ratio "range of reasonableness" for setting proposed rates under the amalgamation. We consider this to be a reasonable range for use when considering the adjusted revenue to cost ratios for the FEU.'
284 BCUC Order No. G-42-91 p. 3. Rate Classes 23, 25, and 27 are transportation options for Rate classes 3, 5 and 7 respectively. Since allocated cost for Rates 3, 5 and 7 includes cost of gas, a cost of gas is imputed for Rates Classes 23, 25 and 27 to ensure consistency and to show revenue to cost ratios on combined basis for Rates 3 & 23, Rates 5 & 25 and Rates 7 & 27.

classes are less than the lower end of the range. FEU believes that no rebalancing is required at this time for the following reasons:

1. If the FEU rebalanced rates based on a guideline of a 90% to 110% range, a decrease of just $13,000 and $377,000 in delivery revenues would be required for Rate Schedule 6 and Rate Schedules 5/25 respectively. This amounts to just 0.05 percent of the total delivery revenues for all rate schedules.
2. After common rates are implemented, the FEU expect some movement of customers as they adjust to the choices amongst the FEI rate classes. It is therefore prudent to see what the results of any customer movement amongst rate classes would be before doing any rate rebalancing.
3. As the consolidation of the rate schedules will already result in changes for certain customers, it is reasonable not to make further adjustments at this time.

For these three reasons, the FEU believe that the revenue to cost ratios presented in Table 9-10 above represent a reasonable range for setting rates for all rate schedules.

For comparison purposes only, FEU has prepared rebalanced scenarios by moving revenue to cost ratios for each of the Rate Schedules to fall within the range of 90% to 100%; 95% to 105%; and, 100%. The results of these rebalanced scenarios have been summarized in Appendices I-6 and I-7.

9.8 Future Rate Design

As discussed above, the FEU anticipate some movement of customers as they adjust to the choices amongst the FEI rate classes. As discussed by EES Consulting on page 30 of their report in Appendix D-1 of this Application:

"As this is a significant change for many customers in terms of both the rate level and in some cases the rate design, it is recommended that no other rate design changes be made until these new rates are implemented and the utility ensures that all issues related to the rate migration are resolved. Changes to the rate design would be more appropriate to consider in future applications."[285]

The FEU expect that a period of two years from the implementation of common rates is the required timeframe to evaluate the results of any such movement. Therefore, if amalgamation and the adoption of common rates is approved, the FEU will review the cost allocation and customer segmentation in 2016, after seeing the effects of the migration of customers to new rate schedules or new service offerings.

[285] Appendix D-1 EES Cost of service Review Report, EES Consulting, "FEU Natural Gas Cost of Service Review, April 2012", p.30.

9.9 Rate Design Summary

In this rate design, the FEU conducted a fully allocated cost of service study that combined each of the FEU's four rate bases into an Amalgamated Entity and produced common rates applicable across all service areas. To serve as the foundation for the Amalgamated Entity, the FEI rate structure was adopted. The availability of the full suite of service offerings to FEI customers currently, in addition to FEI carrying the majority of the FEU's total customer base, made mapping FEVI, FEW and FEFN rate schedules to the corresponding FEI rate schedules appropriate and practical for our customers. Mapping of the FEVI, FEW and FEFN rate schedules to FEI's rate schedules was completed based on annual consumption thresholds and contractual requirements of the current FEI Rate Schedules.

The COSA approach employed, and the rate design principles applied to the Amalgamated Entity are largely consistent with the Commission-reviewed rate design approach used for the FEI 2001 RDA. EES Consulting has confirmed that the approach is reasonable and consistent with industry practices.

10 STAKEHOLDER ENGAGEMENT

This section describes the stakeholder engagement planned and conducted for this Application. The stakeholder engagement plan undertaken by the FEU was designed to provide information to stakeholders and provide meaningful opportunities for feedback. The FEU consulted broadly with its customers through market research, direct mail and public information sessions. The FEU also conducted more focussed consultation with key stakeholders, such as Commission staff, stakeholders who have taken an interest in the Companies' regulatory review processes in the past, select industrial customers and the Mayor and Regional Council members of the Northern Rockies Regional Municipality ("NRRM"). In this section, the FEU provide a description of these activities and the feedback received from stakeholders.

This section is organized as follows:

- Section 10.1 provides an overview of the stakeholder engagement for the Application;
- Section 10.2 describes the objectives of the stakeholder engagement plan;
- Section 10.3 describes the key stakeholder engagement activities;
- Section 10.4 describes the broader stakeholder engagement activities;
- Section 10.5 summarizes the feedback and key findings obtained through the stakeholder engagement activities;
- Section 10.6 describes the activities comprising the stakeholder engagement plan post filing; and
- Section 10.7 is a summary of the stakeholder engagement for the Application.

10.1 Overview of the Stakeholder Engagement for the Application

The stakeholder engagement for this Application involved communication and consultation with key stakeholder groups as well as with the broader stakeholder community. Communication and consultation are both designed to enable stakeholders to understand the purpose and content of an application, as well as the direction and vision of the Companies. Communication involves the provision of information to educate stakeholders on policies, goals and proposals for the Company. Consultation on the other hand, implies a dialogue with stakeholders where input is sought to define dimensions of an issue or comment on a proposed policy. Consultation involves the exchange of ideas, such that the FEU can take into account or respond to feedback from stakeholders in its proposals.

The stakeholder engagement began with the FEU's 2012-2013 RRA, which discussed the proposal for amalgamation at a high level.[286] The FEU's intent to amalgamate and implement

[286] FortisBC Energy Utilities 2012-2013 Revenue Requirements Application (Section 1.2.5).

common rates has also been communicated and discussed in previous regulatory applications and proceedings.[287]

Following the filing of the 2012-2013 RRA, the FEU identified and began consultation with key stakeholders. Key stakeholders are those that the FEU identified as potentially being particularly impacted by the proposals included in the Application. These included stakeholders who have taken an interest in the Companies' regulatory review processes in the past, specific communities and select industrial customers. The FEU have held meetings with key stakeholders to:

- Inform them of the application;
- Discuss common rates and amalgamation;
- Receive feedback; and
- Develop approaches for the implementation of common rates and special contracts under the Amalgamated Entity where appropriate.

For example, consultation with the service area of Fort Nelson, which falls under the jurisdiction of the NRRM, took place to discuss amalgamation and the proposed phase-in approach for Fort Nelson common rates. Feedback obtained from representatives of the NRRM has been considered and has been factored into the proposed common rate approach for Fort Nelson as discussed below.

The FEU also commenced consultation and communication with the broader stakeholder community. Communications informed stakeholders of the impact and benefits of common rates and amalgamation, including the approximate proposed bill impact for each service area. Consultation activities included market research, bulletin board focus groups, face-to-face meetings with stakeholders, and Public Information Sessions in nine communities across the province. Feedback from stakeholders obtained through these activities has been taken into consideration in preparing the Application.

Upon filing of the Application, further communications will be provided to stakeholders through mail inserts, stakeholder letters, media releases and updates to the FortisBC website.[288]

10.2 Stakeholder Engagement Objectives

The objectives of the stakeholder engagement plan for this Application are to:

1. Inform stakeholders of the filing;
2. Provide information about the impact and benefits of common rates and amalgamation;

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[287] For example, TGVI's 2010-2011 Revenue Requirements and Rate Design Application (pp. 16, 27, and 404), and TGI's 2010-2011 Revenue Requirements Application (p. 17).

[288] www.fortisbc.com/commonrates

3. Communicate the proposed rate changes for the Amalgamated Entity; and
4. Provide opportunities for stakeholders to provide feedback which can then be considered and inform the Application prior to filing.

The stakeholder engagement activities used to achieve these objectives included key stakeholder engagement meetings, broader stakeholder engagement through media outreach, market research and public information sessions, as well as post-application consultation. Each of these is outlined in the following sections.

10.3 Key Stakeholder Engagement Activities

As an initial focus, the FEU sought to identify and consult with key stakeholders with respect to the Application. The key stakeholders identified by the FEU were:

- Stakeholders who have taken an interest in the Companies' regulatory review processes in the past:
  - *British Columbia Old Age Pensioner's Organization*
  - *Commercial Energy Consumers*
  - *BC Sustainable Energy Association*
- Select government staff and elected officials representing:
  - *The Northern Rockies Regional Municipality*
  - *The Ministry of Energy and Mines*
- Select industrial customers:
  - *BC Hydro*
  - *VIGJV*

Meetings with these key stakeholder groups took place to inform them of the Application and discuss common rates, amalgamation, and anticipated bill impacts. Through discussions about the upcoming filing, stakeholders were provided with the opportunity to pose questions and raise concerns, which the Companies have considered and, where appropriate, addressed in this Application. A summary of the meetings with key stakeholders, including names of attendees and meeting dates, can be found in Appendix E-1.

Meetings with the key stakeholders mentioned above will continue post-filing if requested by them, to address any further concerns or questions that they may have.

Due to the impact that common rates will have on Fort Nelson and the complexity of some special customer contracts, three key stakeholders - Fort Nelson, BC Hydro and the VIGJV – were identified as stakeholders requiring additional consultation. The following subsections discuss that consultation in detail.

10.3.1 FORT NELSON ENGAGEMENT

As discussed in Section 6.7 (*Impact of Common Rates on FEI and FEFN Customers*), the adoption of postage stamp rates will result in rate increases for FEI and Fort Nelson customers.

The FEU met with representatives from the NRRM, including the Mayor and Corporate Staff, to discuss common rates and amalgamation. Two meetings were conducted with the Mayor and Corporate Staff, one via teleconference, and one face-to-face in Fort Nelson. At both meetings the FEU representatives advised that feedback received would shape the approach for Fort Nelson common rates going forward and that the proposed common rates were subject to BCUC approval. Topics of discussion during the two meetings included the rationale behind the FEU's request, impact and benefits of amalgamation, and potential common rate implementation options. During the two meetings it was agreed that a one-time rate increase would result in too large of an impact on customers and the Mayor asked the FEU to consider alternatives to a one-time rate increase. Based on this feedback, the FEU proposed two common rate phase-in options for the service area of Fort Nelson (please see Appendix E-3, Fort Nelson Presentation, slide 5).

The FEU's proposed amalgamation and two common rate phase-in options were then presented by the Mayor, without FEU representatives present, to the NRRC, composed of Fort Nelson elected officials, on September 20th, 2011 and a vote was conducted to select the desired phase-in approach. "There was general agreement from Council that no matter what option was preferred, the entire scenario would result in an unfair rate increase on Fort Nelson residents"[289] but based on the two options presented the preference was to phase-in common rates over a 15-year period with any impact delayed until year six (refer to Appendix E-2 for approved NRRC Minutes[290] and Common Rates Phase-In Decision). The FEU agreed to propose this approach for Fort Nelson customers within this Application (see Section 8.4.1.1). If approved, Fort Nelson common rates will reach parity with the Amalgamated Entity by 2029.

For further information on feedback received from Fort Nelson customers, the NRRC and Fort Nelson & District Chamber of Commerce ("FNDCC"), refer to section 10.5 below.

10.3.2 VANCOUVER ISLAND GAS JOINT VENTURE ENGAGEMENT

As noted in Section 9.2, VIGJV was not included in the rate class mapping as it has a special Transportation Service Agreement ("TSA") in place with FEVI. The FEU have met with and had discussions with each of the individual members of the VIGJV to discuss the FEU's proposal for amalgamation and the appropriate approach for the agreement between FEVI and the VIGJV going forward under the Amalgamated Entity.

At the time of consultation, the TSA with the VIGJV was set to expire on December 31, 2012, subject to a five year extension as mutually agreed to by both parties, with notification to FEVI

[289] Northern Rockies Regional Council Minutes September 20, 2011, page 3
[290] Minutes approved at the Northern Rockies Regional Council meeting held on October 24th, 2011.

prior to October 1, 2011. Given the timing of the application to amalgamate, the VIGJV and the FEU agreed to extend the TSA for a five year term with VIGJV having the right to terminate the extension without penalty if the FEU were to amalgamate (refer to Appendix E-4 for VIGJV Transportation Service Agreement Extension Letter). If the VIGJV chooses to terminate the TSA upon amalgamation, the VIGJV will have the option to receive transportation service pursuant to one of FEI Amalco's rate schedules available to large industrial customers.

10.3.3 BC HYDRO ENGAGEMENT

FEI and FEVI currently have long-term service agreements (Transportation Service Agreement, Peaking Agreement and Capacity Assignment Agreement) in place with BC Hydro for service to the Island Cogeneration Plant on Vancouver Island. To ensure that BC Hydro is appropriately engaged with regards to its long-term service agreements, the FEU have met with representatives from BC Hydro to discuss the FEU's intent to apply for amalgamation and the implications it may have for its contracts with BC Hydro.

Discussions are on-going and the FEU will continue to work with BC Hydro to review the existing suite of agreements concerning service to the Island Cogeneration Plant on Vancouver Island and will amend any language that is required to maintain the original intent of the agreements if the FEU amalgamate.

10.4 Broader Stakeholder Engagement

The FEU's stakeholder engagement also included consultation with broader stakeholders, including municipalities, associations and customers in all service areas, through media outreach, market research and public information sessions.

10.4.1 COMMUNICATIONS & MEDIA OUTREACH

To communicate with and inform the broader stakeholder community of the Application, the FEU used communication tools, such as advertisements, web, mail and media, and also sought out media coverage through news releases, interviews and social media.

10.4.1.1 Communications

To promote awareness of the Application and the public information sessions, communications included:

- A webpage on *fortisbc.com,*[291] informing customers, the general public, employees and other stakeholder groups of the rationale for common rates and amalgamation, as well as the proposed rate changes, bill impacts and public information sessions being held in each region. In addition to the dedicated webpage, a banner on the main fortisbc.com webpage highlighted the Application and directed viewers to more information;

[291] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/CommonRatesAndRateDesign/Pages/default.aspx

- Publication of Frequently Asked Questions ("FAQ") documentation and the Public Information Session Storyboards on the webpage;
- Distribution of letters to commercial and industrial customers to inform them of the proposed rate changes and the approximate impact to their bills;
- Distribution of letters to municipalities, local government staff, and elected officials to inform them of the Application and the nine public information sessions (refer to Appendix E-9 for sample letter); and
- Advertisements in the following provincial and local newspapers:

Table 10.1: Newspaper Publications

Market	Publication	# of Publications	Week of
Newspaper Publications			
Victoria	Victoria News	2	January 30th
Victoria	Victoria Times Colonist	2	January 30th
Vancouver	Province	2	January 30th
Vancouver	Vancouver Courier East/West	2	January 30th
Vancouver	Vancouver Sun	2	January 30th
Vancouver	Westender	1	January 30th
Squamish	Squamish Chief	2	January 30th, February 6th
Whistler	Whistler Pique	2	January 30th, February 6th
Whistler	Whistler Question	2	January 30th, February 6th
Kelowna	Kelowna Capital News	2	February 6th
Kelowna	Kelowna Courier	2	February 6th
Courtenay Comox	Comox Valley Record	2	February 6th
Courtenay Comox	Courtenay Comox Valley Echo	2	February 6th
Prince George	Prince George Citizen	2	February 6th, February 13
Prince George	Prince George Free Press	2	February 6th
Delta	Delta Optimist	2	February 13th
Peach Arch	Peace Arch News	2	February 13th
Surrey	Surrey Leader	2	February 13th
Surrey	Surrey Now	2	February 13th
Cranbrook / Kimberley	Cranbrook Daily Townsman	2	February 20th
Cranbrook / Kimberley	Cranbrook Kootenay News Advertiser	2	February 20th
Fort Nelson	Fort Nelson News	2	February 13th, February 20th
Digital Publications			
Kelowna	Castanet	1	February 6th
Prince George	Prince George Citizen	1	February 6th
Victoria	Victoria Times Colonist	1	January 30th
Vancouver	Vancouver Sun Vancouver Province	1	January 30th
Surrey	Surrey Now Delta Optimist	1	February 13th

In addition to advertisements, web and mail communications, the Companies' intention to implement common rates through amalgamation has also been communicated in person with various stakeholders over the past year such as the Rental Owners and Managers Society of BC, Association of Vancouver Island and Coastal Communities ("AVICC"), Greater Victoria Chamber of Commerce, the Resort Municipality of Whistler and other Mainland and Vancouver Island municipalities.[292]

10.4.1.2 Media Outreach

In addition to the communications outlined above, the FEU sought media coverage through the issuance of a news release, interviews, and social media.

A news release was distributed in November to provincial media to inform media and the general public of:

- The FEU's November 1, 2011 Application for Amalgamation;
- The reasons for and benefits of common rates and amalgamation; and
- The proposed rate changes and bill impacts. *(See Appendix E-7 for News Release).*

While the present Application has superseded the November 1, 2011 Application, the information on amalgamation presented in the New Release is still consistent and relevant.

Media coverage (other than paid media, such as advertising) was gained through calling or emailing media outlets in order to draw attention to the public information sessions, and provide details about the Application. Interviews were conducted across the Province and media coverage was attained through radio, television, print and online stories.

The following interviews were conducted in 2012:

- February 8, CBC Radio, Kelowna
- February 8, CISQ FM Radio, Whistler (with reach to Sunshine Coast)
- February 9, CHEK TV, Victoria (with reach to Courtenay)
- February 13, Castanet News, Kelowna
- February 14, AM 1130 Radio, Kelowna
- February 14, CILK FM Radio, Kelowna
- February 14, Whistler Pique newspaper, Whistler
- February 14, KBS Radio, Nelson (with reach to Kootenay area)
- February 14, EZ Rock, Trail (with reach to Kootenay area)
- February 16, 97 FM Radio, Prince George

[292] Refer to Appendix E-1 for complete list of stakeholders.

- February 16, Prince George Citizen newspaper, Prince George
- March 6, CBC Daybreak Radio, Prince George (with reach to Fort Nelson)
- March 6, Fort Nelson News newspaper, Fort Nelson

The interviews noted above resulted in the following media coverage:

Table 10.2: Media Coverage

Date	Media outlet	Time	Approximate # of Listeners/Viewers *(if available)*
	Radio & Television		
Feb 8	CISQ FM, Whistler	8:00 am	
Feb 9	CBC Radio, Kelowna	6:30 am	5,000
Feb 9	CBC Radio, Victoria	6:30 am	11,000
Feb 9	CBC Radio, Kelowna	6:51 am	5,000
Feb 9	CBC Radio, Victoria	7:30 am	15,000
Feb 9	CBC Radio, Vancouver	7:30 am	54,000
Feb 14	CKFR FM, Kelowna	8:00 am	4,000
Feb 14	CKFR FM, Kelowna	Noon	4,000
Feb 14	CKKC FM, Nelson	8:00 am	
Feb 14	CILK FM, Kelowna	8:00 am	9,000
Feb 16	CJCI FM, Prince George	4:00 pm	3,000
March 6	CBC Radio, Prince George/Fort Nelson	6:45 am	
	Print & Website Postings		
Feb 9	CBC website	Website	
Feb 13	Castanet news, Kelowna	Website	
Feb 14	AM 1150 news, Kelowna	Website	
Feb 14	EZ Rock FM, Trail	Website	
Feb 16	HQ Prince George	Website	
Feb 16	Prince George Citizen	Website and print	
Feb 16	Prince George Free Press	Print	28,601

The established FortisBC Twitter account was also used to draw awareness to the public information sessions. Generic tweets were posted for all FortisBC followers, with a link to the information session webpage on fortisbc.com. Targeted @replies were also posted to reach out to either the local Chambers of Commerce – if on Twitter – or local online outlets and events listing services that target the area.

10.4.2 MARKET RESEARCH

The FEU contracted with Vision Critical, a leading 3rd party research vendor, to determine:

- Residential customer attitudes to common rates and amalgamation before and after key messaging was offered;
- Levels of support on a regional basis; and
- Concerns or specific objections to the proposed changes.

In consultation with the FEU's market research team, Vision Critical developed and recommended a quantitative study using web based surveys and a qualitative study using web based bulletin board focus groups.

Quantitative research is used to measure how people feel, think or act in a particular way. These surveys tend to include large samples and are structured questionnaires that incorporate questions with set responses. Qualitative research on the other hand seeks out the 'why', not the 'how,' of its topic through the analysis of unstructured information. Qualitative research is designed to "elicit a range and depth of opinions rather than to measure proportions or percentages."[293] Both approaches were used to get a thorough understanding of how residential customers perceive the common rates application and how to best communicate the proposal going forward. Both types of research provide different perspectives and complement each other.

Whistler customers were not included in the quantitative or qualitative market research because:

- a small population of FEU customers live in the area (2,300 residential customers);
- there is a very high seasonal occupancy rate for properties in Whistler (during the conversion project from propane to natural gas FEW found that approximately 70% of the residential dwellings in Whistler were not occupied year-round), which makes it difficult to contact the property owner;
- many property owners live outside of British Columbia; and

[293] Appendix E-6, Vision Critical Qualitative Market Research Report, "Residential Customer Opinions - Common Rates Qualitative Research Report", page 7

- a substantial number of properties in Whistler are part of rental property pools managed by third party management companies, which also makes it difficult to contact the property owner. [294]

While Fort Nelson was included in the quantitative market research, a dedicated qualitative focus group was not needed for Fort Nelson customers due to the key stakeholder consultation conducted with Fort Nelson described above and the Fort Nelson public information session described below.

More detail on the quantitative and qualitative studies is provided below.

10.4.2.1 Quantitative Study: Surveys

For the quantitative study, Vision Critical randomly selected residential customers from the FEU's service areas (except Whistler) and invited them to complete a web-based survey. Of the residential customers invited, 948 completed the web based surveys. This number of completed surveys results in a standard error of ±3.2% at the 95% confidence level, meaning that results will be accurate within 3.2% 19 out of 20 times.

To make the survey results representative of the FEU's residential customer base, Vision Critical collected a sample that was as close to the general population as possible so that less weighting was required when analyzing the results. They did this by "balancing" the survey invitations they sent out so that the data collected reflects the general population variables such as gender and age as closely as possible. Vision Critical then weighted the data to reflect the FEU's natural gas regional customer distribution. More "weight" was given to responses from the larger service areas than the smaller service areas when looking at total results. However, Vision Critical also set minimum quotas per region to give the FEU enough completed surveys to look at results within each service area surveyed. While minimum quotas were reached for the Vancouver Island, Lower Mainland, Inland and Columbia service areas, only 14 Fort Nelson customers completed surveys, which is not a statistically significant amount. The results obtained for Fort Nelson should therefore be viewed as directional only.

The results of the survey showing customer reactions to the FEU's common rates proposal are included as Appendix E-5 to the Application. Key findings are discussed in section 10.5 (Feedback).

10.4.2.2 Qualitative Study: Focus Groups

The qualitative study aimed to gather an in-depth understanding of how residential customers feel about the proposal and the reasons that govern such feelings. To accomplish this, three web-based bulletin board focus groups were held, encompassing residential customers from the Lower Mainland, Inland, Columbia and Vancouver Island service areas.

[294] Appendix E-5, Vision Critical Quantitative Market Research Report, "Residential Customer Opinions - Common Rates Research Survey Quantitative Report", page 2

Each focus group consisted of 12-15 FEU natural gas residential customers. Focus group participants were posed a series of questions over a 2.5 day period and were given the ability to answer questions, pose questions or comment on other responses from focus group members. In particular, participants were asked about their feelings about common rates and their communication needs with respect to the FEU's proposal.

The results of the qualitative study showing customer reactions to the FEU's common rates proposal are included as Appendix E-6 to the Application. Due to the small sample size, the results should be interpreted as directional in nature. Key findings are discussed in section 10.5 (Feedback).

10.4.3 PUBLIC INFORMATION SESSIONS

The FEU held nine information sessions across the province to ensure that the broader stakeholder community, including interested residents, commercial customers, First Nations, and government stakeholders, were provided with an opportunity to learn about and provide feedback for the Application. The public information sessions encouraged attendees to learn more about the drivers for common rates, in addition to the benefits and proposed impacts of common rates for all natural gas customers. Storyboards were provided to help guide attendees through the proposal and all attendees were encouraged to ask questions and provide feedback (refer to Appendix E-12 for a complete set of Storyboards).

The public information sessions were advertised in local news media across the six natural gas service areas, on the FortisBC website and through letters to local government officials/staff, First Nations groups, and business associations. For the list of stakeholder letters and sample notifications, see Appendices E.

The nine public information sessions were conducted in the following communities:

Table 10.3: Public Information Sessions

Community	Location	Date	Time	Number of Attendees
Victoria	Harbour Towers Hotel	02/06/2012	6:00-8:00pm	2
Vancouver	Italian Cultural Centre	02/07/2012	6:00-8:00pm	10
Whistler	Whistler Convention Centre	02/13/2012	6:00-8:00pm	2
Kelowna	Holiday Inn Express	02/14/2012	6:00-8:00pm	7
Courtenay	Crown Isle Resort	02/15/2012	6:00-8:00pm	5
Prince George	Prince George Civic Centre	02/16/2012	2:00-6:00pm	7
Cranbrook	Prestige Rocky Mountain Resort	02/28/2012	6:00-8:00pm	10
Fort Nelson	Woodlands Inn	03/01/2012	6:00-8:00pm	13
Surrey	Surrey Central Library	03/05/2012	6:00-8:00pm	6

At each session, attendees were provided with an information sheet (see Appendix E-10) detailing the proposal, and FEU employees were available to answer any questions that they may have had. Once attendees had reviewed the storyboards and their questions had been answered, they were asked to fill out a feedback form and provide comments on common rates (refer to Appendix E-11 for sample feedback form).

A total of 62 people signed in to the nine information sessions, representing residential and small commercial customers, and the FEU received 46 completed feedback forms. A summary of the feedback form results and comments can be found below in Section 10.5.3.

10.4.4 LARGE COMMERCIAL & INDUSTRIAL ENGAGEMENT

Due to the relatively large impact that common rates could have on customers that consume large volumes, the FEU specifically engaged the large commercial and industrial customers. To engage these customers, the FEU sent an electronic letter informing the customers of the Application and provided background information regarding common rates, amalgamation and the impact to rates. The letter incorporated a link to a short online survey to gather feedback on the Application. The letter explained to customers that the FEU were gathering feedback from customers regarding the Application and would submit the feedback to the BCUC to be incorporated in the review of the Application.

The letter was sent to 884 of FEI's large commercial and industrial customers,[295] 80 of the larger FEVI customers and 75 of the larger FEW customers. The customers that the FEU contacted represent all of the Large Commercial and Industrial customers that the FEU currently has in its contact database. The customers that received the communication were from a wide cross section of sectors, such as education, municipalities, restaurants, recreation facilities, hotels, manufacturing, multifamily/apartments, offices, agriculture, food & beverage processing, wood products and mining. Together, the letter was sent to a total of 1,039 contacts which represent approximately 2,000 accounts across the FEU.

A total of 50 customer representatives completed the online survey. A summary of the feedback form results and comments can be found below in Section 10.5.4.

10.5 Feedback

Feedback from the NRRC, VIGJV, BC Hydro and the broader stakeholder community has been considered and factored into this Application where appropriate. Other Interveners, while interested in the consultation, did not provide specific feedback on the Application or the proposal for common rates or amalgamation. Stakeholders, including residential and small commercial customers, were provided with the opportunity to provide feedback via the common

[295] The customers were from FEI's rates 5, 7, 23, 25, 27 and 22.

rates webpage on FortisBC.com, by attending one of the nine public information sessions held throughout the province, and residential customers were asked to participate in the market research online study and bulletin board focus groups conducted by Vision Critical. In addition, 1,039 Commercial and Industrial contacts were informed of the Application and asked to provide feedback.

The following subsections summarize the stakeholder feedback obtained.

10.5.1 KEY STAKEHOLDER FEEDBACK

As previously detailed in section 10.3, consultation with key stakeholders took place prior to filing this Application. No major concerns were raised by the stakeholders who have taken an interest in the Companies' other regulatory review processes in the past and feedback received from BC Hydro and VIGJV will shape their specific contracts with the FEU if amalgamation is approved.

Despite a proposed 15 year phase-in period, feedback received from Fort Nelson customers, the NRRC and Fort Nelson & District Chamber of Commerce is not supportive of the proposal for common rates. The Fort Nelson & District Chamber of Commerce has submitted two letters to the British Columbia Utilities Commission outlining its view that common rates are not in the best interest of Fort Nelson customers (see Appendix E-15 for Fort Nelson & District Chamber of Commerce BCUC Letters). Part of the information provided within the letters is based on the FEU's November 2011 application that has subsequently been withdrawn and replaced with this Application. Other information is based on the Chamber of Commerce's perception of meetings between the FEU and the NRRM Mayor and Corporate Staff that they did not attend. The FEU have provided a response to a number of the statements in these letters in Appendix E-16.

While Fort Nelson customers will see a significant increase to their rates as a result of common rates, the FEU believe that Fort Nelson will benefit from the proposals as described in Sections 6.3 and 6.5.

For further feedback received from Fort Nelson customers, please see section 10.5.2 for market research results across the Province, and section 10.5.3, which summarizes the feedback received from public information session attendees.

10.5.2 MARKET RESEARCH FEEDBACK

As discussed previously, quantitative and qualitative market research was conducted to quantify awareness and opinions of this Application, in addition to determining which messages resonate with customers for future communications.

Based on results from the quantitative study, which obtained a total of 948 completed online surveys, Vision Critical reports that "before actually seeing the rate impact on their particular region, customers are moderately receptive to the common rates application."[296] When participants were asked whether they support or oppose the idea of paying the same rates for services such as natural gas, fuel oil, electricity, telephone, cable, and gasoline, regardless of where they live, over half of the customers believed that it makes sense to pay the same rates.[297]

Prior to viewing the impact of common rates on each service area, when asked how much they support the common rates application, only 16% of those surveyed opposed the common rates proposal. Once the impacts were shared however, the opposition percentage increased to 44%, while 53% remained supportive or neutral.[298]

In addition, similar results were found when participants were asked in a later question whether they support the statement that "the move to common natural gas pricing across the province makes sense for FortisBC customers". 56% of those surveyed somewhat to strongly supported the statement prior to viewing the impacts, while only 16% somewhat to strongly opposed it. Once the impacts were shared, the percentage of those participants who originally somewhat to strongly supported the statement, decreased to 41%, and those that opposed or strongly opposed the statement increased to 34% (the percentage of respondents with a neutral response increased only slightly from 20% pre-impact to 21% post-impact).[299]

As expected, Vancouver Island participants were the most supportive of common rates with only 11% opposing the move to common rates across the service areas. Fort Nelson participants on the other hand, strongly opposed common rates, with only 19% of participants being somewhat supportive. For the Lower Mainland and Interior service areas, 37% and 38% respectively supported the idea of common rates across the Province once the impacts had been shared, while 36% and 39% opposed it.[300]

In the qualitative study, Vancouver Island customers were positive about the decrease but at the same time were upset that common rates have not been proposed sooner.[301] Lower Mainland, Inland and Columbia[302] customers were dissatisfied with common rates, but this is largely due to the impact, not the idea of common rates in general. One Lower Mainland customer stated that, "I didn't realize people paid different rates based on where they live. If our rates don't go up I would be in support of this change since it's revenue-neutral for the company. It sounds like it's

296 Appendix E-5, Vision Critical Quantitative Market Research Report, "Residential Customer Opinions - Common Rates Research Survey Quantitative Report", page 8
297 Ibid. page 4
298 Appendix E-5, Vision Critical Quantitative Market Research Report, "Residential Customer Opinions - Common Rates Research Survey Quantitative Report", page 4
299 Ibid. Pages 13, 14
300 Ibid. page 14
301 Appendix E-6, Vision Critical Qualitative Market Research Report, "Residential Customer Opinions - Common Rates Qualitative Research Report", page 12
302 Inland and Columbia customers are referred to as BC Interior and Columbia/Kootenays customers respectively in Vision Critical Market Research Reports

an initiative to help customers in need."[303] Another customer from the Interior stated that, "It would be more effective and fair to have a "common rate" all across the province and would allow for more services to everyone."[304]

The FEU recognize that the support for common rates is largely dependent on rate impact and has taken this feedback into consideration. Based on recommendations obtained through the qualitative research, which saw that customers would rather see common rates phased-in over a three year time period,[305] the FEU has adjusted its allocation of the RSDA and is proposing to phase-in the effects of common rates for Lower Mainland, Inland and Columbia service area customers over three years.[306] As discussed in Section 8.4.1.3, returning the RSDA in 3 equal annual installments is forecast to limit delivery rate annual bill increases from amalgamation on Lower Mainland, Inland and Columbia customers until rates are aligned in 2017.

In addition to providing comments on common rates, focus group participants stated that they want and expect more information on why the proposal is being put forward at this time, why there are three legal entities and what the benefits of the proposal are.[307] The FEU has taken this feedback into consideration and sections 2, 3, and 6 of the Application address all of these requests for further information in detail. If the Application is approved, customers would like time to prepare and expect to be notified of the change to their rates six months ahead of time.[308] If this Application is approved, the FEU are planning to implement common rates for January 1, 2014 and will provide notice to customers three to six months prior to the change.

10.5.3 PUBLIC INFORMATION SESSION FEEDBACK

The following results obtained from the public information sessions are directional only due to the small number of customers, 62 in total, who attended the nine sessions across the Province. Of the 62 customers that attended, 46 individuals completed a feedback form and 13 responders represented Fort Nelson, the smallest FEU service area.

Overall, Vancouver Island and Whistler customers were very supportive of the proposal for common rates and service offerings across the province. Eight out of nine respondents agreed or strongly agreed that customers should pay the same rate for natural gas regardless of where they live and that this proposal makes sense for our customers. One Courtenay customer commented that "It's about time! Everybody paying the same in British Columbia. Its getting too expensive to use and people are looking at different ways of heating their homes."

Feedback received from FEI customers ranged from strong support to strong opposition; however, over half of the respondents agreed or strongly agreed that customers should pay the

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[303] Appendix E-6, Vision Critical Qualitative Market Research Report, "Residential Customer Opinions - Common Rates Qualitative Research Report", page 11
[304] Ibid. page 11
[305] Ibid. page 16
[306] Refer to Section 8.4.1.3 for further information on three year phase-in of rates for FEI customers.
[307] Appendix E-6, Vision Critical Qualitative Market Research Report, "Residential Customer Opinions - Common Rates Qualitative Research Report", page 16
[308] Ibid.

same rate for natural gas and have access to the same service offerings regardless of where they live. Only 6 out of 23 respondents felt that this proposal did not make sense for FortisBC customers and one Prince George customer stated that “Streamlining the cost of gas across the province sounds logical as long as our gas bills do not increase dramatically because of our winters as compared to the lower mainland weather”. While many were supportive, some customers still felt that each service area should pay a rate based on their cost of service and that Mainland customers should not subsidize Vancouver Island and Whistler customers.

Regardless of industry or type of utility, large increases are generally not desirable in the eyes of the public and as expected, Fort Nelson attendees were not in favour of the proposal. All respondents either disagreed or strongly disagreed with the statement that customers should pay the same rate for natural gas regardless of where they live. When asked about services, however, respondents were split with regards to having access to the same services and offerings regardless of location. Based on comments received, respondents felt that the proposal was unfair for Fort Nelson customers, that a rate reduction should be given to customers in colder climates and that they should not pay transportation costs.

The feedback obtained at the public information sessions aligns with that received from the market research and should be weighted accordingly. While Fort Nelson strongly opposes the proposal for common rates, the majority of customers in the larger service areas of the Lower Mainland, Inland and Columbia do not oppose common rates, and the Vancouver Island and Whistler service areas strongly support the proposal.

For a breakdown of the public information session feedback, please refer to Appendix E-13.

10.5.4 LARGE COMMERCIAL & INDUSTRIAL FEEDBACK

Out of the 1,039 letters sent out to commercial and industrial contacts, 50 individuals completed the feedback questionnaire and 30 commented on the proposal. Due to the minimal number of responses received, responses should be viewed as directional only and do not statistically represent the commercial and industrial customer base. Of the 50 respondents, 32 are FEI customers, while 18 represent Vancouver Island, Sunshine Coast, Powell River and Whistler customers. When asked whether they agree that customers should pay the same rate for natural gas regardless of where they live or operate their business, 22 out of 50 respondents disagreed or strongly disagreed with the statement and 24 agreed or strongly agreed.[309] With regards to programs and service offerings across the Province, the majority were in favour of having access to the same programs and service offerings regardless of location - 29 respondents agreed or strongly agreed that customers should have access to the same programs and service offerings regardless of location, while 19 disagreed or strongly disagreed with the idea.[310]

[309] 4 out of 50 respondents provided an answer of “Neither Disagree nor Agree” or “Don’t Know.”
[310] 2 out of 50 respondents provided an answer of “Neither Disagree nor Agree” or “Don’t Know.”

Similar to the market research comments and website feedback, comments received from the Commercial and Industrial customers ranged from strong opposition to strong support. Some businesses believe that this proposal will negatively impact their operations and is unfair for businesses that have set up on the Mainland. One customer stated that they "disagree with making the cost of gas cheaper in areas where the actual cost is higher. This seems to me to be an incentive for people and companies to set up in areas where the actual economics don't make sense and penalizes those people that are located in areas that make more economic sense." Another individual who did not agree with the proposal commented that "Business locations are often determined by utility costs, transportation costs and proximity to suppliers. Increasing costs to long-established businesses for the betterment of Vancouver Island residence is not acceptable."

In contrast, numerous comments were received that strongly support the proposal for common rates. One Vancouver Island customer stated that "We fully support this proposal as a large employer on Vancouver Island. Businesses should not be penalized with higher natural gas costs based on where they operate. This initiative will contribute to our competitiveness and ability to sustain and increase employment where we operate." Another customer commented that "As a resident of Vancouver Island I would certainly appreciate the rate relief offered for my own domestic purposes. I also work in the forest products industry and can see first-hand how the rate discrepancies for an island industrial user adversely effects our economic viability when compared to the industrial rates enjoyed by users on the lower mainland - the current rate structure puts us at a significant disadvantage. The lower rate structure (if approved) may enable us to pursue additional business which could lead to increased employment."

A detailed summary of the Large Commercial and Industrial feedback, including question results and comments, can be found in Appendix E-14.

10.5.5 WEBSITE & STAKEHOLDER LETTER FEEDBACK

Only 29 comments were received via the website feedback form and many were questions concerning the impact of common rates and billing concerns, rather than comments on the common rates proposal. Of the comments focused on this Application, feedback was split between support and opposition. Respondents spanned all six service areas, and comments mirrored results obtained from the other feedback venues. Some customers felt that the increase in FEI rates was too large and that Vancouver Island residents should pay a higher premium for receiving goods on the island. Other FEI customers did not agree with that sentiment and felt that common rates would create a level playing field similar to other utilities in the Province.

With regards to stakeholder letters, over 400 letters were sent out to various types of stakeholders across the Province, including MLAs, municipal Chambers of Commerce, First Nations groups, Mayors and municipal corporate staff (refer to Appendix E-8 for Stakeholder Letter Contact List). Less than 10 responses were received, and each respondent inquired about the impact that common rates would have on their specific municipality.

In addition to rate impact inquiries, six letters of support have been received prior to filing this Application from the following stakeholders; Whistler Chamber of Commerce, District of North Saanich, Corporation of the District of Saanich, Village of Cumberland, AVICC, and the Town of Qualicum Beach (see Appendix E-17 for letters).

10.6 Post-Application Filing Activities

Following the filing of this Application, stakeholder engagement activities will continue. In addition to the Commission's notice requirements, the following activities are scheduled to take place:

1. Post-Filing:
    - Bill inserts sent to all residential, commercial and industrial customers, informing them of the filing; and
    - Meetings with key stakeholders noted in Section 10.2, if requested.
2. Post-Approval (If common rates and amalgamation are approved):
    - Bill insert sent to all residential, commercial and industrial customers, outlining the rate changes 6 months prior to implementation;
    - A second bill insert sent out to FEVI, FEW and FEFN customers, detailing changes to their bill structure. FEVI, FEW and FEFN each have a distinct bill structure, which will be changed following the implementation of common rates to align with the rest of the FEU;
    - FortisBC website article outlining rate changes; and
    - Distribution of letters to First Nations, suppliers, lenders and other third parties to inform them of the amalgamation and that any agreements with FEI, FEFN, FEVI and FEW are still effective under the Amalgamated Entity.

10.7 Summary of Engagement

The Common Rates, Amalgamation and Rate Design Application stakeholder engagement plan included communication and consultation with a broad range of stakeholders through a variety of activities. Through activities such as stakeholder meetings, public information sessions, market research, bill inserts, web, media outreach and customer letters, stakeholders have been and will continue to be appropriately notified, consulted and sufficiently informed of the impact of common rates. Feedback obtained through the consultation process has been reviewed and incorporated into the Application where appropriate.

Based on the feedback received from customers, Vancouver Island and Whistler customers are very supportive of the common rates proposal, whereas Fort Nelson customers strongly oppose it. Due to the impact to Fort Nelson customers, the FEU is proposing to phase-in common rates over a 15-year period. While the majority of Lower Mainland, Inland and Columbia customers do not oppose the idea of common rates, support is largely dependent on rate impact. As such, the FEU is proposing to phase in Mainland rates over a period of three years to mitigate the impact on FEI customers.

As discussed in this section, the FEU have broadly engaged its stakeholders with respect to the Application and will provide notice to customers of any rate changes if the Application is approved.